INDEX

TAB #	DOCUMENT
1	*Lockridge v. Director, Ministry of the Environment*, 2012 ONSC 2316
2	*Fairfield v Director, Ministry of the Environment, Ontario Environmental Review Tribunal*, 93 C.E.L.R. (3d) 135.
3	*Marchand (Litigation Guardian of) v Public General Hospital Society of Chatham (2000)*, 51 O.R (3d) 97 (Ont. C.A.)
4	*Statutory Powers Procedure Act*, R.S.O 1990, c. S.22, s. 15.
5	EB-2022-0318, Exhibit B-1-2 – 2023-2025 Business Plan
6	EB-2024-0004, Exhibit D-1-2, Attachment 2 – Organizational Chart
7	EB-2019-0242, AMPCO Decision and Order, January 23, 2020
8	EB-2007-0040, AMPCO Decision and Order, April 10, 2007
9	Ontario Energy Board, Market Surveillance Panel, Monitoring Report on the IESO-Administered Electricity Markets for the Period from May 2015 – October 2015
10	EB-2020-0230, IESO Interrogatory Responses
11	*Ontario Energy Board Act, 1998*, SO 1998, c 15, Sch B
12	EB-2019-0242, Summary Closing Submissions of the IESO, December 9, 2019

TAB 1

CITATION: Lockridge v. Director, Ministry of the Environment, 2012 ONSC 2316
DIVISIONAL COURT FILE NO.: 528/10
DATE: 20120607

ONTARIO

SUPERIOR COURT OF JUSTICE

DIVISIONAL COURT

2012 ONSC 2316 (CanLII)

BETWEEN:	
ADA LOCKRIDGE and RONALD PLAIN Applicants	*Justin Duncan, Kaitlyn Mitchell, Margot Venton*, for the Applicants
– and –	
DIRECTOR, MINISTRY OF THE ENVIRONMENT, HER MAJESTY THE QUEEN IN RIGHT OF ONTARIO, AS REPRESENTED BY THE MINISTER OF THE ENVIRONMENT, THE ATTORNEY GENERAL OF ONTARIO and SUNCOR ENERGY PRODUCTS INC. Respondents	*Jack Coop, Jennifer Fairfax, Lindsay Rauccio*, for the Respondent, Moving Party, Suncor Energy Products Inc. *Lise Favreau, Kristin Smith, Robin Basu, Matthew Horner*, for the Respondents, Director, Ministry of the Environment, Her Majesty the Queen in right of Ontario, as represented by the Minister of the Environment and the Attorney General of Ontario
	HEARD at Toronto: January 31, February 1, February 2 and March 5, 2012

REASONS FOR DECISION

Harvison Young J.

Overview

[1] The applicants, Ada Lockridge and Ronald Plain, have commenced an application in which they seek judicial review of a decision made by the Director of the Ministry of the Environment (the "Director") under the *Environmental Protection Act*, R.S.O. 1990, c. E.19 (the "EPA"), in April 2010, respecting the sulphur output of Suncor's Plant #4 Sulphur Recovery Unit

in Sarnia. At the heart of their application is their claim that the failure of the Director to conduct a cumulative effects assessment prior to making his decision infringed the applicants' s. 7 and s. 15 *Charter* rights, as well as their rights to procedural fairness.

[2] The government respondents include the Director, Ministry of the Environment, Her Majesty the Queen in right of Ontario, as represented by the Minister of the Environment and the Attorney General of Ontario. They will be referred to collectively as the Government respondents in these reasons.

[3] The respondents have brought two motions in respect of this application. First, the respondent Suncor Energy Products Inc. brings a motion to strike the application as a collateral attack on earlier approvals granted to it pursuant to the EPA regime. It submits that the applicants' claims, in raising alleged health and emissions issues which predated the April 2010 Decision, constitute collateral attacks on earlier decisions, and particularly, the approvals relating to the construction of the sulphur production facility in 2004. For the reasons that follow, I would dismiss the motion to strike the application.

[4] Second, the respondents (the Government respondents as well as Suncor) bring a motion to strike some or all of the affidavit evidence filed by the applicants. They argue that as the issues in this application only relate to the April 2010 Decision, much of the evidence filed by the applicants respecting emissions that were not the subject of that decision, or the health effects allegedly flowing from those emissions, is irrelevant. In addition, they seek to strike considerable amounts of the evidence on the grounds that it constitutes improper opinion evidence, inadmissible hearsay, argument or speculation. This consumed the majority of the 4 days of oral argument taken for the three motions. As the following reasons set out, I have concluded that some portions of the evidence should be struck, although I would dismiss the motion with respect to much of it, without prejudice to the respondents' right to argue the admissibility issues before the panel hearing the application on its merits.

[5] Finally, the applicants have brought a motion for a protective costs order insulating them, absent improper conduct during this litigation, from adverse costs if their application for judicial review is ultimately successful. For the reasons I set out below, I would dismiss this motion.

Background

[6] The applicants are members of Aamjiwmaang First Nation who have commenced this application in their individual capacities. Ms. Lockridge is a resident of Aamjiwmaang First Nation. Mr. Plain has lived there for much of his life but now lives in Sarnia. The applicants claim that the Decision violates their rights to procedural fairness, to life, liberty and security of the person pursuant to s. 7 of the *Charter of Rights and Freedoms*, and to equality pursuant to s. 15 of the *Charter of Rights and Freedoms*. The applicants claim that, because pollution surrounds their reserve community and has a significant impact on them, the Director should not have approved additional pollutant releases without considering the cumulative effects of all of the pollution.

2012 ONSC 2316 (CanLII)

[7] The applicants seek various relief, including declarations that the Decision violated their ss. 7 and 15 *Charter* rights and that the "Minister's failure to apply the [*Environmental Bill of Rights, 1993*, SO 1993, c. 28 (the "EBR")] in a manner that ensure that cumulative effects were considered and minimized when the Director made the Decision infringed the Applicants' rights…".

[8] Both the motion to strike the application and the motion to strike the evidence are grounded in the respondents' submission that the application is, in substance, a challenge to the regulatory framework and, in particular, the absence of a cumulative effects assessment as part of the regular emissions approval processes. The application is not, they assert, really a challenge to a particular administrative decision at all. To the extent that it is, it essentially impugns administrative approvals granted long before the April 2010 Decision to the extent that they allegedly contribute to the cumulative effects complained of. The applicants have been quite frank in acknowledging before the court that the general absence of cumulative effects assessment from the approvals process under the EPA framework is their driving concern.

[9] All the respondents argue that this systemic issue is not properly the subject of a judicial review application. Suncor seeks the dismissal of the application, arguing that in raising issues of pollution and emissions that predate the April 2010 Decision, it is essentially a collateral attack on approvals that Suncor had previously obtained in full compliance with the regulatory requirements, and upon which approvals it has relied since.

[10] The Government respondents do not seek the dismissal of the application, but do, along with Suncor, seek to strike the evidence filed which, they argue, goes far beyond the narrow scope of the judicial review of the 2010 Decision. They seek to have the evidence circumscribed or "scoped" to reflect the proper scope of a judicial review application.

[11] The issues raised in both Suncor's motion to strike the application and the motion to strike the affidavit evidence overlap to some extent. I will address the two motions in turn, but it will be helpful to set out the April 2010 Decision and its context at the outset.

The April 2010 Decisions

[12] The applicants challenge two related decisions made by the Director under the EPA in April 2010 respecting the sulphur output of Suncor's Plant #4 Sulphur Recovery Unit in Sarnia. These are (1) Director's Amending Order No. 1131-7DJ25B-A ("Amending Order") dated April 1, 2010, and (2) the Director's Notice of Revocation of the Ordered Items in the Amending Order dated April 30, 2010. These are collectively referred to as the "Decision" or as the "Director's Decision".

[13] The Director's Amending Order and Notice of Revocation modified an administrative order which had been issued on April 15, 2008 ("the 2008 Order"), in response to the flaring from Plant #4. Emergency flaring is required in order to prevent quantities of hydrogen sulphide from being discharged into the atmosphere. The "flaring" converts the hydrogen sulphide into sulphur dioxide with the goal being to prevent the release of hydrogen sulphide directly into the atmosphere. This flaring, occurring shortly after the sulphur recovery units commenced

2012 ONSC 2316 (CanLII)

operations in 2007, was necessitated by "process upsets", which included unexpected failures of newly installed equipment, fabrication problems, design problems and a lack of operational experience (see affidavit of Peter Lynch, at para. 65-66). According to Suncor's predictive modeling, these flares caused "exceedances" in the predicted level of sulphur dioxide from Plant #4. As a result, the 2008 Order capped sulphur production from Plant #4 at 145 tonnes/day. This was a reduction from the rate of 250 tonnes/day that had been approved under the Certificate of the Approval, which had been issued in 2004 ("Certificate of Approval"). These decisions were concerned exclusively with the production of sulphur at the Plant and with two substances emitted by the Plant: sulphur dioxide and hydrogen sulphide.

[14] The 2008 Order specifically directed that Suncor take action to ensure compliance with sulphur dioxide and hydrogen sulphide emissions standards following the flaring incidents. It did not address any other emissions from Plant #4, or any other facility.

[15] On April 1, 2010, the Director issued the Amending Order to amend the 2008 Order. That order recognized certain improvements made by Suncor since the flaring incident and directed Suncor to take extra measures to monitor and report to the Ministry with regard to the operations of Plant #4 to ensure compliance with government standards. The Director informed Suncor that when certain parts of the Amending Order were fully complied with, the Director would exercise his discretion and revoke the pre-amendment requirements of the 2008 Order. This would in effect permit an increase in sulphur production to 180 tonnes/day. Again, the Amending Order addresses only the issues of sulphur production and sulphur dioxide and hydrogen sulphide emissions from Plant #4.

[16] On April 30, 2010, the Director revoked the original 2008 Order but left certain portions of the Amending Order in effect, thereby authorizing an increase in sulphur production to a level of 180 tonnes/day at Suncor's Plant #4. The two orders that comprise the impugned decisions are directed at ensuring that sulphur dioxide and hydrogen sulphide emissions are limited during both regular operation and acid gas flaring events at Suncor's Plant #4.

[17] The Director did not purport to amend the Certificate of Approval (Air) for Plant #4, which had been issued on November 25, 2004. This Certificate of Approval allowed Suncor (subject to any prevailing orders) to produce 250 tonnes/day of sulphur from hydrogen sulphide in Suncor's process streams.

[18] In short then, Suncor's Certificate of Approval granted in 2004 had authorized sulphur production of 250 tonnes per day. This was superseded by the 2008 Order, which reduced the sulphur production to 145 tonnes/day. The Director's Decision of April 2010 approved an increase to 180 tonnes/day, still within what Suncor refers to as the "envelope" that had been approved in 2004. Suncor's position is that the 2008 Order was a temporary measure designed to control excess sulphur dioxide emissions while Suncor remedied the problems which had necessitated the emergency flaring.

[19] The applicants argue that the failure to consider the cumulative effect of the production increase authorized by the April 2010 Decisions in the circumstances constituted breaches of

2012 ONSC 2316 (CanLII)

their ss. 7 and 15 *Charter* rights. The Application also alleges that the impugned decisions lacked appropriate jurisdiction under the EPA and that they were procedurally unfair, particularly because the applicants were not given notice of the 2010 Decisions.

I. THE MOTION TO STRIKE THE APPLICATION

[20] The respondent Suncor seeks to strike the application, in whole or in part, as an improper collateral attack and an abuse of process. In the alternative, it seeks to quash or stay the application on the grounds of laches and undue delay.

[21] As Mr. Coop for Suncor readily acknowledged at the outset, the collateral attack argument is at the core of Suncor's motion to strike the application. The abuse of process argument rests on the submission that the passage of time since the earlier approvals, as well as the fact that Suncor complied with the regulatory process in place in obtaining them, combine to render the application, to the extent that it is a collateral attack on prior approvals granted, an abuse of process. Similarly, the laches argument is not raised with respect to the April 2010 Decision, but with respect to the earlier decisions which Suncor submits are being collaterally attacked by the application.

[22] At the heart of Suncor's motion to dismiss the application is the argument that, despite their claim that they are only challenging the April 2010 Decision, the wide-ranging evidence adduced by the Applicants challenges all of the contaminants emitted by both the Sulphur Plant and Suncor's Sarnia Refinery as a whole. Suncor submits that their evidence questions the very right of the Sarnia Refinery to exist/operate at all without a cumulative effects assessment, and that, in light of this, it is disingenuous for the applicants to claim that they are only challenging the 2010 Decision.

[23] In substance, Suncor maintains, this application constitutes: (1) a collateral attack upon the Director's decision in November 2004 approving Suncor to build and operate the Sulphur Plant; and, (2) a collateral attack upon all fifty of the refinery approvals granted by the MOE to Suncor over the past 30 years. Suncor also argues that despite multiple opportunities since November 2004 to initiate a challenge to the Environmental Review Tribunal ("ERT") regarding the absence of a cumulative effects assessment, the Applicants have not done so. Suncor argues that the applicants had numerous opportunities to challenge the approvals that have been granted from 2004 forward. It argues that "lying in the weeds" until this point, and commencing this application as an "excuse" to undo the 2004 approvals, constitutes an abuse of process that should not be permitted by this Court. Suncor emphasizes, in particular, that its 2003 application (culminating in the Certificate of Approval) was posted on MOE's Environmental Registry so as to provide the public with statutorily required notice of the project and a 30 day comment period. No comments were received from any members of the public. It submits that the April 2010 Decision simply reinstated a production level within an envelope that had been approved in 2004 after an extensive process, and with respect to which the applicants had not commented or objected at all despite having been notified of the issues at the time.

2012 ONSC 2316 (CanLII)

[24] The applicants counter that they do not seek to shut down Suncor's entire refinery or any part of it. They submit that the relief sought is forward looking, stating that "Ada and Ron want their health to be protected when the government approves pollution". At para. 33 of their factum on the Motion to Strike the application, they state,

> [i]f Ada and Ron are successful in striking the Decision, the result will be the reinstatement of the 2008 officer's control order that limited sulphur production at the Suncor refinery to 145 tonnes per day. Although it is conceded that the officer's control order did not involve an assessment of cumulative effects, it is anticipated that Suncor will seek either a new Amending Control Order or an amendment to its certificate of approval from the Director and that the Government Respondents will then apply their discretion under the EPA in a manner consistent with the *Charter*.

The application also states that "in quashing the specific Decision at issue in this application, they seek to have such a process begin".

[25] On a motion to strike an application, the threshold is a high one. Under Rule 21.01(3)(d), the moving party must show that it is plain and obvious that the application cannot succeed, particularly where a question of constitutional or *Charter* rights is concerned: see *Miguna v. Toronto (City) Police Services Board*, 2008 ONCA 799, 2008 CarswellOnt 7120, at para. 31; *Fraser v. Canada (Attorney General)*, 2005 CanLII 47783 (ON S.C.).

[26] Moreover, such a motion may not be turned into an evidentiary disposition. Suncor submitted that as it was also seeking a stay on the basis of s. 106 of the *Courts of Justice Act*, R.S.O. 1990, c. C.43, the "plain and obvious" test as set out pursuant to Rule 21.01(3)(d) does not apply. It argued in the alternative that, even if this test applied, it had met the test.

[27] The test for a stay is also a high threshold to meet: see, e.g., *Miguna*, at para. 21; *Certified General Accountants Assn. of Canada v. Canadian Public Accountability Board*, [2008] O.J. No. 194 (Div. Ct.), at para. 39; *Schreiber v. Canada (Attorney General)*, 52 O.R. (3d) 316 (C.A.), at para. 4, leave to appeal refused at [2002] S.C.C.A. No. 74.

[28] As I advised the parties in the course of the hearing, I am not satisfied that grounds for striking the application have been made out. The application on its face confines the review application to the April 2010 Decision, submitting that the Decision infringes the applicants' s. 7 *Charter* rights to life, liberty and security of the person and their equality rights pursuant to s. 15 of the *Charter*. It seeks declarations under s. 24(1) of the *Charter* with respect to both, and an order setting aside the Decision. It also submits that the Decision violated the applicants' rights to procedural fairness in that it was made without notice.

[29] In the alternative, the application seeks an order quashing the Decision on the basis that the Director lacked jurisdiction under the EPA, and in the further alternative, that his failure to require an assessment of cumulative adverse health effects of pollution when making the Decision was unreasonable.

2012 ONSC 2316 (CanLII)

[30] Initially, the applicants also sought an order under section 52 of the *Constitution Act, 1982*, Sched. B to the *Canada Act 1982* (UK), 1982, c.11, declaring that certain sections of the EPA are inoperative "in so far as they allow for the additional discharge of contaminants to air in Chemical Valley absent an assessment and minimization of the cumulative effects of pollution on the Applicants' health." The application has now been amended to exclude this claim, apparently in recognition of the fact that such relief is not available on an application for judicial review. As will be discussed further below, the evidentiary record was filed before the amendment to the application was made.

[31] The amended application, without the s. 52 claim, does not necessarily amount to a collateral attack upon earlier approvals or decisions apart from the April 2010 Decision. In oral argument, Mr. Duncan for the applicants conceded that it is not open to them to challenge the regulatory regime on a judicial review application, and that they are only entitled to attack the exercise of the decision making power in April 2010.

[32] The April 2010 Decision permitted a 25% increase in sulphur production by Suncor's sulphur plant, though within the envelope which had been approved in 2004. It also became clear in argument that there was some confusion in the applicant's materials concerning the relationship between this increase and the overall production at the oil refinery. The only evidence in the materials filed by the parties on this issue is that the increase in sulphur production had no effect on the overall production levels of the refinery, but only on the cost of production, because with a higher sulphur production, lower quality (cheaper) crude may be used in the process. The application itself does not distinguish clearly between sulphur plant production and overall refinery production. Suncor submitted that all the emissions from its refinery had been approved previously and should not be subject, in effect, to renewed scrutiny. It argues that a cumulative effects assessment, which considers previously existing emissions would necessarily undermine earlier approvals. It cited the references in the application and the evidence to previously approved chemical emissions, such as benzene, as support for its argument that this is really a collateral attack.

[33] This is not, in my view, a basis for striking the application. It remains open to the applicants to challenge the 2010 Decision approving an increase in sulphur production, and to argue that their ss. 7 and 15 *Charter* rights were violated by the failure to consider the cumulative effects of that increase. It may well be that some of the grounds in the application which related to chemicals not affected by the Decision will not be made out, but that is not a basis for striking the application at this preliminary stage. As will be discussed below, evidence filed that is irrelevant to the proper scope of the application as it relates to the Decision increasing the sulphur production may be struck, either at this stage or by the panel hearing the application on its merits. That does not, however, render the application as a whole a collateral attack or an abuse of process.

[34] Suncor argues, in effect, that any cumulative effects assessment would reopen earlier approvals because it by definition looks at emissions already in the air, which have already been approved. This is a question that should, in my view, be left to the panel hearing the application as it is very closely related to the merits of the application.

2012 ONSC 2316 (CanLII)

[35] The motion to strike the application is dismissed.

II. MOTION TO STRIKE AFFIDAVIT EVIDENCE

[36] In support of the application, the applicants have filed five volumes of application materials, containing 13 affidavits, including the affidavits of Ada Lockridge, Ronald Plain, Wilson Plain, Dr. Elaine Macdonald, Dr. Michael Gilbertson, William M. Auberle, Dr. Henry S. Cole, Dr. Peter Infante, Dr. Margaret Keith, and Dr. David Carpenter.

[37] Both respondents take issue with much of the evidence filed. To indicate the scale of this motion, one or both respondents take issue with approximately 86 paragraphs of Ms. Lockridge's 226 paragraph affidavit, some 71 of Ronald Plain's 162 paragraph affidavit, and some 57 paragraphs of Wilson Plain's affidavit. The parties very helpfully filed charts with the court providing easier reference to the challenged portions and cross-referencing the grounds upon which they challenge them.

[38] The respondents argue that portions of, or in some cases the entirety of, these affidavits contain evidence that goes beyond the scope of the decision at issue and are therefore irrelevant to these proceedings. They also argue that portions of the affidavits are also inconsistent with the rules of evidence. The Government respondents argue that the offending portions of the evidence filed should be struck.

[39] Suncor submits that the deficiencies with the affidavits are so numerous that rather than excising the problematic portions of the Affidavits, they should be struck out in their entirety.

[40] The respondents submit that much of the evidence filed should be struck for the following reasons:

(a) **Irrelevance**: The respondents argue that much of the evidence has no bearing upon the facts at issue in the application. More particularly, the applicants have filed irrelevant evidence in support of their application that was not before the Director when making the April 2010 Order, that is beyond the scope of the Director's decision-making power under the EPA and that impugns contaminants that were not addressed by the April 2010 Order. This irrelevant evidence has no probative value, and is plainly prejudicial.

(b) **Hearsay**: The respondents submit that much of the evidence contains hearsay statements related to highly contentious matters from unidentified individuals, and double hearsay statements that are inadmissible under any circumstances.

(c) **Unqualified opinion evidence**: The respondents submit that some of the evidence is opinion evidence from unqualified lay witnesses, which is plainly inadmissible.

(d) **Argument and speculation**: The respondents also submit that much of the evidence is argumentative and speculative in nature, and therefore, inadmissible.

2012 ONSC 2316 (CanLII)

[41] The applicants make a number of arguments in response. First, they submit that the respondents' position on relevance is overly narrow in light of the fact that the application is focused on the failure to consider the cumulative impact of the emissions approved in the April 2010 Decision. The existing state of the air quality prior to the 2010 Decision is relevant and necessary to any assessment of the cumulative effect of an additional or proposed emission. Second, they argue that the questions of admissibility are best left to the panel hearing the Application to determine in light of the complete record. Third, they take issue with the substance of the evidentiary arguments raised by the respondents.

[42] Despite their position on this, the applicants have agreed to modify certain portions of the affidavits in response to the objections raised by the respondents.

[43] Given the volume of material in issue, the parties were agreed before me that I would deliver a decision relating to the categories of evidentiary issues, with illustrative examples on the various points.

[44] The first issue to be considered is the extent to which it is appropriate that a motions judge make such determinations.

Sierra Club and case law

[45] The respondents submit that this case falls squarely within the ambit of the decision in *Sierra Club v. Ontario*, 2011 ONSC 4086, [2011] O.J. No. 3071 (Div. Ct.). In the circumstances of this case, in which the applicants have filed five volumes of material, including 13 affidavits, and in which they seek broad-ranging constitutional relief, the respondents argue it would be just and appropriate for this Court to strike the impugned portions of the record on this preliminary motion. The respondents submit that, pursuant to *Sierra Club*, a failure to define the appropriate evidentiary case that the respondents must meet, and thus to define the appropriate record, encourages the proliferation of collateral issues, and can result in unnecessarily complicated, expensive and lengthy proceedings. It is preferable for such issues to be decided at a preliminary motion so as to properly define the issues and record prior to the hearing of the application for judicial review.

[46] On the other hand, the applicants argue that all the evidentiary issues raised by the respondent are issues best left to the panel hearing the application. They submit that the *Sierra Club* decision does not apply to the present case, because that case involved an administrative law challenge where the applicants had sought to file evidence that was not before the decision-maker at first instance. The applicants argue because this Application raises a *Charter* challenge, the rules of evidence are much different and broader, and thus, *Sierra Club* is essentially inapplicable.

[47] The respective positions of the parties reflect the two principles which run through the jurisprudence on the subject. On one hand, courts are generally reluctant to deal with issues of admissibility and relevance of evidence in advance of the hearing on the merits: see *Hanna v. Attorney General for Ontario*, 2010 ONSC 4058, [2010] O.J. No. 3081 (Div. Ct.); *Ontario Federation of Anglers & Hunters v. Ontario (Ministry of Natural Resources)* (2002), 211 D.L.R.

2012 ONSC 2316 (CanLII)

(4th) 741, 2002 CanLII 41606 (C.A.), at paras. 49 and 53; *876502 Ontario Inc. v. I.F. Propco Holdings (Ontario) 10 Ltd.* (1997), 37 O.R. (3d) 70 (Gen. Div.); *Elementary Teachers' Federation of Ontario v. Ontario (Minister of Labour),* [2008] O.J. No. 662 (Div. Ct.) at paras. 22-23.

[48] On the other hand, this court has recently endorsed the practice of resolving issues about the admissibility of affidavit evidence before a motions judge prior to the hearing before the Divisional Court panel. In *Sierra Club*, the Court stated, at paras. 7 to 8,

> [w]e 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 (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.
>
> 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.

[49] In *Chopik v. Mitsubishi Paper Mills Ltd.* (2002), 26 C.P.C. (5th) 104 (ON S.C.), Justice Shaughnessy struck out, on a preliminary motion, a number of paragraphs from two affidavits submitted in support of a motion for certification under the *Class Proceedings Act, 1992*, S.O. 1992, c. 6, on the basis that responding to the irrelevant evidence would amount to needlessly wasted resources:

> Where it is clear in law that evidence is inadmissible, to leave the evidence on the record is embarrassing and prejudicial to the fair hearing of the motion or application. A party should not be put to the needless expenditure of time and resources in responding to evidence which can have no impact on the outcome of the proceeding. [at para. 26.]

[50] These two principles, considered within the context of the present case, are by no means irreconcilable. Defining the record appropriately in advance of the hearing enhances the panel's ability to determine the merits, and is thus in the interests of justice. As I will discuss below, there is material contained within the affidavit material that is clearly inadmissible and should be struck. On the other hand, this court must take care not to usurp the role of the panel in

2012 ONSC 2316 (CanLII)

determining the merits. In case of doubt concerning the admissibility of affidavit material filed, it should not be struck.

[51] I do not agree with the applicants that the fact that there are *Charter* claims advanced in the present case undermines the position articulated in *Sierra Club*. The fact that an applicant advances *Charter* arguments (or natural justice arguments) may well affect the admissibility of particular sorts of evidence, such as, for example, evidence not before the original decision-maker: see *Hollinger Farms No. 1 Inc. v. Ontario (Minister of the Environment)*, [2007] O.J. No. 2405 (Div. Ct.). But this does not undermine the principles articulated above. For example, improper opinion evidence that is clearly inadmissible is not rendered admissible because the underlying application raises *Charter* issues.

[52] The sheer volume of evidence in an application such as this one increases the importance of having a properly defined record for the reasons set out in *Sierra Club*, as quoted above. I do not agree with the applicants' submission that *Sierra Club* is inapplicable to this matter because there was no hearing held in the present matter. The principle that a record should be appropriately defined before the hearing is particularly important in an era of limited resources within the judicial system as well as the high cost of litigation to the litigants. Having said this, the parallel principle is that evidence should not be struck at this stage unless it is clearly inadmissible. These two principles will guide the following analysis.

[53] Suncor argues that much of the evidence is not admissible on the application for judicial review because it was not before the initial decision maker:

> The summary nature of applications for judicial review dictates that, in general, evidence should be limited to the information that was before the original decision-maker or which the decision-maker could have taken into consideration, except where necessary to prove error going to jurisdiction that cannot be proved on the record.
>
> In addition to evidence that was not before the original decision-maker, expert reports and studies that post-date the decision under review are inadmissible. Courts have furthermore emphasized that they are not academies of science which seek to provide a forum to debate environmental science:
>
> > It is not the role of the Court in these proceedings to become an academy of science to arbitrate conflicting scientific predictions, or to act as a kind of legislative upper chamber to weigh expressions of public concern and determine which ones should be respected. [citations omitted.]

[54] The difficulty with Suncor's argument on this point is two-fold. First, the nature of the applicants' submissions fall within to the exception to the general rule that evidence not before the initial decision maker is not admissible on an application for judicial review. The applicants assert that the Decision breached their ss. 7 & 15 *Charter* rights. As Dambrot J. recently stated in *AlGaithy v. The University of Ottawa*, 2011 ONSC 5879, [2011] O.J. No. 4479 (Div. Ct.), at para. 29,

2012 ONSC 2316 (CanLII)

> …as with an allegation of a breach of natural justice, affidavit evidence must also be permissible to supplement the record to demonstrate a validly raised allegation of constitutional error (see *Rafieyan v. Minister of Citizenship and Immigration*, 2007 FC 727, [2007] F.C.J. No. 974 at para. 20). I emphasize that the constitutional issue must be validly raised. The mere labelling an issue as a constitutional one will not of itself open the door to the admission of otherwise inadmissible evidence.

[55] Second, as the applicants point out, they did not have prior notice of the decision and could not have put this issue before the Director.

[56] In my view, the *Charter* and procedural fairness arguments are at the core of the applicants' application and are arguments that must be assessed by the panel hearing the application. I would not strike any of the evidence on the sole basis that it was not before the decision maker at this point, because to do so would risk pre-judging the merits of the application.

Relevance

[57] The largest and most wide-ranging challenge to the evidence filed is based on the submission that much of it is irrelevant. The respondents challenge dozens of paragraphs of the Lockridge and Plain affidavits, as well as the entire affidavits filed by Dr. Michael Gilbertson, Dr. Elaine Macdonald and Dr. Margaret Keith on this ground. Many paragraphs are also challenged on other grounds.

[58] With respect to the "hybrid" affidavits of Drs. Gilbertson, Keith and Macdonald, the central objection is that they constitute improper expert opinion and should be struck in all or in part on that basis alone. I will address the hybrid affidavits below in relation to improper expert opinion evidence.

[59] With respect to Ada Lockridge's affidavit, the Government respondents assert as follows at para. 18 of their factum:

> In her affidavit, Ms. Lockridge gives evidence on issues that are irrelevant to this judicial review, including: (a) the feelings of individuals on reserve other than the applicants (paragraphs 25, 71, 177); (b) sources of spills and pollution other than those which are the subject of the impugned decision (which are irrelevant to the determination of this application for the reasons set out below at paras. 45-47 and 53-56) (paragraphs 33, 43, 52, 152, 167, 179, 186); (c) personal health conditions unrelated to the emissions or facility at issue (paragraphs 89, 90, 102, 104-9, 129, 130, 132, 135); (d) personal health conditions and community statistics unrelated to air quality (paragraphs 89, 90, 102, 104-9, 132, 135); (e) the availability of social services on reserve (paragraph 100); (f) the effects of generalized pollution on animals, plants, water, and soil (paragraphs 153, 154, 161, 164, 165, 167-9,

2012 ONSC 2316 (CanLII)

> 217); and (g) the traditional activities and practices of the community (paragraphs 152, 153, 155, 158, 160, 162, 171-4, 176).[1]

[60] With respect to Ronald Plain's affidavit, the Government respondents submit as follows at para. 23 of its factum:

> In his affidavit, Mr. Plain gives evidence that is irrelevant to this judicial review, including: (a) the community's reaction to sirens and other views or feelings of individuals on reserve other than the applicants (paragraphs 20, 79, 92); (b) generalized exposure to pollutants other than those at issue in the impugned decision (which are irrelevant to the determination of this application for the reasons set out below at paras. 45-47 and 53-56) (paragraph 32); (c) personal health conditions unrelated to the emission source at issue (paragraphs 35, 48, 93, 100, 101, 114); (d) personal health conditions and community statistics entirely unrelated to air quality (paragraphs 35, 93, 100, 101); (e) the availability of social services on reserve (paragraph 42); (f) the traditional activities and practices of the community (paragraphs 72, 74-77); (g) the manner in which individuals in the community make plans and lock doors (paragraph 78); (h) the community's trust in outsiders (paragraph 80); (i) the number or proportion of older people on reserve (paragraph 81); (j) educational experiences of his father (paragraph 86); (k) historical land disputes (paragraphs 87-91); (l) funding sources for environmental workers (paragraphs 98, 99); (m) sources of spills and pollution other than those which emerge from the emission source at issue (paragraphs 102-4, 111); (n) an unrelated road blockade (paragraphs 109, 110); and (o) his opinion as to the government's methods of regulation (paragraphs 148-50, 152).[2]

[61] Wilson Plain, who is not a party to the application, also filed an affidavit. The Government respondents submit that paras. 9-17, 20-4, 32, 35-40, 44-6, 48-50, 52, 54, 63-5, 70-4, 76-8, 81, 85, 91, 94, 95, and 99 are irrelevant to the application, stating at para. 28 of their factum that,

> [i]n his affidavit, Mr. Plain gives evidence that is irrelevant to this judicial review, including: (a) sources of spills and pollution other than those which emerge from the emission source at issue (paragraphs 32, 52, 81); (b) PCBs, benzene emissions, and other contaminants which are unrelated to the decision at issue on this application (paragraphs 39, 63-5, 73, 74); (c) his personal health conditions, including those unrelated to the emission source at issue (paragraphs 63, 64, 91);

---

[1] Suncor takes issue with generally, though not completely, the same paragraphs. Suncor challenges paras. 25, 33, 43, 52, 71, 89, 90, 100, 102, 104, 105-109, 122, 129, 130, 132, 135, 136, 152, 153-55, 158, 160-62, 164-65, 167-69, 171-74, 176-77, 179, 186 and 217 of Ms. Lockridge's affidavit.

[2] Suncor objects to paras. 20, 32, 35, 42, 48, 72, 74, 75, 76-94, 98-104, 108-111, 114, 127 and 148-52 on the ground of relevance.

2012 ONSC 2316 (CanLII)

> and (d) the health conditions or diagnoses of others in the community, including conditions and statistics unrelated to air quality (paragraphs 65, 70-2, 76).[3]

[62] In addition to the affidavits filed by the applicants and Wilson Plain, the applicants filed a number of affidavits by scientists. As will be discussed below, the respondents challenge some or all of these on a number of grounds in addition to relevance, submitting in particular that they constitute improper expert opinion evidence, at least in part.

[63] The applicants also filed an affidavit from Dr. Elaine Macdonald, a scientist employed by Ecojustice Canada. The Government respondents challenge the relevance of some of her affidavit as follows at para. 34 of their factum:

> Dr. Macdonald also gives evidence on issues that are, as discussed below at paras. 45-47 and 53-56, irrelevant to this judicial review, including: (a) emissions of "toxics" (paragraph 33) (b) sex ratio disparities (paragraph 34); (c) emissions of PM2.5, benzene and other volatile organic compounds (VOCs) that are unrelated to the decision being reviewed or the emission source at issue (paragraphs 39, 45, 46, 51); (d) air pollution standards under Regulation 419/05 (paragraphs 51, 58-60); and (e) proposed certificates of approval for facilities other than the one at issue (paragraph 51).[4]

[64] Dr. Michael Gilbertson, a biologist filed another affidavit. The respondents object to this affidavit on the ground that it contains improper expert opinion, and that, to the extent that it provides evidence within his personal knowledge, such evidence is irrelevant to the issues in this judicial review application. By way of example, the Government respondents submit that his description of his interpretation of the 1996 report on soil and sediment, and the content of that report are irrelevant to the decision at issue in this application, which concerns a 2010 decision in respect of air emissions. Moreover, they argue, there is no allegation of any link between the sulphur dioxide emissions that were the subject of the 2010 Decision and the sex ratio disparities alleged by Dr. Gilbertson at paras. 12, 13, 16, 18 and 19 of his affidavit.[5]

[65] The application record also contains an affidavit from Dr. Margaret Keith. Again, the respondents submit that her affidavit should be struck in its entirety for reasons similar to those it advances in the case of Dr. Gilbertson. With respect to the relevance issue, the Government respondents submit at para. 41 of their factum that,

---

[3] Suncor objects to paras. 9-17, 20-24, 32, 35-40, 44-46, 48-50, 52, 54, 63-65, 70-74, 76-78, 81, 85, 91, 94, 95 and 99 on the ground of relevance.

[4] Suncor takes issue with paras 33-34, 39, 45-46, 51 and 58-60 on the grounds of relevance.

[5] Suncor submits that the entirety of the Gilbertson affidavit should be struck on the basis that it constitutes improper opinion evidence, and is in any event, irrelevant to the issues in this judicial review application.

2012 ONSC 2316 (CanLII)

> [t]o the extent that Dr. Keith provides fact evidence within her personal knowledge, this evidence is not relevant to the decision at issue in this judicial review. Historical emissions of benzene from sources other than the relevant plant (paragraphs 4, 7), and discussions with community members about their health concerns (paragraphs 7-10, 12, 22) are not relevant to the determination of this application. Moreover, there is no allegation of any link between the sulphur dioxide emissions (the subject of the decision being reviewed here) and the sex ratio disparities alleged by Dr. Keith (paragraphs 12, 28-31, 34).

[66] The applicants have also put forward a series of expert reports regarding industrial emissions, their effect on air pollution, and the effects of pollution on human health. These include the reports of William M. Auberle, Dr. Henry S. Cole, Dr. Peter Infante and Dr. David Carpenter. For the purposes of this motion the respondents do not challenge the qualifications of the witnesses that the applicants have put forward as experts. However, they submit that significant portions of all of these experts' reports should be struck on the basis that they provide evidence that is not relevant to the decisions at issue or the determination of the application for judicial review.

The Respondents' Submissions on Relevance

[67] The respondents submit that much of the evidence filed is irrelevant to this application as a judicial review of the April 2010 Decision. The overly broad evidence results largely, they submit, from two factors. First, they argue, supported by the uncontested affidavit of Dr. Peter Lynch, Director of Suncor's Environment, Health and Safety Department, that the application and much of the evidence filed in support confused sulphur production levels with the overall processing capacity of the refinery. He states at para. 16 of his affidavit that,

> …there is <u>no</u> change in the volume of the product produced by the Sarnia Refinery (i.e. gasoline, diesel and jet fuels) despite variances in the level of sulphur production from 145 tonnes per day to 180 tonnes per day. The only change is the blend of crude oils processed, which vary only by their sulphur content. For example, if Suncor was granted a notional increase in sulphur processing capacity from 145 tonnes per day to 180 tonnes per day, there would be no corresponding increase in the amount of fuel products created. Rather, the increase in sulphur processing capacity would enable Suncor to utilize more sour crude. Conversely, if the Ministry of the Environment ("MOE") ordered Suncor to process only 145 tonnes of sulphur per day, there would be no corresponding decrease in the amount of fuel products created. Suncor would instead purchase more expensive, sweeter crude.

[68] Thus, the respondents submit, only evidence relating to the increase in sulphur production, as opposed to overall product production by the plant, is relevant to this application. They concede that the evidence filed contains some evidence indicating that increase in sulphur production authorized by the 2010 Decision could increase emissions of sulphur dioxide and hydrogen sulphide. However, there is no evidence whatsoever to indicate that the increased

2012 ONSC 2316 (CanLII)

sulphur emissions would increase other emissions, such as benzene. Moreover, they submit, there is no evidence on the record to suggest that the approved emissions would have synergistic or cumulative effects with other existing emissions. They argue, therefore, that only evidence relating to the effects of sulphur dioxide and hydrogen sulfide could be relevant to any consideration of cumulative effects of this application. Accordingly, for example, Ada Lockridge's reference to a "loss of boys" i.e., a skewed sex ratio on the reserve suggesting that this is caused by pollution exposure (see para. 109 of her affidavit), is irrelevant to this application in the absence of any casual link between the April 2010 Decision and this pre-existing harm, or indeed, any such harm or risk of harm in evidence.

[69] Second, the respondents submit that because the evidence was filed before the application was amended to delete the s. 52 claim, the evidence includes evidence that is irrelevant to the more narrow judicial review challenge to the 2010 approval itself. They submit, in effect, that the applicants may not indirectly challenge the regulatory framework through the guise of a judicial review application, and that it is therefore appropriate for this court to strike any evidence that is not relevant to the properly scoped issue. They emphasize that the *Charter* relief sought on a judicial review application must relate to the purported *exercise* of statutory power and not to the statutory power itself, citing *Re Service Employees International Union, Local 204 and Broadway Manor Nursing Home et al.*, [1984] O.J. No. 3360 (C.A.), *Keewatin v. Ontario (Minister of Natural Resources)*, [2003] O.J. No. 2937 (S.C.), and *Falkiner v. Ontario (Ministry of Community and Social Services)*, [1996] O.J. No. 3737 (Gen. Div.), in support of this point.

[70] The respondents submit that, in order to establish that their s. 7 or 15 *Charter* rights have been violated in this case, the applicants must establish a causal connection between the harm or risk of harm asserted and the 2010 Decision. As the evidentiary record indicates that this decision could only have affected sulphur dioxide and hydrogen sulphide, and does not suggest any synergistic effects of these particular emissions on other emissions, evidence about the health effects of benzene or the general state of pollution in the area are entirely irrelevant to this application and should be struck.

[71] The respondents argue, accordingly, that portions of the applicants' and Wilson Plain's affidavits that describe existing pollution are irrelevant to this application as they have nothing to do with the 2010 Decision.

[72] At para. 43 of their factum, the Government respondents summarize the basis of their position (which is shared by Suncor) that much of the expert evidence should similarly be struck as irrelevant:

> In particular, the applicants' experts provide extensive evidence regarding the emission of, and the health effects of benzene, 1,3-butadiene, other volatile organic compounds (VOCs) and PM2.5 in the Sarnia region. Dr. Infante's report, for instance, deals exclusively with the potential link between benzene exposure and disease, without any evidence regarding the nature of exposure in the applicants' community or providing any link between the decisions at issue and

2012 ONSC 2316 (CanLII)

benzene emissions or the effects thereof. None of the applicants' evidence provides such a link.

The Applicants' Submissions

[73] The applicants acknowledge that the application as amended is limited to a challenge of the Director's decision. They argue, however, that the question of relevance turns on the issue of whether he was required to conduct a cumulative effects assessment and if so, of what. These, they submit, are questions that go to the merits, and excluding such evidence (relating, for example, to existing cultural effects of pollution in the area) effectively prejudges the merits and risks creating a record that does not reflect the applicants' views on the issues.

[74] The applicants also argue that the risk of harm they assert in their ss. 7 and 15 *Charter* claim is the risk of exacerbating the preexisting harms created by pollution on the area. The state of "Chemical Valley" before 2010, they submit, is relevant to this issue and goes to the argument of fundamental justice because, the applicants argue, it is contrary to the principles of fundamental justice to approve further emissions without a cumulative effects assessment.

[75] In addition, they cite *Gosselin v. Quebec (Attorney General)*, 2002 SCC 84, [2002] 4 S.C.R. 429 in support of its argument that this evidence is necessary to have in the record to set the context for their s. 15 argument that the 2010 Decision created a disparate impact upon the applicants.

Analysis of Relevance

[76] There are a number of general points to be made at the outset. First, I am satisfied that there was some confusion on the applicants' part between the production of sulphur and the overall production by the refinery. The uncontested evidence before the court in the application record is that the 2010 Decision affected the former and not the latter. In addition, the evidence indicates that while this increase might affect production of sulphur dioxide and hydrogen sulphide in some circumstances, there is no evidence that the 2010 Decision would have synergistic effects on any other contaminants such as benzene.

[77] Having said this, however, I am not satisfied that any references to preexisting pollution and its effects on those living in the area should be struck at this stage.

[78] With respect to its s. 7 claim, the applicants must establish that the 2010 Decision has created a risk to their physical or psychological health, or affects their ability to make fundamental life choices. They must also establish that such deprivation took place in a manner that did not conform to the principles of fundamental justice. They assert that the exclusion of the applicants from the decision-making process, the consequent deprivation of a right to be heard, and the failure to consider cumulative effects constituted a violation of the principles of fundamental justice.

[79] With respect to s. 15, the applicants must establish that the Director's Decision has had a disproportionate impact on the applicants on the basis of an enumerated or analogous ground,

2012 ONSC 2316 (CanLII)

and that the disproportionate impact has created a disadvantage by perpetuating historical disadvantage.

[80] For the reasons advanced by the respondents in this motion, it may well be the case that the applicants are unable to establish any causal connection between the 2010 Decision and the harms or risks of harms asserted that will be sufficient to "trigger" ss. 7 and 15 of the *Charter*. I agree with the respondents that only evidence relating to the 2010 Decision and any synergistic effects of the increase in sulphur production authorized by it are relevant for that purpose, and not any earlier approvals or preexisting contaminants in the absence of evidence of synergistic effects with the increased level of sulphur production.

[81] However, if a panel were to determine that the exercise of statutory power did create a harm or risk of harm that triggered the applicants' *Charter* rights, the broader context of the disproportionate impact on the applicants as members of the Aamjiwmaang community would be an issue. A decision to exclude all such evidence would thus risk prejudging the merits of the application relating to the general levels of pollution and its effects on the area, the applicants and their community. I would not, for this reason, strike any of the paragraphs of the applicants' or Wilson Plain's affidavits on the basis of relevance. Because these affidavits are filed by the applicants and Wilson Plain who is also a resident of the area and a member of the Aamjiwmaang community, their perceptions of preexisting conditions may be relevant to the impact of the 2010 Decision upon them and, therefore, to the disparate impact argument. In these circumstances, it would be problematic to separate these issues from portions of the affidavits that might be clearly irrelevant.

[82] However, as will be discussed below, some passages of these affidavits must be struck on the basis of improper opinion evidence or unattributed hearsay.

[83] The expert's reports are reviewed below. With the exception of Dr. Infante's report, which I would strike in its entirety, portions of all of them are relevant or at least potentially relevant to this judicial review application. All of them contain portions that are not confined to the issues of this application as "scoped". Having said that, however, I have determined not to strike those portions so that the panel may consider the full reports within the context in which they were actually prepared. The panel may conclude that it is appropriate to strike or disregard various portions of these reports, but in my view, it should be able to consider the context of the reports as originally drafted in making such determinations.

Dr. Auberle's Report

[84] The respondents object to Dr. Auberle's report to the extent that it opines on the emissions of benzene and 1,3 butadiene and other pollutants which are not in issue in this application. He does, however, in the course of his brief report, articulate a relevant question, which is, "is the decision to allow Suncor to increase its production of sulphur likely to increase pollutant emissions from the facility?". He discusses the emissions of sulphur dioxide and hydrogen sulphide in the course of sulphur processing, which is clearly relevant to this application. Paragraphs 2.2 and 2.3 refer to pollutants emitted from the facility "during regular

2012 ONSC 2316 (CanLII)

operations" but does not tie them (with the exception of nitrogen oxide and ultra-fine particulate matter) to sulphur production. He also opines that "current regulatory practices do not address such emissions and effects adequately".

[85] While this report may be overly broad in light of the issues on this application, I would be concerned that striking portions of it could affect the application judge's ability to properly assess it and determine the appropriate weight to be attributed to the relevant parts of it. The respondents are, of course, entitled to make full argument on these issues to the panel hearing the application, but it would, in my view, be premature to strike it at this point.

Dr. Cole's Report

[86] Similarly, Dr. Cole's report clearly appreciates the fact that the impugned decision affected sulphur production. His report is critical of the general regulatory framework, and thus his report is overly broad. One of the questions he addresses is whether "Suncor's emissions have increased the exposure of Applicants and other people residing in the Aamjiwmaang First Nation area to elevated exposures of pollutants known to cause adverse health effects". He refers to benzene and other chemicals. It is not clear from his report whether this comment relates to sulphur production or overall refinery production. Striking this statement could distort the evidence, and it should therefore remain at this point. His report also reviews general sources of air pollution in relation to the Aamjiwmaang First Nation community. As discussed above, this could be relevant to disparate impact issues.

[87] It would be premature to strike any part of this report. This is a matter that should be left to the panel to consider in the context of the issues properly before it.

Dr. Infante's Report

[88] In my view, Dr. Infante's report is in a different category. It concerns the relationship between leukemia and benzene. This report does not add anything to the other reports and has no link whatsoever to the 2010 Decision. In my view, it is irrelevant to this application and should be struck.

Dr. Carpenter's Report

[89] This report considers pollution and its effects in the Sarnia/Aamjiwmaang community in comparison to the average Ontario community. It also opines on Ontario standards for various contaminants (including sulphur dioxide) relative to those existing in the United States.

[90] Again, while the scope of the report appears to be broader than that which is relevant to the application, in that it discusses pollutants that do not seem to be affected by the 2010 Decision, significant portions of it relating to general pollution in the area could be relevant to the disparate impact argument and it would thus be premature to strike it at this point. While, in my view, the affiant's opinions on the adequacy of the regulatory requirements in Canada relative to those existing in the United States are clearly irrelevant to the judicial review of the

2012 ONSC 2316 (CanLII)

2010 Decision, the decision about deleting portions of it should be left to the panel to determine in the context of the issues properly before it.

The reports of Dr. Jackson, Dr. Reimer and Dr. Mitchell

[91] Suncor submits that these reports are irrelevant to the Decision under review and should be struck.

[92] While these reports, which address anthropological, cultural and psychological effects of pollution upon First Nations peoples, do not concern the harm or risk of harm allegedly caused by the Decision under review, they could be relevant to a consideration of the impact of any harm that a court found to have been created by the 2010 Decision. They may be relevant to the s. 15 disparate impact argument. A decision to exclude this evidence at this stage would prejudge the merits of this application and is therefore premature. Accordingly, I would not strike them at this stage.

Improper Opinion Evidence

The Hybrid Affidavits Dr. Macdonald, Dr. Keith and Dr. Gilbertson

[93] The applicants have also filed a number of affidavits from scientists, which are not proffered as expert evidence. These include the affidavits of Dr. Macdonald, Dr. Keith and Dr. Gilbertson. I conclude that these reports should be struck in their entirety. In essence, these affidavits are proffered for the scientific value of the opinions they express. They do not qualify as expert evidence and should therefore not be admitted. In addition, portions of the applicants' and Wilson Plain's affidavits constitute improper opinion evidence and should be struck.

[94] Opinion evidence may only be tendered through the evidence of a properly qualified expert. Unqualified expert opinion is impermissible and should be struck: see *Bedford v. Canada (Attorney General)*, 2010 ONSC 4264, [2010] O.J. No. 4057 (S.C.), at para. 101; *Southcott Estates Inc. v. Toronto Catholic District School Board*, [2009] O.J. No. 428 (S.C.), at para. 110, varied on other grounds, 2010 ONCA 310; *R. v. Mohan*, [1994] 2 S.C.R. 9, at paras. 17 and 27; *Rules of Civil Procedure*, R.R.O. 1990, Reg. 194, R. 4.1.01(1).

[95] The importance of this principle and the role of the court as gatekeepers to exclude such improper evidence was recently underlined in the course of the inquiry by Mr. Justice Goudge concerning the forensic pathology work of Dr. Charles Smith.[6] At pp. 499-500 of his report, Goudge J.A. noted the importance of trial judges determining the scope of admissible expert evidence, including by defining the precise subject area of expertise for which a witness is qualified to give evidence and ensuring that expert evidence is only admitted within the narrow scope for which the witnesses has been properly qualified:

---

[6] Ontario, Inquiry into Pediatric Forensic Pathology in Ontario, Report: Policy and Recommendations, vol. 3 (Toronto: Queen's Printer, 2008) ("The Goudge Report").

2012 ONSC 2316 (CanLII)

> A final outcome from the admissibility process is a clear definition of the scope of the expertise that a particular witness is qualified to give. As discussed in the earlier part of this chapter, it will be beneficial to define the range of expertise with as much precision as possible so that all the parties and the witness are alerted to areas where the witness has not been qualified to give evidence. . . . As I earlier recommended, the trial judge should take steps at the outset to define clearly the proposed subject area of the witness's expertise…. These steps will help to ensure that the witness's testimony, when given, can be confined to permissible areas and that it meets the requirement of threshold reliability.

[96] In my view, the entire affidavits of both Dr. Michael Gilbertson and Dr. Margaret Keith are effectively expert opinion. They are both scientists, have both done research in fields related to the claims advanced which they discuss and with respect to which they opine in their affidavits. They have not signed an acknowledgement of the expert's duty form, nor do they claim to be neutral, unbiased or non-partisan in their evidence, as required by the *Rules of Civil Procedure* and by common law principles governing the role of expert witnesses. They have taken on the role of advocates. As these witnesses are not tendered as qualified experts, their affidavits putting forward opinion evidence are improper and should be struck in their entirety: see *Rules of Civil Procedure*, R. 53.03(2.1); *National Justice Compania Naviera S.A. v. Prudential Assurance Co. Ltd. ("The Ikarian Reefer")*, [1993] 2 Lloyd's L.R. 68 (Q.B. (Com. Ct.)) at 81; *Sagl v. Cosburn, Griffiths & Brandham Insurance Brokers Ltd.*, 2009 ONCA 388, [2009] O.J. No. 1879, at para. 85; *Bedford v. Canada,* at paras. 100-3; *Gutbir (Litigation guardian of) v. University Health Network*, 2010 ONSC 6394, [2010] O.J. No. 4982, at paras. 21-24.

[97] Much of the affidavit of Dr. Elaine Macdonald is also expert opinion. She has not signed an acknowledgement of expert's duty form and has not claimed to be neutral, unbiased or non-partisan in her evidence. Her evidence shows that she is an advocate for the position of the applicants. As Dr. Macdonald is not qualified to provide expert opinion, the numerous portions of her affidavit where she has provided expert opinion (as set out in Schedule A to the Notice of Motion) are inadmissible and should be struck. While there are portions of her affidavit that do reflect personal experience, these portions do not add to other material already before the Court, particularly in the absence of those portions that effectively constitute improper opinion evidence.

[98] In concluding that the Report of Dr. Macdonald should be struck in its entirety, I also note that she was mistaken as to the effect of the Decision, and appears to have assumed that the increase in sulphur production also affected the overall fuel production at the Suncor refinery. This increases the risk that much of her affidavit is irrelevant to the effects of the 2010 Decision, in any event.

[99] One of the fundamental duties of the expert witness in a civil case is to provide independent assistance to the court by way of objective, unbiased opinion in relation to matters within the witness' expertise. An expert witness should not assume the role of advocate. Dr. Gilbertson, Dr. Keith, and Dr. Macdonald each provide argumentative and speculative

2012 ONSC 2316 (CanLII)

statements in their affidavits that are put forward in support of the applicants' position. While there are, as indicated above, some portions of these affidavits that do reflect personal experience, these are greatly outweighed by the potentially prejudicial effect that improper opinion evidence may have. This risk is exacerbated when the affiants are scientists as opposed to laypersons such as Ms. Lockridge, Ronald Plain, and Wilson Plain.

[100] Their evidence is inconsistent with the rules for putting expert opinion before the court and should, accordingly, be struck.

The opinion evidence of Ada Lockridge, Ronald Plain and Wilson Plain

[101] The applicants Ada Lockridge and Ronald Plain, as well as Wilson Plain, another fact witness, provide opinion in their affidavits on a wide range of topics which relate in particular to the effects of pollution from the refineries on their community. These witnesses are not qualified to provide expert opinions on these topics. Their opinion evidence is inadmissible and should be struck. While Ada Lockridge, for example, may give evidence as to studies she has participated in and what she has done, she may not give expert evidence as to the results or import of such studies. For example, at para. 79 of her affidavit, she refers to her involvement in some investigation into the sex ratio issue:

> In our study, we recognized that further study was necessary to pin-point the cause of the skewed birth ratio and to further study our findings but we pointed out that an issue existed and that maybe pollution could be the cause.

[102] This paragraph constitutes improper expert opinion, as does a considerable part of the Lockridge affidavit relating to empirical work that Ms. Lockridge has been involved with. It goes far beyond a statement that Ms. Lockridge was aware of and concerned about the sex ratio issue and worried about the cause. The applicants have agreed to delete the following passage which was the final sentence of para. 79:

> Despite the need for additional study, my own personal view given the comparison between Aamjiwmaang and the control group is that there is only one difference in lifestyle and that is the fact that we live in Chemical Valley and its pollution.

[103] Having said that, the applicants' evidence relating to the fear or uncertainty as to, for example, cancer rates and statements like "I worry that…", etc., are potentially relevant to harm or perception of harm and to disparate impact arguments. Similarly, many of the paragraphs the respondents object to as "unqualified opinion" are arguably relevant to psychological impact of the Decision. One such example is found at para. 23 of Ronald Plain's affidavit:

> The effects of long-term cumulative exposure to pollution from all the different exposure to pollution from all the different sources in Sarnia may be killing me slowly like death by a thousand cuts, but I can't point to anyone single source of pollution or type of pollution that has to stop to protect my health. The fact is that all of the emissions contribute in a cumulative manner to the health risks to which

2012 ONSC 2316 (CanLII)

> my family, friends, and I are exposed. Adding to the existing pollution burden in our community increases these risks. Not knowing what specifically is being emitted and whether the air pollution poses serious health risks at a given time or location is hugely stressful. Suncor's increase in production which is at issue is one of many examples.

[104] To the extent that the content in this paragraph is understood to be opinion evidence relevant to establishing the state of pollution in the area, I would agree with the respondents that it is improper. The central point of this paragraph, however, relates to the psychological effects of pollution in general and uncertainty. It is not feasible to segregate out statements that should be excluded from those that are arguably admissible, and so it is appropriate that the paragraph should remain, and the respondents may argue about the issues of admissibility and weight before the panel.

[105] Not all expressions of opinion are inadmissible on the part of lay witnesses: see *Graat v. R.*, [1982] 2 S.C.R. 819, 31 C.R. (3D) 289 at p. 305; David M. Paciocco & Lee Stuesser, *The Law of Evidence*, 5th ed., (Toronto: Irwin Law, 2008).

[106] In considering whether a lay opinion will be admitted, a judge will consider,

> …whether the conclusion is one that people with ordinary experience are able to make. Persons of ordinary experience may be able to estimate the speed of a motor vehicle, for example, but not the speed of an airplane. A judge will also consider whether the particular witness has the "experiential capacity" to form the relevant opinion. A young child will not likely have the ordinary experience needed to comment even on the speed of a motor vehicle. [Paciocco & Stuesser, at p. 187.]

[107] In my view, the affiants who reside in the area have the requisite experiential capacity to opine, for example, on matters like the apparent increase in air pollution when the wind is blowing from the refineries, subject, of course, to the rules of relevance. They do not have the requisite capacity to opine, for example, on the effects of particular contaminants on various health or environmental conditions. Such evidence may only be adduced through proper expert evidence.

[108] In sum on this issue, the evidence that is clearly improper opinion evidence should be struck from these affidavits. To the extent that the affidavits refer to fears or uncertainty about effects of pollution that may be relevant as discussed above, the issue should be left to the panel hearing the application. Similarly, not all the opinions expressed by these affiants are inadmissible as some of them are, at least arguably, within their experiential capacity.

Unattributed Hearsay Evidence

[109] In an application, an affidavit may contain statements of the deponent's information and belief with respect to facts that are not contentious, if the source of the information and the fact

2012 ONSC 2316 (CanLII)

of the deponent's belief in the information are specified in the affidavit: see *Rules of Civil Procedure*, R. 4.06(2) & 39.01(5).

[110] However, statements in affidavits for use on an application that touch on a contentious matter and do not state the source of the affiant's information and belief should be struck. It is essential to the adversarial process that evidence submitted by affiants be under oath or affirmation, and that the affiant is available to be cross-examined in order to test the reliability of the evidence. This rule is well established, and "in the face of an objection being taken the Court may not waive the irregularity": see *Cameron v. Taylor* (1992), 10 O.R. (3d) 277 (Gen. Div.), at para. 24; *Metzler Investment GMBH v. Gildan Activewear Inc.*, [2009] O.J. No. 3394 (S.C.), at paras. 33 and 50; *Ontario (Attorney General) v. Paul Magder Furs Ltd.*, [1990] O.J. No. 63 (H.C.J.), at para. 21.

[111] The applicants argue that such evidence, however, may still be admissible under the principled exception to the hearsay rule, citing *R. v. Starr*, [2000] 2 S.C.R. 144, at para. 106; *R. v. Khelawon*, [2006] 2 S.C.R. 787, at paras. 56-63.

[112] The affidavits of Ada Lockridge, Ronald Plain, and Wilson Plain contain instances where the affiants do not attribute the source of hearsay statements in respect of contentious facts. These paragraphs are set out in Schedule A to the Notice of Motion. This evidence is inadmissible, and should be struck: see *Canadian Blood Services v. Freeman*, [2004] O.J. No. 4519 (S.C.), at para. 19.

[113] In general, the respondents argue that these paragraphs should be struck on a number of grounds in addition to unattributed hearsay, such as irrelevance. For example, Ms. Lockridge states at para. 179 that,

> I remember several evacuations from Aamjiwmaang when I was young due to spills to air. I remember in the early 1970s that there was a massive spill from the Dow chemical plant, but at that time I didn't know what had been released or from where. […] That specific Dow release killed some of the workers at Suncor and burned a patch through the bush at Aamjiwmaang. People saw a haze and it was coming through their windows. Some people stayed home because they didn't have a ride or because they refused to leave. When I started doing environmental work people would tell me about incidents over the years and many people spoke about that spill from Dow as something that stuck in their minds.

Paragraph 20 from Ronald Plain's affidavit states as follows:

> The sirens scare my kids; my understanding is that they scare all the kids that go to the daycare because the sirens are right in front of the daycare. There really is no way to react to them because there is no way to know what a siren means.

[114] The respondents object to these passages on the basis that they contain unattributed hearsay relating to matters that are contentious, and that are irrelevant as well.

2012 ONSC 2316 (CanLII)

[115] At para. 38 of his affidavit, Wilson Plain provides the following statement:

> To my knowledge, only a handful of people on reserve continue to hunt animals such as deer. These activities are more and more uncommon because of concerns about contamination of animals from industrial pollution. In the past decade, several studies have been conducted of contamination levels on our land and in the reserve. We have actually been warned by our own hunters, like my brother Gerald Plain, as well as researchers following one of these studies, not to eat deer that have spots on their livers, which our own hunters were starting to find.

[116] The respondents submit, and I agree, that these passages contain improper opinion evidence as well as unattributed hearsay, and that they should be struck for this reason.

[117] The combination of the fact that these statements are unattributed hearsay and that they have nothing to do with the April 2010 Decision makes the respondents' arguments that much stronger. Although I am inclined to generally resolve questions of relevance in these affidavits, as discussed above, in favour of the applicants, the combination of factors satisfy me that the paragraphs set out in Schedule A to the Notice of Motion in relation to unattributed hearsay should be struck.

Speculative evidence

[118] The respondents submit that a number of paragraphs of the affidavits of Ada Lockridge, Ronald Plain, Wilson Plain and Dr. Elaine MacDonald contain speculation that should be struck on the basis that statements that speculate as to the existence of facts that are outside the scope of the deponent's information or knowledge are impermissible in an affidavit: see *Rules of Civil Procedure*, R. 4.06(2) & 39.01(5); *Desjardins v. Mooney*, [2001] O.J. No. 697 (S.C.), at para. 4.

[119] The applicants submit that these statements fall into two categories:

> First are statements that are not tendered to prove the truth of what they aver, but rather the fact of the speculation itself. For example, in paragraph 122 of Ada's Affidavit, she states: I don't know if there is any correlation between my health problems and the pollution but I often wonder about that. My daughter Felicia and I are currently participating in a study with University of Michigan professor Nils Basu, testing my body for contamination. They took samples of my hair, blood, urine and nails. They also took samples of dust from my house, soil samples outside my house, and my samples of my drinking water, and my pet bird's feathers. They haven't given me the results yet and I am scared what they might find.
>
> The second category of statement to which the Respondents object are those that are tendered to prove the truth of the conclusions therein, which the Applicants submit are not speculation but permissible lay witness opinion evidence based on personal observation and experiential capacity. [Applicant's Factum on the Motion to Strike the Affidavit Evidence, at para. 68-69.]

2012 ONSC 2316 (CanLII)

[120] With respect to the first category, I agree with the applicants that some of the impugned passages, such as the one at para. 122 of Ms. Lockridge's affidavit, are not proffered for the truth of the contents of the premise but as evidence of uncertainty and fear. Another example is the Ronald Plain's statement that "my fear became a reality in 2010 when I learned that the Ministry allowed Suncor to increase its production again" (Ronald Plain's Affidavit, at para. 139). The point of this passage is the fear of increased pollution.

[121] Other passages, however, such as para. 96 of the Lockridge affidavit, do contain inadmissible speculation. Although the applicants have agreed to delete the last sentence of this paragraph, the entire paragraph speculates that certain studies may not have continued as a result of government funding decisions. Speculation as to the health impacts of industry in the area are also inadmissible, except to the extent that the references are made for the purpose of establishing fear or uncertainty that relates to the 2010 Decision (and/or the disparate impact argument).

[122] In my view, however, the respondents' objections on this category are overly broad. For example, the respondents object to Ms. Lockridge's statement that some people don't visit her because of the pollution as inadmissible speculation as to the reason people do not come to visit her. While this is true, it could be understood as simply reflecting her interpretation. In my view, such speculation on the part of a lay witness is likely to be harmless and, properly considered, may be relevant to the arguments related to desperate impact. This is the sort of objection that can be best assessed by the hearing panel, in light of the determinations made on relevance to particular issues at that point.

Argument

[123] It is inappropriate for a witness to provide evidence, whether opinion or otherwise, that constitutes argument in support of that party's position on the issues that are to be decided by the court: see *Coote v. Zellers*, [2008] O.J. No. 809 (Div. Ct.), at para. 22; *Ontario (Ministry of Natural Resources) v. Ontario Federation of Anglers and Hunters*, [2001] O.J. No. 750 (Div. Ct.), at paras. 21, 26. The respondents submit that there are many paragraphs (approximately 80) in the affidavits of the applicants and Wilson Plain that contain argument that should be struck.

[124] The applicants submit that a statement is only improperly argumentative when it contains "a mere statement" of the law, legal opinion, or both. Lay witness opinion evidence based on personal observation is not, in their view, argument. They also submit that some of the impugned paragraphs are intended to support arguments about the psychological state of the applicants, which may be relevant to the issue of disparate impact.

[125] The applicants have, however, agreed to amend many of the paragraphs to which the respondents agree on this ground in their affidavits and that of Wilson Plain. These deletions or alterations are clearly set out in the chart appended to their factum.

[126] Although the respondents have objected to many of the paragraphs they claim contains impermissible argument on other grounds as well, my review of these paragraphs indicates (as does the applicants' factum) that the amendments they propose have been made largely in

2012 ONSC 2316 (CanLII)

response to the impermissible argument submission. I would not strike any additional paragraphs on the sole basis that they constitute impermissible argument. Some of the paragraphs which the respondents identify, however, may constitute improper opinion evidence or impermissible hearsay and should be struck on those grounds, as discussed above.

[127] In coming to this conclusion on this point, I take into consideration the applicants' submissions that some of these paragraphs may be relevant to the psychological state of the applicants or the impact of existing pollution on their community. One example is para. 13 of Ronald Plain's affidavit, which states that "I am compelled to deal with this huge threat to the future of the community". While such a statement is clearly argument (that there is such a threat), it is more of a statement of belief and determination. Such statements are not, in my view, prejudicial to the respondents because a court is unlikely to rely on such a statement in determining issues (other than psychological state and disparate impact, to the extent that it considers them to be relevant). I also take into account the fact that the impugned statements are made in the lay affidavits. There is little or no danger, in my view, that a court will be influenced by such impermissible argument.

[128] In *Ontario Federation of Anglers and Hunters*, the impugned affidavit argument which the court struck was filed by as expert evidence. In *Coote*, the affidavit evidence was filed by the self-represented party and accordingly may be understood to have represented a real risk that the line between evidence and legal argument would be confused. This is not the case in the present case. Moreover, many of the impugned paragraphs are also challenged on other grounds such as relevance which may be raised again before the panel.

Conclusion on the Motion to Strike Affidavit Evidence

[129] In the foregoing discussion, I have concluded that some of the evidence tendered is inadmissible and should be struck, although the decisions on admissibility and weight with respect to much of it should be left to the panel for the reasons I have set out.

[130] While I have real doubts as to the admissibility of much of the evidence on many of the grounds raised, especially relevance, striking the affidavits to the extent the respondents request would disrupt the narratives set out in the affidavits, making it harder, not easier, for the panel to understand the evidence. This is particularly true with respect to the affidavits submitted by the applicants themselves, and Wilson Plain as members of the community allegedly affected. In addition, general context and narrative is permissible, and this line is difficult to draw in a preliminary motion.

[131] One must keep the dual principles emerging from *Sierra Club* and similar cases in mind. On the one hand, it is important to define the scope of the application properly to avoid the proliferation of issues, and to ensure the record filed reflects the issues properly before the court. On the other hand, it is not for a motion judge to usurp the role of the hearing panel in determining the merits of the application. Where there is doubt concerning the admissibility of some or all of a given affidavit, it is best to err on the side of caution and not strike the material from the record.

2012 ONSC 2316 (CanLII)

[132] Moreover, as I have outlined, it will be necessary to make some determinations on the merits in order to finally determine the relevance of much of this evidence. For example, the determination of whether the applicants can establish sufficient risk of harm caused by the 2010 Decision to trigger the *Charter* violations they allege will, in turn, affect the relevance of significant quantities of the evidence that the applicants argue is relevant to issues of disparate impact.

[133] The applicants ask for leave to amend their affidavits with respect to the portions struck. The applicants rely on Rule 25.11 of the *Rules of Civil Procedure*:

> The court may strike out or expunge all or part of a pleading or other document with or without leave to amend, on the ground that the pleading or other document,
>
> (a) may prejudice or delay the fair trial of the action;
>
> (b) is scandalous, frivolous or vexatious; or
>
> (c) is an abuse of the process of the court.

[134] The applicants submit that any delay or prejudice to the respondents will not be significant because they have yet to file their responding material to the application (as opposed to the considerable material they filed on these motions). The respondents strenuously object on the basis that such amendments, at this stage, will only serve to extend and further complicate an already unwieldy (and, they argue, misconceived) proceeding.

[135] I would grant leave to amend only to the extent that the applicants have set out such amendments in the chart attached to their responding factum to the Motion to Strike Affidavit Evidence. Some of these are amendments, and some are deletions. I see no need to grant leave to amend the affidavits beyond this.

[136] Permission to amend, or to file additional material at this stage, beyond those which the applicants had already agreed to, will only serve to protract and complicate an already protracted and complex proceeding.

III. PROTECTIVE COSTS ORDER

[137] The applicants move for a protective costs order insulating them, absent improper conduct during this litigation, from adverse costs if the application for judicial review is ultimately unsuccessful. They submit that the application,

> …is a public interest case that raises important questions regarding the application of the *Charter*, protection of human health from exposure to cumulative emissions of contaminants associated with serious health risks, and the manner in which the Government Respondents approve releases of contaminants to air under the [EPA].

2012 ONSC 2316 (CanLII)

[138] They argue that the nature of this case is one with significant implications for other Ontario communities located in industrial pollution "hot spots". They also submit that their claims are *prima facie* meritorious in nature and that these considerations, along with their limited financial means and the disparity in means between them and both respondents, justifies a protective costs order in their favour.

[139] The applicants also submit that the non-financial costs of pursuing this application compound the impacts they have already suffered from living in Chemical Valley, and in particular, maintain that the possibility of an adverse costs award contributes to their already high level of stress and anxiety caused by living in Chemical Valley. The applicants argue that the test for obtaining a costs immunity order should be less stringent than that applicable to an interim or advance costs order as it is less drastic.

[140] The respondents counter that no Ontario court has made a protective costs order, citing *Farlow v. Hospital for Sick Children*, 2009 CanLII 63602 (ON S.C.), and they argue that the circumstances in this case do not warrant such an exceptional award. In particular, they submit that this is not a case where, absent such an order, access to justice will be impaired, because Ecojustice is representing the applicants *pro bono*, and so the application may proceed whether such an order is granted or not.

[141] In addition, they submit that the applicants have not established that the case is one of sufficient *prima facie* merit to justify the relief sought. They also submit that because the application, properly scoped, concerns only the April 2010 Decision, it is unlikely that the case will have much useful precedential value in other cases. They also point to the fact that this application has been brought in the personal capacities of the applicants and not by the Aamjiwmaang First Nation, and there is no evidence that band members or the Band Council support the application.

[142] The respondents also argue that, unlike the case of *British Columbia v. (Minister of Water, Land and Air Protection) v. Okanagan Indian Band*, 2003 SCC 71, [2003] 3 S.C.R. 371, there are no special circumstances that justify such an exceptional award. They emphasize that a protective costs order as sought would mean that the applicants would have little incentive to ensure that the litigation proceeds in an efficient and just matter. While the order as sought would only apply "absent improper conduct", it is appropriate for courts to use costs to discourage unnecessary steps or conduct that unnecessarily complicates the litigation even if not rising to the level of being "improper": *Fellowes, McNeil v. Kansa General Insurance Co*, [2006] O.J. No. 5130 (S.C.). By way of example, the Government respondents submit that it is not appropriate to insulate the applicants from costs associated with the filing of large amounts of material which, they allege, is irrelevant to the determination of the application.

[143] The Government respondents state that while they are not prepared to undertake not to seek a costs award, they will not seek to collect on any cost award other than an award ordered for improper or clearly unnecessary steps in the proceeding of the sort that would attract a cost award under Rule 57.01(1)(e), (f) and (g).

2012 ONSC 2316 (CanLII)

[144] Suncor submits that it is a private litigant "who has been dragged into this litigation despite its best efforts to comply with the existing law…" and argues that it is unfair that it should effectively be punished with such an order.

The Law

General Principles

[145] In the usual case, costs are awarded to the prevailing party after judgment has been given. It has long been recognized that this general rule reflects a number of policy considerations, which include but are not restricted to the principle of indemnification of a successful party:

> The principle of indemnification, while paramount, is not the only consideration when the court is called on to make an order of costs; indeed, the principle has been called "outdated" since other functions may be served by a costs order, for example to encourage settlement, to prevent frivolous or vexations [*sic*] litigation and to discourage unnecessary steps. [Mark M. Orkin, *The Law of Costs*, 2nd ed., (Aurora, Ont.: Canada Law Book, 1987) (loose leaf), at p. 2-24.2.]

[146] It is clear that the court has jurisdiction to order costs that do not follow this general rule, and there are many illustrations of cases where such costs awards have been made and upheld, see, e.g., *B.(R.) v. Children's Aid Society of Metropolitan Toronto*, [1995] 1 S.C.R. 315. There, the applicants, who were Jehovah's Witnesses, had unsuccessfully argued that their *Charter* rights had been violated when a blood transfusion was administered to their baby daughter over their objections. The intervening Attorney-General was ordered to pay the applicants' costs despite succeeding in the application.

[147] As the Supreme Court of Canada has ruled in cases such as *Okanagan* and *Little Sisters Book and Art Emporium v. Canada (Commissioner of Customs and Revenue)*, 2007 SCC 2, [2007] 1 S.C.R. 38, one of the exceptional orders that may be available which derogate from the general costs rule is an advance or interim costs award. In *Little Sisters*, Bastarache and LeBel JJ. (at para. 40) noted that creative costs awards, such as adverse costs immunity, may be available in special circumstances.

[148] Although no Ontario court appears to have issued a protective costs order, there is a limited practice in England of doing so. In *R. (on the application of Corner House Research) v. Secretary of State for Trade and Industry*, [2005] 4 All E.R. 1 (D.A. (Civ. Div.)), the Court of Appeal indicated that such an order could be appropriate in exceptional circumstances where the court is satisfied that:

(a) The issues raised are of general public importance;

(b) The public interest requires that those issues should be resolved;

(c) The applicant has no private interest in the outcome of the case;

2012 ONSC 2316 (CanLII)

(d) Having regard to the financial resources of the applicant and the respondent(s) and to the amount of costs that are likely to be involved, it is fair and just to make the order; and

(e) If the order is not made, the applicant will probably discontinue the proceedings and will be acting reasonably in so doing.

[149] In *Corner House*, the applicant sought judicial review of a decision of the Secretary of State for Trade and Industry amending the procedures of the Export Credits Guarantee Department ("ECGD") of the Department of Trade and Industry, and the ECGD's standard forms relating to bribery, corruption and money laundering. The applicant was an educational, research and campaigning organization with a particular interest and involvement in the role of export credit agencies in the prevention of corruption and bribery in international business transactions. The grounds for the claim were, inter alia, that the defendant had failed to consult the claimant or other interested organizations before effecting far-reaching changes to the ECGD's anti-bribery and anti-corruption procedures, although it had consulted with its corporate customers and their representatives. Corner House claimed that the failure to consult was a serious breach of basic public law standards of fairness and the ECGD's own published consultation policy.

[150] In *Farlow*, Herman J., having reviewed Ontario case law on the point, noted that there is no specific provision in Ontario providing for Costs Protection Orders, and continued as follows at para. 89 of her reasons:

> However, a review of the more recent cases, in particular, and the references by the Supreme Court and the Ontario Court of Appeal to the availability of a costs immunity award, as well as a consideration of the court's broad costs discretion, leads me to conclude that the granting of costs immunity, while exceptional, may be considered in an appropriate case.

[151] In considering what an appropriate case might be in Ontario for such an award, Herman J. suggested that the criteria that the Supreme Court of Canada has established for advance or interim costs award may be useful. In *Okanagan*, the Court set out the following conditions at para. 40:

(a) The party seeking interim costs genuinely cannot afford to pay for the litigation and no other realistic option exists for bringing the issues to trial;

(b) The claim is *prima facie* meritorious; it would be contrary to the interests of justice for the opportunity to pursue the case to be forfeited just because the litigant lacks financial means; and

(c) The issues are of public importance and have not been resolved in previous cases.

[152] These conditions were further refined in *Little Sisters*, at paras. 39 to 44, as follows:

2012 ONSC 2316 (CanLII)

(a) The injustice that would arise if the application is not granted must relate to both the individual applicant and to the public. This does not mean, however, that every case of interest to the public will satisfy the test.

(b) An advance costs award must be an exceptional measure. The applicant must be able to demonstrate attempts to obtain private funding and, if not impecunious, must commit to making a contribution. The court should also consider different kinds of costs mechanisms.

(c) There would be no injustice if the issue could be settled or the public interest satisfied without an advance costs award.

(d) If an advance costs order is made, the litigant must relinquish some control over how the litigation proceeds.

[153] The criteria in the U.K., as well as Nova Scotia and Newfoundland, where protective costs award are provided for in the rules of court, suggest other factors to be taken into account as well:

(a) Whether the applicant's financial circumstances are such that the applicant would probably not proceed absent such an order;

(b) The extent to which the public has an interest in the issues being litigated; and

(c) The potential impact of such an award on the other parties. [*Farlow*, at para. 95-96.]

Analysis

[154] At the outset, I am satisfied that the considerations articulated by the Supreme Court of Canada in *Okanagan* and *Little Sisters*, as well as the additional factors set out by Herman J. in *Farlow*, are useful guidelines to be considered with respect to protective costs orders.

[155] The applicants submitted that the *Okanagan* and *Little Sisters* considerations should not be applied to a protective costs order because such an order is less onerous on the party subject to the order. *Corner House* and *Farlow* both recognize the similarity in principle between interim costs orders and protective costs orders, although the considerations as set out above are modified to some extent. The overarching point, repeatedly emphasized in all the case law, is the exceptional nature of such orders. While a protective costs order does not require the immediate outlay of cash, it does have the effect of undermining the usual incentive on the party obtaining such an order to consider the prospects of success in making decisions in relation to the litigation. The particular considerations or guidelines, in part, serve to reinforce this point.

[156] In my view, the three considerations articulated in *Farlow* do incorporate the appropriate guidelines or considerations articulated in *Okanagan* and *Little* Sisters. These considerations do not support the costs order sought by the applicant in this case for the following reasons.

2012 ONSC 2316 (CanLII)

[157] First, I am not satisfied on the evidence that the applicants' financial circumstances are such that they would probably not proceed if the costs order sought is not granted. Ecojustice is representing the applicants *pro bono*. While there is no doubt that the applicants are of modest means, this is not a case in which the applicants do not have access to justice in the sense that they cannot afford to continue the litigation without the order.

[158] The applicants argue, however, that they are unable to bear the risk of an adverse costs order in the event that they are unsuccessful, and submit further that the anxiety surrounding such a possibility compounds the psychological stress to which they are also subject. They also submit that the respondents are better able to absorb the costs associated with this litigation. From a financial perspective, that is no doubt true as a relative matter.

[159] However, the Government respondents indicate that while they would seek a costs award if successful, they would not "seek to collect on any cost award against the applicants in this application, except an award ordered for improper or clearly unnecessary steps in the proceeding…" (emphasis in original). While I do not doubt that the possibility of an adverse costs order vis-a-vis Suncor is stressful, this is not, in itself, sufficient to satisfy this consideration on these facts. Moreover, the argument that the stress the applicants suffer in this regard compounds the effects of living in Chemical Valley begs the question of whether or why Suncor should bear the costs, when no determination has been made in the merits of the argument whether there is or can be any link between the 2010 Decision involving Suncor's sulphur plant, and the harm or risk of harm about which the applicants complain.

[160] Second, the court must consider the extent to which the public has an interest in the litigation. This involves a consideration not only of whether there are public interests at stake in a general sense, but whether it is in the public interest that the litigation be pursued: see, for example, *Friends of the Greenpeace Alliance v. Ottawa (City)*, 2011 ONSC 472, 2011 CarswellOnt 315 (Div. Ct.). The question of whether the claim has *prima facie* merit is related to this, because it cannot be in the public interest to pursue clearly groundless litigation that is doomed to fail. The issues of public interest, public importance, and *prima facie* merit are thus relevant to the overall question of whether an injustice would result if the case could not be litigated.

[161] There can be no question that this case involves issues of public interest. Having said that, however, the fact that a claim asserts *Charter* rights or involves matters of some public interest does not necessarily satisfy this criteria: see *Farlow*. The matter must be of public importance.

[162] The issue in this judicial review application is very narrow. It concerns an administrative decision concerning sulphur production within an envelope of production that had previously been approved following public consultation. The level of sulphur production authorized by the April 2010 Decision had already been approved in 2004 following a process that had involved public consultation (with respect to which the applicants had, though notified, not participated). The consequences of success would be the quashing of the April 2010 Decision and would not affect general emissions from the refinery, and could not generally impose a cumulative effects

2012 ONSC 2316 (CanLII)

assessment into the regulatory process, though the applicants and Ecojustice advocate on behalf of such change.

[163] This is very different, for example, from the *Corner House* decision of the English Court of Appeal. There, the applicants sought judicial review of a decision which had imposed far-reaching changes to the ECGD's anti-bribery and anti-corruption procedures. The consequences of quashing such a decision as that carry very important public interest effects.

[164] Similarly, in *Okanagan*, the issue was whether the four respondent Bands had aboriginal title to the land and were entitled to log them, as they had begun to do. The Bands filed a notice of constitutional question challenging ss. 96 and 123 of the *Forest Practices Code of British Columbia Act*, R.S.B.C. 1996, c. 159, as conflicting with their constitutionally protected aboriginal rights after the after the Minister of Forests issued stop work orders and commenced proceedings to enforce the orders. The issues, and the direct results of the litigation, were of public interest and of great importance to the applicants. The issue there was a logging regime vis-à-vis the Bands.

[165] I would also note that it is not clear to me that this case is *prima facie* meritorious in the sense that the Supreme Court of Canada discussed this issue in *Little Sisters*, although it is not, in my view, a frivolous application. As discussed earlier in these reasons in relation to the applications to strike, the applicants must show a causal connection between the impugned Decision and the harms or risks of harm they allege that they have suffered. Without prejudging the hearing of the application on its merits, it is not immediately clear on a *prima facie* basis that the relevant evidence before the court on this issue can establish that.

[166] This point illustrates the reason for considering both public importance and merits as part of the considerations for exceptional costs orders such as the one sought here. The order sought here would undermine one of the fundamental policies which underlie the usual costs order, which is to create an incentive for litigants to consider the merit of the cases they bring.

[167] In this case, while the issues are of public interest in broad sense, the narrow nature of the impugned decisions and the limited remedy available in a judicial review application lead to the conclusion that the application does not have sufficient public importance to justify such an exceptional costs order. It cannot be said, in my view, that an injustice would result if this case could not be litigated.

[168] In addition, the fact that the applicants are not bringing this judicial review application in a representative capacity is relevant to the public interest consideration. There is no evidence as to the position of the Band or of the members of the community as a whole with respect to this particular application. While I would not consider this factor, in itself, to be fatal to this motion, it would in general be easier to meet the public interest and public importance components of the test if it were clear that the community which is, according to the application, so profoundly affected, supported it. This is in no way a reflection on the individual applicants, who have clearly worked tirelessly on the broader issues underlying this application with the entire community in mind.

2012 ONSC 2316 (CanLII)

[169] The third consideration mentioned in *Farlow* particular to protective costs orders is the potential impact on the other parties.

[170] While the Government respondents oppose the order sought, the impact upon it would arguably not be great because it has undertaken not to enforce a costs order, absent unreasonable conduct on the applicants' part as discussed above.

[171] Suncor, however, is in a different position. It is a private party, as was the hospital respondent in *Farlow*. Suncor submits that it,

> …has been dragged into this litigation despite its best efforts to comply with the existing law, and has been threatened with irreparable harm and the closure of its refinery. Suncor had conducted itself in a reasonable manner throughout. It is unfair that Suncor should be punished with a costs order. [Suncor, Protective Costs Order Factum, at (para. 4(f).]

[172] Suncor argues that the application is based upon extensive irrelevant and inadmissible evidence, and the erroneous assumption that the April 2010 orders permitted Suncor to increase production of fuel products (and related contaminant emissions) from the refinery.

[173] As discussed earlier, I have concerns about the admissibility of a considerable amount of the affidavit evidence filed, but have concluded that much of it should be left for the hearing panel to determine. In the meantime, Suncor (and the Government respondents) have not yet filed their responding material to the application. The issues in this application, and particularly the extent to which they may involve earlier approvals upon which Suncor has relied over the years, are very important to it. While Suncor has not filed evidence relating to its anticipated costs in this application, the indications, based on this application, are that they will be considerable.

[174] The consequences of the order sought would be to force Suncor, a private party, to bear a large part of the costs of this litigation, no matter what the outcome on the merits. This is not justified as a preliminary decision in the present circumstances. There is no allegation whatsoever of wrongdoing on its part, as the applicants themselves note. The applicant's real concern is with the fact that the regulatory framework does not require the consideration of cumulative effects. As Suncor notes, it has been required to defend this application although the relief is not sought directly from it.

[175] In these circumstances, there are other alternatives to the traditional costs award that could be considered at the end of the litigation. A court might not grant costs to the respondents, even if they are successful. It might grant costs to the respondent only with respect, for example, to costs increased by the filing of material it concluded to be irrelevant or otherwise improper. On the other hand, as *B.(R.)* demonstrates, it would be open to a court to order either or both respondents to pay the applicants' costs even if it was not successful. The point, however, is that this determination is most properly made following the resolution of the application so that the court may consider all relevant factors. I note that a number of the cases upon which the applicants rely in support of exceptional costs orders are cases in which such orders have been

2012 ONSC 2316 (CanLII)

made at the end of the litigation: see e.g. *Incredible Electronics Inc. v. Canada (Attorney General)* (2006), 80 O.R. (3d) 723 (S.C.).

[176] In sum, the fact that the applicants have *pro bono* representation, the public interest considerations as I have outlined them, as well as the potential effect of this award on Suncor, satisfy me that this is not a case that warrants such an exceptional award. The risk that the applicants will decide not to proceed does not justify undermining the usual costs incentive on litigants to carefully consider the merits of their claims and the particular manners in which they are made. I am unable to conclude that an injustice would result if this case could not be litigated. Moreover, such an award in these circumstances would not justify the impact that it would have on Suncor, irrespective of the ultimate results of the litigation. This is particularly so when the court, following the hearing of the application, will have ample discretion to fashion an award that is fair and appropriate, and which considers at that time, all the policies underlying costs awards.

[177] For these reasons, the application for a protective cost order is dismissed.

IV. CONCLUSION

As set out above, the motion to dismiss the application is dismissed. The application to strike evidence is allowed to the extent set out in these reasons above, and otherwise dismissed without prejudice to the respondent's right to contest the admissibility before the hearing panel. The motion for a protective costs order is dismissed.

V. COSTS

If the parties are unable to agree as to the costs at these motions, they may file written submissions with the court within 45 days on a timetable to be agreed upon by themselves, failing which they may seek further direction from the court.

_____

Harvison Young J.

Released:

2012 ONSC 2316 (CanLII)

CITATION: Lockridge v. Director, Ministry of the Environment, 2012 ONSC 2316
DIVISIONAL COURT FILE NO.: 528/10
DATE: 20120607

ONTARIO

SUPERIOR COURT OF JUSTICE

DIVISIONAL COURT

B E T W E E N:

ADA LOCKRIDGE and RONALD PLAIN

Applicants

– and –

DIRECTOR, MINISTRY OF THE ENVIRONMENT, HER MAJESTY THE QUEEN IN RIGHT OF ONTARIO, AS REPRESENTED BY THE MINISTER OF THE ENVIRONMENT, THE ATTORNEY GENERAL OF ONTARIO and SUNCOR ENERGY PRODUCTS INC.

Respondents

REASONS FOR DECISION

Harvison Young J.

Released: 20120607

2012 ONSC 2316 (CanLII)

TAB 2

Environmental Review Tribunal
Tribunal de l'environnement

Ontario

ISSUE DATE: December 23, 2014 **CASE NO.:** 14-048

Fairfield v. Director, Ministry of the Environment

In the matter of an appeal by Anne Fairfield filed July 3, 2014 for a Hearing before the Environmental Review Tribunal pursuant to section 142.1 of the *Environmental Protection Act*, R.S.O. 1990, c. E.19, as amended, with respect to Amended Renewable Energy Approval No. 1590-979LNP issued by the Director, Ministry of the Environment, on June 20, 2014 to Vineland Power Inc., under section 47.5 of the *Environmental Protection Act*, regarding a class 4 wind facility with a total expected generation capacity of 9 megawatts (MW), known as the HAF Wind Energy Project located at 9556 Sixteen Road Lot 20, Concession 6 in the Township of West Lincoln, Regional Municipality of Niagara, Ontario.

Heard : September 8, 9 and 10, 2014 in Smithville, Ontario.

APPEARANCES:

Parties	**Counsel/Representative[+]**
Anne Fairfield	Deborah Murphy[+]
Director, Ministry of the Environment	Andrew Weretelnyk
Vineland Power Inc.	Scott Stoll Jody Johnson Laura Dean (student-at-law)
Presenters	
Loretta Shields	Self-represented
Anne Meinen	Self-represented
Zlata Zoretic	Self-represented

DECISION DELIVERED BY JUSTIN DUNCAN AND HEATHER I. GIBBS

REASONS

Background

[1] On June 20, 2013, Vic Schroter, Director, Ministry of the Environment ("MOE" or the "Ministry") issued Renewable Energy Approval No. 1590-979LNP (the "Original REA") to Vineland Power Inc. (the "Approval Holder") under s. 47.5 of the *Environmental Protection Act*, R.S.O.1990, c. E.19 ("*EPA*"). The Original REA is for a renewable energy project known as the HAF Wind Energy Project, consisting of the construction, installation, operation, use and retiring of a Class 4 wind facility with five wind turbines, with a total nameplate capacity of nine megawatts, located at 9556 Sixteen Road Lot 20, Concession 6, in the Township of West Lincoln, in the Regional Municipality of Niagara, Ontario (the "Project").

[2] After the Project was constructed and the Approval Holder began operating it, on June 20, 2014, the MOE issued amendments to the Original REA for the Project (the "REA Amendments"). The amendments replace the definition of "Application" in the REA to incorporate documentation received from the Approval Holder up to June 16, 2014, including a Property Line Setback Assessment Report ("PLSA Report") that was not included in the application for the Original REA and, additionally, deletes two conditions in the Original REA relating to post-construction monitoring and reporting for woodland raptor nesting habitat.

[3] On July 3, 2014, Anne Fairfield (the "Appellant") filed a Notice of Appeal of the decision of the Director to issue the Amended REA with the Environmental Review Tribunal (the "Tribunal"). Ms. Fairfield appeals under s. 142.1(3) of the *EPA*, on the grounds that engaging in the Project in accordance with the Amended REA will cause serious harm to human health or will cause serious and irreversible harm to plant life, animal life or the natural environment.

[4] On August 5, 2014, the Appellant also filed a Notice of Constitutional Question ("NCQ") alleging that s. 47.5 and s. 142.1 of the *EPA* violate her rights to life, liberty and

security of the person under s. 7 of the *Canadian Charter of Rights and Freedoms* (the "*Charter*").

[5] A preliminary hearing took place on August 6, 2014. At that time, the Tribunal heard and determined requests for participant and presenter status, and dealt with certain scheduling matters. Additionally, the Tribunal heard a motion by the Approval Holder to dismiss the appeal.

[6] On August 8, 2014, the Tribunal gave an oral disposition of the motion via telephone conference call, granting the motion in part by striking certain portions of the Notice of Appeal. The Tribunal issued a written disposition on August 13, 2014. The Tribunal partially granted the motion on the basis that the Appellant had appealed the Original REA, which was settled. (The settlement can be found in the Tribunal decision *Engel v. Ontario (Ministry of the Environment)*, 2013 CarswellOnt 14872). The Tribunal's written reasons on the motion were delivered on September 19, 2014, striking several issues from the Notice of Appeal because they were either part of the settled appeal or otherwise unrelated to the REA Amendments. These matters included contaminated fill, buried electrical cables and gas well safety. An aspect of the constitutional challenge of s. 47.5 of the *EPA* was also struck as being outside the Tribunal's jurisdiction.

[7] As a result of the motion, what remains at issue in this appeal are the REA amendments made on June 20, 2014 to incorporate the PLSA Report into the definition of "Application", and the deletion of the monitoring conditions for woodland raptor nesting habitat in the Project's post-construction phase. A constitutional challenge relating to s. 142.1 of the *EPA* also remains at issue.

[8] Pursuant to s. 145.2.1 of the *EPA*, the onus is on the Appellant to establish that engaging in the Project in accordance with the REA Amendments will cause serious harm to human health (the "Health Test") and/or serious and irreversible harm to plant life, animal life or the natural environment (the "Environment Test").

[9] For the reasons that follow, the Tribunal finds that the Appellant has failed to meet either the Health Test or the Environment Test and has not established the necessary elements of a s. 7 *Charter* violation and, therefore, the appeal is dismissed.

Relevant Legislation

[10] The Amended REA was issued by the Director under the authority of s. 47.5 of the *EPA* which provides that the Director may alter the terms and conditions of a REA if he or she is of the opinion that it is in the public interest to do so, as follows:

> 47.5 (1) After considering an application for the issue or renewal of a renewable energy approval, the Director may, if in his or her opinion it is in the public interest to do so,
>
> (a) issue or renew a renewable energy approval; or
>
> (b) refuse to issue or renew a renewable energy approval.
>
> (2) In issuing or renewing a renewable energy approval, the Director may impose terms and conditions if in his or her opinion it is in the public interest to do so.
>
> (3) On application or on his or her own initiative, the Director may, if in his or her opinion it is in the public interest to do so,
>
> (a) alter the terms and conditions of a renewable energy approval after it is issued;
>
> (b) impose new terms and conditions on a renewable energy approval; or
>
> (c) suspend or revoke a renewable energy approval.
>
> (4) A renewable energy approval is subject to any terms and conditions prescribed by the regulations.

[11] The test applicable to appeals such as this one can be found in s. 145.2.1 of the *EPA* which provides that the Tribunal shall consider only whether engaging in the Project in accordance with the REA meets the Health Test or the Environment Test:

> 145.2.1 (2) The Tribunal shall review the decision of the Director and shall consider only whether engaging in the renewable energy project in accordance with the renewable energy approval will cause,
>
> (a) serious harm to human health; or

> (b) serious and irreversible harm to plant life, animal life or the natural environment.
>
> (3) The person who required the hearing has the onus of proving that engaging in the renewable energy project in accordance with the renewable energy approval will cause harm referred to in clause (2) (a) or (b).
>
> (4) If the Tribunal determines that engaging in the renewable energy project in accordance with the renewable energy approval will cause harm referred to in clause (2) (a) or (b), the Tribunal may,
>
> (a) revoke the decision of the Director;
>
> (b) by order direct the Director to take such action as the Tribunal considers the Director should take in accordance with this Act and the regulations; or
>
> (c) alter the decision of the Director, and, for that purpose, the Tribunal may substitute its opinion for that of the Director.
>
> (5) The Tribunal shall confirm the decision of the Director if the Tribunal determines that engaging in the renewable energy project in accordance with the renewable energy approval will not cause harm described in clause (2) (a) or (b).
>
> (6) The decision of the Director shall be deemed to be confirmed by the Tribunal if the Tribunal has not disposed of the hearing in respect of the decision within the period of time prescribed by the regulations.

[12] Also relevant to this appeal are provisions of *Ontario Regulation* ("*O. Reg.*") *359/09* of the *EPA*. Section 53(1)(b) of *O. Reg. 359/09* stipulates that turbines must be set back from property lines at a minimum distance that is equivalent to the height of the turbine excluding its blades, while s. 53(2) and s. 53(3) set out where this property line setback requirement does not apply, including where a proponent submits a written assessment demonstrating that adverse impacts will not result and setting out any preventative measures that are required to address the possibility of any adverse impacts:

> 53.(1) No person shall construct, install or expand a wind turbine that is to form part of a Class 3, 4 or 5 wind facility unless,
>
> (b) the distance between the centre of the base of the wind turbine and all boundaries of the parcel of land on which the wind turbine is constructed, installed or expanded is equivalent to, at a minimum, the height of the wind turbine, excluding the length of any blades.

(2) Clause (1) (b) does not apply in respect of a boundary of the parcel of land on which the wind turbine is constructed, installed or expanded if the abutting parcel of land on that boundary is,

(a) owned by the person who proposes to engage in the renewable energy project in respect of the wind turbine; or

(b) owned by a person who has entered into an agreement with the person mentioned in clause (a) to permit the wind turbine to be located closer than the distance specified in clause (1) (b).

(3) Clause (1) (b) does not apply if,

(a) the distance between the centre of the base of the wind turbine and all boundaries of the parcel of land on which it is constructed, installed or expanded is equivalent to, at a minimum, the length of any blades plus 10 metres; and

(b) as part of an application for the issue of a renewable energy approval or an environmental compliance approval in respect of the construction, installation or expansion of the wind turbine, the person who is constructing, installing or expanding the wind turbine submits a written assessment,

(i) demonstrating that the proposed location of the wind turbine will not result in adverse impacts on nearby business, infrastructure, properties or land use activities, and

(ii) describing any preventative measures that are required to be implemented to address the possibility of any adverse impacts mentioned in subclause (i).

[13] Finally, s. 1 and s. 7 of the *Charter* state:

1. The *Canadian Charter of Rights and Freedoms* guarantees the rights and freedoms set out in it subject only to such reasonable limits prescribed by law as can be demonstrably justified in a free and democratic society.

7. Everyone has the right to life, liberty and security of the person and the right not to be deprived thereof except in accordance with the principles of fundamental justice.

Issues

[14] The three issues on this appeal are:

Issue No. 1: Whether engaging in the Project in accordance with the REA Amendments will cause serious harm to human health.

Issue No. 2: Whether engaging in the Project in accordance with the REA Amendments will cause serious and irreversible harm to plant life, animal life or the natural environment.

Issue No. 3: Whether the Appellant's s. 7 *Charter* rights have been violated.

Issue No. 1: Whether Engaging in the Project in Accordance with the REA Amendments will Cause Serious Harm to Human Health

Discussion

[15] Section 145.2.1(3) of the *EPA* mandates that the person who required the hearing has the onus to prove that engaging in the Project in accordance with the approval will cause the harm under the Health Test. In order for the Appellant to satisfy her onus under the Health Test, on this appeal she must satisfy the Tribunal that the operation of the Project in accordance with the REA Amendments will cause serious harm to human health.

[16] The definition of "Application" in the Original REA was replaced in the REA Amendments to allow for the inclusion of a PLSA Report as follows:

> 11. "Application" means the application for a Renewable Energy Approval dated July 30, 2012 and signed by Thomas A. Rankin, President, Vineland Power Inc., and all supporting documentation submitted with the application, including amended documentation submitted up to June 20, 2013, and as further amended by the application for a Renewable Energy Approval amendment dated March 24, 2014 and signed by Thomas A. Rankin, and all supporting documentation submitted with the application including amended documentation submitted up to June 16, 2014.

[17] The PLSA Report was submitted to the Director in March 2014. The Appellant argues that the acceptance of this PLSA Report after the Original REA was approved has resulted in serious harm to human health in the nature of psychological impacts on her and other members of the public.

[18] The Director and the Approval Holder take the position that the Appellant has failed to lead any evidence necessary to meet the Health Test.

Evidence

[19] The Appellant and two presenters, Zlata Zoretic and Anne Meinen, testified in support of the Appellant's case on Issue No. 1. Additionally, Vic Schroter, the Director, testified under summons obtained by the Appellant. Jordan Beekhuis, a project engineer working with the Approval Holder, testified on behalf of the Approval Holder in relation to the process leading to the Amended REA. The Director did not call any witnesses specifically to testify in relation to health issues.

[20] The Approval Holder objected to paragraphs contained in the witness statements of Ms. Zoretic and Ms. Meinen as being outside of the scope of the appeal, and submitted that the Appellant's witness statement was incomplete and that she ought to not testify as a result. The Tribunal allowed the Appellant to testify to her concerns she raised in various documents leading up to the hearing that were relevant to the appeal. The Tribunal has considered the Approval Holder's submissions in determining the relevance and weight to be afforded to the evidence of Ms. Zoretic and Ms. Meinen, discussed below.

[21] During the first day of hearing, the Appellant made a request that the Tribunal conduct a site visit. This request was denied orally by the Tribunal at the hearing on the basis that site visits are used primarily to assist the Tribunal in understanding evidence and the issues presented at the hearing, as outlined in the Tribunal's Practice Direction for Site Visits. The Tribunal found it had sufficient explanation of the evidence before it in relation to property line setback distances (including maps and aerial photographs) and woodland raptor nesting habitat such that a site visit was unnecessary to appreciate or understand the evidence or issues before it.

[22] There was no disagreement with the setback distances measured by the Approval Holder's consultant and set out in the PLSA Report. That report indicated that all five of the turbines meet the minimum setback requirement of at least 550 metres ("m") from the nearest non-participating noise receptor, and that none of the turbines is located closer to a non-participating property line than the length of the turbine blades plus 10 m (i.e., 59 m in this case) as required by *O. Reg. 359/09*. The PLSA Report

does confirm that four of the five turbines are located closer to a non-participating property line than the height of the turbine tower (i.e., 95 m). The PLSA Report shows the following property line setback distances for each of the four wind turbines that are located less than 95 m from the closest property line:

Turbine Number	Property Line Setback Distance
1	66.62 m
2	89.90 m
3	73.59 m
5	88.70 m

[23] As noted above, *O. Reg. 359/09* requires that a proponent file a PLSA Report where a turbine tower is to be located less than 95 m from a property line. There was no disagreement in this case that the Approval Holder's application for the Original REA was deficient in that it failed to properly describe the setback distances above and failed to include a PLSA Report necessary to support a request for setbacks less than the 95 m.

[24] Brief summaries of the additional evidence of witnesses who provided testimony on Issue No. 1 are set out below.

Anne Fairfield

[25] Ms. Fairfield testified at the hearing on her own behalf. Ms. Fairfield is a Director of the West Lincoln and Glanbrook Wind Action Group Inc. which is in opposition to the Project. Ms. Fairfield's property is not one of the properties located less than 95 m from a Project turbine, but her property is within the area studied for the Project.

[26] Ms. Fairfield testified about the efforts she took to learn details about property line setbacks and specifically about the PLSA Report filed by the Approval Holder in support of its application for the Amended REA. She testified that she believed the Director was essentially allowing the Approval Holder to roll back the clock two years to file something that should have been filed with its application for the Original REA or,

alternatively, that the approval process was improperly iterative in nature, thereby allowing the Approval Holder to seek amendments to the Original REA at any time.

[27] Ms. Fairfield took issue with what she viewed as limited public consultation during the process leading to the approval of the Amended REA and the fact that the public's level of trust in the process was undermined, and that additional stress on her and other neighbours of the Project was the result.

[28] Ms. Fairfield expressed concern about what impact the Project may have on her health and testified that she has self-diagnosed as having "pre- and post-turbine stress disorder". It was not explained what she meant by this "disorder" but it appears this is how Ms. Fairfield refers to the stress associated with engaging in the approval process and, subsequently, with living close to the Project.

[29] Ms. Fairfield testified that she views the Approval Holder's failure to include the PLSA Report with its application for the Original REA as a "cover up" of a falsehood, and believes that rather than issuing the Amended REA, the Director ought to have revoked the Original REA entirely given what she views as a contravention of the regulations.

[30] Finally, Ms. Fairfield testified that she wonders what else remains to be fixed with the REA, which the public does not yet have knowledge of. She believes the Original REA is "illegal", that the Approval Holder should not be rewarded for covering up information by having an amended REA issued. In her view the Amended REA ought to be revoked and the Project components removed entirely.

[31] On cross-examination, Ms. Fairfield acknowledged that she has not visited a doctor in relation to stress and acknowledged that she has not filed any medical evidence documenting health issues already suffered or that may be suffered in future by herself or others in relation to the Project.

Zlata Zoretic

[32] Ms. Zoretic provided fact evidence as a presenter in support of the appeal. She is the property owner whose property line is 89.9 m from turbine #2 of the Project.

[33] Ms. Zoretic testified that she is one of the local residents living close to the turbines who is non-participating, in the sense that she does not have a participation contract with the Approval Holder.

[34] Ms. Zoretic explained the various negotiations she is aware of that led to the placement of the turbines on the properties where they are now located. She explained why she did not agree to having a turbine placed on her land, including her view that she would be unfairly impacting her neighbours' rights to enjoyment of their land.

[35] She testified that turbine noise interferes with her sleep and several of the turbines dominate views from her home. Ms. Zoretic believes her rights to her land have been interfered with.

[36] Additionally, Ms. Zoretic testified that she has concerns about property line setbacks and the potential for harmful effects on wildlife, livestock, property values and her health.

[37] Ms. Zoretic also expressed the desire to ensure that applicants for REAs are made to file complete and accurate applications for REAs before construction begins. She expressed her belief that without such a requirement, interests in land could be taken or private land impacted absent due process, outcomes she likened to her experience in communist Yugoslavia 40 years ago when individual rights were ignored and portions of her father's farm were taken without his input. She stated that she "trusted" the Approval Holder to follow the regulations, and that her trust was betrayed.

[38] Finally, Ms. Zoretic testified that she believes turbine #2 is too close to her home and she wants it moved or taken down entirely.

[39] On cross-examination, Ms. Zoretic acknowledged that she did not have any evidence that linked any specific health issue to the property line setbacks from turbines.

Anne Meinen

[40] Anne Meinen also provided fact evidence as a presenter in support of the appeal. Ms. Meinen is a local property owner with an “L”-shaped property that is located approximately 79.4 m and 73.6 m from turbine #3 at two points on the property line.

[41] Ms. Meinen testified that she has been farming various parcels of land in the area for over 40 years. Although she does not live on the property at issue, as she rents out the residence on the property and has an employee that assists her with farming it, Ms. Meinen stated that turbine #3 impacts her ability to grow field crops for a number of reasons set out below.

[42] The bulk of Ms. Meinen’s testimony related to her worries about what the Project could mean for the health of those using the land and her financial interests in the property. For example, she states that, since turbines do not meet the 95 m setback requirement, her safety is not ensured.

[43] Additionally, Ms. Meinen testified that she might need additional liability insurance due to the proximity of the turbine, that any aerial seeding she may want to do in future might be interfered with, that future technological advances in farming practices may be interfered with by the proximity of a wind turbine, that her property values have likely been depressed, that her tenant’s pets are disturbed by the noise from the turbines at night, and that if her tenants or the custom worker at her farm ever decide to leave as a result of the presence of the turbines then she will be harmed financially.

[44] Finally, Ms. Meinen testified that she also worried about what else was absent from the Approval Holder’s application for the Original REA that was missed by the Director.

[45] On cross-examination, Ms. Meinen acknowledged that she has been able to grow crops on her land, despite the presence of the Project. It was clarified that Ms. Meinen is concerned that turbine #3 will interfere with future farming technologies, rather than any present-day farming practices she currently engages in. Ms. Meinen also acknowledged that none of her remaining concerns had yet come to pass, nor did she have any evidence that the impacts she fears have actually occurred. Ms. Meinen reiterated that she continues to worry about these potential issues however.

Vic Schroter

[46] The Director of the MOE, Vic Schroter, was summonsed to testify by the Appellant. Mr. Schroter approved the Original REA and reviewed the application in support of the Amended REA, though another Director signed the Amended REA due to Mr. Schroter being absent at the time. Mr. Schroter testified that at the time the Original REA was signed, he believed, based on the application supplied by the Approval Holder, that the Project met the setback requirement of 95 m from non-participating property owners' property lines.

[47] Mr. Schroter explained why the changes were made in the Amended REA. Mr. Schroter testified that after individuals contacted the MOE indicating that setback distances appeared less than 95 m, the Ministry's Niagara District Office in St. Catharines became responsible for considering any enforcement issues. His office became responsible to consider the application for amendment, once it was filed. Mr. Schroter also confirmed that the public had not been broadly consulted through the Environmental Bill of Rights Registry on the Amended REA before it had been issued. Mr. Schroter testified that the MOE trusts the information given to it by a proponent in an REA application.

Jordan Beekhuis

[48] Jordan Beekhuis is a project engineer employed by Rankin Construction Inc., one of the shareholders in Vineland Power Inc., the Approval Holder. He appeared as a fact witness for the Approval Holder to explain the approval process for the Amended REA. Mr. Beekhuis worked on the Project beginning in late 2011, overseeing

operations and coordinating with the manufacturer of the turbines and with various construction subcontractors.

[49] Mr. Beekhuis testified that part of his due diligence review for the Project involved confirming that the turbine locations could meet regulatory requirements for the application for the original REA. He testified that, in looking for "red flags" and determining whether a location is suitable for a project, he would check for a turbine /property line setback of blade length plus 10 m, which is viable assuming a proper report is completed that demonstrates compliance with regulatory requirements. He also testified that in the application for the Original REA the PLSA Report was a requirement because not all turbines could meet the turbine-height property line setback, but the Approval Holder's consultant had mistakenly not included the PLSA Report with the original application.

[50] Mr. Beekhuis testified that he had become aware of this issue only after local residents complained about setbacks shortly after turbines had been erected. He testified that the PLSA Report had been omitted mistakenly, and that setback distances from property lines were not marked on the maps submitted to the MOE in the original application. Thereafter, after becoming aware of the problem, he testified that he worked with the Approval Holder and the Ministry to bring the Project and the Original REA into compliance with regulatory requirements by submitting a PLSA Report and other documentation.

[51] Mr. Beekhuis testified that after the property line setback issue had been discovered in November 2013, the Approval Holder consulted with property owners on adjacent properties as required under *O. Reg. 359/09* s. 53(2)(b). The landowner adjacent to turbine #5 entered into an agreement with the Approval Holder while Ms. Meinen (adjacent to turbine #3 at two locations), Ms. Zoretic (adjacent to turbine #2) and the property owner adjacent to turbine #1 declined to enter into agreements. Mr. Beekhuis also testified that these property owners were given the opportunity to comment on the PLSA Report.

[52] Mr. Beekhuis also testified that the MOE had engaged in public consultation after receiving the application for the Amended REA from the Approval Holder and had provided a summary of those comments for responses by the Approval Holder.

[53] Finally, Mr. Beekhuis testified that the PLSA Report identified the potential for adverse impacts to abutting land. His witness statement states they are “limited to crop and vegetation damage or soil compaction only in the unlikely event of turbine collapse”, and states that preventative measures were identified to address these possibilities in the PLSA Report.

Analysis and Findings

[54] In order to satisfy the Health Test, the Appellant must show that the Project, operating in accordance with the Amended REA, will cause serious harm to human health. In *Erickson v. Ontario (Ministry of the Environment)* (2011), 61 C.E.L.R. (3d) 1 (“*Erickson*”), at paras. 596-648, the Tribunal engaged in a legal analysis of three areas in considering the Health Test: (a) "will cause", (b) "serious harm", and (c) "to human health".

[55] The component “will cause” can be satisfied where it is shown that the operation of a project results in either direct or indirect harm (*Erickson* at para. 631). “Serious harm” has been found to require an assessment of the specific harm complained of on a case-by-case basis and to consider all the evidence to determine whether the harm is serious in nature given that there can be differing interpretations of what is serious (*Erickson* at para. 638). “Human health” has been found to contemplate not only the absence of symptoms but a state of complete physical, mental and social well-being and as a result, it is to be assessed on a case-by-case basis (*Erickson* at paras. 166 and 645).

[56] In this instance, although the Appellant has raised what could be viewed as a legitimate human health issue – stress or anxiety – for the reasons that follow the Tribunal is not convinced on a balance of probabilities that the stress or anxiety complained of by Ms. Fairfield is caused by the operation of the Project in accordance

with the REA Amendments, or that it could be considered serious harm to human health.

[57] The bulk of the evidence adduced in support of the Appellant's case on Issue No. 1 was focused on the process leading to the approval of the Amended REA and on the identification of potential areas of Project impacts.

[58] The Tribunal has no doubt that the witnesses testifying in support of the Appellant's appeal are genuinely concerned about the potential for future harm resulting from the Project. However, the Tribunal is not satisfied that the Appellant has met the evidentiary burden of proving serious harm to the health to any individual or group of individuals. The only human health evidence in this case was in the form of self-diagnosis by non-experts, and allegations of stress caused by the possibility of future harm.

[59] In relation to speculation about future harm, witnesses testified about their concerns as to what else might be wrong with the Amended REA that the Director has yet to fix. This does not constitute proof that serious harm to human health will be caused by the operation of the Project, as required by s. 145.2.1 of the *EPA*.

[60] The Appellant must prove on a balance of probabilities that harm will occur, rather than that it may occur. Evidence that only raises the potential for harm does not meet the evidentiary onus. Speculation about future events and outcomes is not sufficient (*Erickson* at paras. 851 and 871).

[61] In relation to stress, the Appellant led no medical evidence at the hearing other than the testimony that she believes she suffers from "pre- and post-turbine syndrome", along with evidence from presenters that the process and the possibility of future impacts cause them stress and worry. The majority of the evidence led appeared to relate to the frustration individuals have experienced with the process of approval undertaken by the Director, and the fact that a regulatory requirement was overlooked such that amendments were even needed. Importantly, the Tribunal heard no specific

evidence linking the operation of the Project in accordance with the specific amendments at issue on this appeal, to any particular human health issue.

[62] The witnesses for the Appellant also testified that stress arose as a result of the fact that the Director's decision to amend the Original REA was made absent broad public consultation. The Appellant and the presenters testified about their distrust of the MOE and the Approval Holder as a result of the issuance of an REA that subsequently needed to be amended. They expressed a loss of trust in the government's oversight of wind projects and their impacts, and resulting feelings of betrayal.

[63] In her submissions on the Health Test, the Appellant focused on the omission from the Original REA of measured property line setback distances and a property line setback assessment. The health submissions were closely linked to those with respect to the *Charter* claim. The Appellant submits that "while there is no 'expert medical evidence' in support of this submission, the (evidence of Ms. Meinen and Ms. Zoretic) must be considered as compelling, truthful evidence."

[64] Specifically, the Appellant submits with respect to Ms. Zoretic that:

> the actions of the proponent have caused Ms. Zoretic… to now feel that the "rules" in this country are becoming the same as the "rules" of the Communist country she fled. It is submitted that this alone is a travesty of justice and an absolute infringement on her guaranteed rights to the security of her psychological integrity and the protection against actions of the government which threaten that integrity.

[65] The Appellant submits with respect to Ms. Meinen that

> For the first time, she must worry about issues which had never presented themselves prior to this Project. And while this individual understood that, in general principal, she would have to accept this project, she did not understand that it would be acceptable for the owners of the Project to deliberately contravene the very regulations which permitted that the Project to move forward. She now worries about what else has been done illegally and how much of a negative impact this particular situation will have on her livelihood in the future, and as such, is now living under a level of stress she had not previously experienced. It is submitted that this, as well, is a travesty of justice and absolute infringement on her rights to the security of her psychological integrity and the protection against actions of the government which threaten that integrity.

[66] The Appellant further submits that a determination by the Tribunal "that the proponents actions are acceptable … will only serve to add to the already high levels of stress being experienced by citizens living in the Project area."

[67] Even if the Tribunal were to accept that stress levels experienced during the approval processes would continue during the operation of the Project, and even if the Appellant had shown that the stress could be attributed to the amendments at issue on this appeal, the evidence of stress and anxiety evinced during the hearing does not, in the Tribunal's view, rise to the level of "serious harm" as required by the Health Test.

[68] With regards to the Appellant's characterization of the errors made in the Original REA as being deliberate, no evidence was adduced showing that the failure to include the PLSA Report with the application for the Original REA was intentional or that it was originally omitted with any intent to mislead or hide anything from the public.

[69] Even if it had been demonstrated to the Tribunal that the process by which the Original and Amended REAs were approved was inadequate or that the omission of the PLSA Report was deliberate, without more, one cannot simply assume that serious harm to human health will result. Under the *EPA*, the Tribunal has only the narrow jurisdiction to consider whether operating in accordance with the Project will cause serious harm to human health or serious and irreversible harm to plant life, animal life or the environment. As noted below, the MOE's exercise of prosecutorial discretion is an entirely different matter.

[70] In relation to speculation about future harm, witnesses testified about their concerns as to "what else might be wrong" with the Amended REA that the Director has yet to fix. Such speculation does not constitute proof that serious harm to human health will be caused by the operation of the Project in accordance with the REA Amendments. As stated in *Erickson* the legal test under this section of the *EPA* requires evidence that the Project will cause serious harm to human health, not that it might cause or may cause such harm.

[71] Finally, the Appellant made reference during the hearing and in submissions to a lack of enforcement of the *EPA* by the Ministry in this instance, and a lack of verification of information provided in applications for REAs by the MOE. The Appellant argues in her written submissions, for example, that "(r)evoking the original REA will send a clear message that no one is above the law and regulatory conditions are not voluntary standards to be met upon discovery of non-compliance."

[72] The Tribunal does not view it as relevant to the determination of issues on this appeal whether or not the Ministry has decided to charge the Approval Holder under the *EPA* for errors made in its application for the Original REA. The Ministry's enforcement decision is a separate matter altogether that does not assist the Tribunal in determining whether serious harm to human health will result from the operation of the Project in accordance with the REA Amendments.

[73] Similarly, whether or not the MOE has decided to undertake a process to independently verify the contents of the Approval Holder's application for the Original REA and the Amended REA does not, in itself, assist the Tribunal in determining whether or not the operation of the Project in accordance with the REA Amendments will result in serious harm to human health or the environment.

[74] The Appellant additionally made submissions that the Original REA should be considered invalid, and asked that the Tribunal revoke the Original REA. The Tribunal notes that it issued an order in this appeal on September 19, 2014, following a motion by the Approval Holder to dismiss or strike portions of the appeal. In that order, the Tribunal struck a number of issues raised by the Appellant relating to the Original REA which had been subject to a prior settlement agreement, or were not the subject of the Director's decision to approve the REA Amendments. The question before the Tribunal in this appeal is whether engaging in the Project in accordance with the REA Amendments will cause harm. The validity of the Original REA is not the legal question to be determined by the Tribunal in this proceeding.

[75] The Tribunal finds that the Appellant has failed to demonstrate that the operation of the Project in accordance with the REA Amendments will cause serious harm to human health.

Issue No. 2: Whether Engaging in the Project in Accordance with the REA Amendments will cause Serious and Irreversible Harm to Plant Life, Animal Life or the Natural Environment

Discussion

[76] In order for the Appellant to meet the onus established under the *EPA*'s Environment Test, she must satisfy the Tribunal that the operation of the Project in accordance with the REA Amendments will result in serious and irreversible harm to plant life, animal life or the natural environment.

[77] As previously noted, the Amended REA removed two conditions relating to woodland raptors nesting habitat in the post-construction phase of the Project.

[78] Condition I4 was contained under the heading "Thresholds and Mitigation" in the Original REA and required that monitoring of woodland raptor nesting habitat at two woodland locations be undertaken as follows:

> I4. The Company shall implement the post-construction monitoring described in the Environmental Effects Monitoring Plan and the Environmental Impact Study, described in Condition I1, including the following:
>
> (1) Disturbance Monitoring for Raptor Nesting Habitat (Mill Creek-Inverary Woods, Twenty Mile Creek Woodland)

[79] Condition I14 had been contained under the heading "Reporting and Review of Results" in the Original REA. It established the reporting requirements for the monitoring undertaken under Condition I4 as follows:

> I14. The Company shall report, in writing, both the winter raptor mortality levels and the yearly (May-March) raptor mortality levels for the post-construction monitoring described in Conditions I4(1), to the Ministry of Natural Resources for three (3) years on an annual basis

and within three (3) months of the conclusion of the March mortality monitoring for each year, with the exception of the following:

(1) if either of the bird mortality thresholds described in Conditions I6(4) or I6(5) is reached or exceeded , the Company shall report the mortality event to the Ministry of Natural Resources within 48 hours of observation;

(2) for any and all mortality of species at risk (including a species listed on the Species at Risk in Ontario list as Extirpated, Endangered or Threatened under the provincial *Endangered Species Act, 2007*) that occurs, the Company shall report the mortality to the Ministry of Natural Resources within 24 hours of observation or the next business day;

(3) if the raptor mortality threshold described in Conditions I6(3) is reached or exceeded for turbines located within 120m of bird significant wildlife habitat, the Company shall report mortality levels to the Ministry of Natural Resources for the additional three (3) years of effectiveness monitoring described in Condition I9, on an annual basis and within (3) months of the conclusion of the March mortality monitoring for each year;

(4) if the raptor mortality threshold described in Conditions I6(3) is reached or exceeded for turbines located outside 120 m of bird significant wildlife habitat, the Company shall report mortality levels to the Ministry of Natural Resources for the additional two (2) years of cause and effects monitoring described in Condition I10, on an annual basis and within three (3) months of the conclusion of the March mortality monitoring for each year; and

(5) if the Company implements operational mitigation following cause and effects monitoring in accordance with Condition I10 due to raptor mortality thresholds being reached or exceeded, the Company shall report mortality levels to the Ministry of Natural Resources for the three (3) years of subsequent effectiveness monitoring described in Condition I10, on an annual basis and within three (3) months of the conclusion of the March mortality monitoring for each year.

[80] The Appellant submits that the deletion of these monitoring and reporting conditions for woodland raptor nesting habitat will result in serious and irreversible harm to raptors.

[81] The Director submits that the Appellant has not demonstrated that the deletion of these monitoring and reporting conditions for woodland raptor nesting habitat will result in serious harm to raptors. Additionally, the Director submits that even if the Appellant has proven that serious and harm will result, it has not been proven that such harm is irreversible.

[82] The Approval Holder's submissions mirror those of the Director. The Approval Holder submits that the Appellant has filed no evidence showing how operating the Project in accordance with the REA Amendments will impact raptors and as a result, the Appellant has failed to meet the onus under the Environment Test.

Evidence

[83] The Appellant and one presenter, Loretta Shields, testified in support of the Appellant's case on Issue No. 2. Emma Valliant, an employee of the Ministry of Natural Resources ("MNR"), testified as a fact witness for the Director. Erin McLachlan testified as an expert on behalf of the Approval Holder. All witnesses focused their testimony on the deletion of Conditions I4 and I14.

Loretta Shields

[84] Loretta Shields, a presenter testifying in support of the Appellant's appeal, is a local resident who is a long standing member of several nature groups in the Niagara Region, including the Niagara Peninsula Field Naturalists and Niagara Woodlot Association.

[85] Ms. Shields provided fact evidence focusing on the issue of identification and monitoring of woodland raptor nesting habitat. More specifically, Ms. Shields testified by way of a power point presentation that was attached to her witness statement that set out her views about the Natural Heritage Assessment Report ("NHA Report") and associated materials filed with the application for the Original REA. Ms. Shields' view was that there were deficiencies in all three components of the natural heritage assessment, namely the records review, site investigation and evaluation of the significance of woodland raptor nesting habitat in the Project area. Her testimony was that:

a. Multiple raptor species are located in the region in which the Project is located;

b. The Approval Holder failed to contact local residents, the Niagara Peninsula Hawkwatch organization or the Christmas Bird Count compilers that may have had additional information about woodland raptor nesting habitat;

c. There is no evidence that the *Ontario Bird Breeding Atlas* was consulted in conducting the records review;

d. There is no evidence that field investigations were conducted at the proper time of year or in the proper manner to find raptor nests;

e. Overwintering habitat was not properly considered and assessed;

f. An area of approximately 18 hectares ("ha") of woodland located between turbines #2 and #3 was not properly identified as a candidate woodland raptor nesting habitat area; and

g. Species abundance levels in the Project area have not been properly assessed.

[86] Ms. Shields testified that she did not have confidence in the Approval Holder's data gathering and assessment for woodland raptor nesting habitat and that, therefore, it was difficult to decide what mitigation measures were actually required to ensure local raptor populations were not irreversibly harmed by the Project. She concluded with her view that until proper field studies are conducted, the Project puts local raptor populations in peril.

[87] In cross-examination, Ms. Shields acknowledged that she is not an expert and has not received any specific training in the categorization of woodlands, though Ms. Shields did mention that it is common knowledge that the region is an important area for raptors, citing the proximity of the Project to an important raptor habitat area such as Beamer Falls.

[88] Additionally, Ms. Shields conceded that none of the woodland areas in the study area were greater than 30 ha in size, the threshold for considering a woodland area as a "candidate significant woodland raptor nesting habitat area" under the MNR's *Significant Wildlife Habitat Ecoregion Draft Criteria Schedule* for Ecoregion 7E.

Ecoregion 7E represents much of southwestern Ontario, including the study area for the Project.

[89] Ms. Shields also conceded that remaining conditions in the Amended REA required monitoring of bird strikes but she stressed that her concern was not just one of mortality from strikes but also related to habitat disturbance issues.

[90] Finally, Ms. Shields agreed that she had no evidence to provide in relation to raptor population levels in the area or mortality rates that could be expected from the operation of the Project. Ms. Shields testified that a Red-tailed hawk and an American kestrel had been found dead in the area but Ms. Shields acknowledged that she was not sure how these raptors had been killed.

Erin McLachlan

[91] Ms. McLachlan is a terrestrial ecologist who was called by the Approval Holder to testify. Ms. McLachlan was qualified by the Tribunal as an expert to give opinion evidence in relation to terrestrial ecology, wildlife habitat assessment and the assessment of terrestrial ecosystems in the context of renewable energy approvals and natural heritage assessments.

[92] Ms. McLachlan was the lead author of the NHA Report, Environmental Impact Study Report and Environmental Effects Monitoring Plan for Birds and Bats that were collectively prepared for the Approval Holder as part of its application filed for the Original REA.

[93] Ms. McLachlan testified that the NHA Report was prepared to document the records review, site investigations and evaluation of significance of all natural features within 120 m of the Project location.

[94] Ms. McLachlan explained the process followed to evaluate the significance of woodland raptor nesting habitat using the MNR's *Natural Heritage Assessment Guide for Renewable Energy Projects, 2011* as required by *O. Reg. 359/09*.

[95] It was Ms. McLachlan's evidence that all woodlots within 120 m of the Project location were properly delineated in the NHA Report. It was her evidence that all natural areas, including woodland raptor nesting habitat, were classified using the MNR's Ecological Land Classification for Southern Ontario system and assessed as per the requirements of *O. Reg. 359/09*.

[96] Ms. McLachlan testified that there were two areas of candidate significant woodland raptor nesting habitat identified and these two areas were treated as significant without having to evaluate for significance, consistent with MNR's 2011 *Natural Heritage Assessment Guide for Renewable Energy Projects*.

[97] Ms. McLachlan critiqued the evidence provided by the Appellant's witness Ms. Shields. Ms. McLachlan testified that Ms. Shields had misinterpreted the MNR's *Natural Heritage Assessment Guide* and the steps taken by Ms. McLachlan's team in carrying out their assessment, including consulting proper documentation and characterization of candidate significant woodland raptor nesting habitat areas. For example, Ms. McLachlan confirmed that her team had consulted the *Ontario Bird Breeding Atlas* and local bird specialists in the Niagara Region in their records review. Additionally, she responded to Ms. Shields' critique of the site investigations by stressing that field investigations are normally used to determine types of species and abundance as part of an evaluation of significance which was unnecessary in this instance as both candidate woodlots had been treated as significant.

[98] Ms. McLachlan expressed the opinion that Conditions I4 and I14 had been included in the Original REA in error and that remaining conditions contained in the Amended REA address the need for mitigation and reporting of impacts on raptors in the post-construction phase.

[99] Finally, in answering questions by the Tribunal, Ms. McLachlan expressed her opinion that the construction of the Project would not have any impact on woodland raptor nesting habitat given that construction would not impact any wooded areas.

Additionally, Ms. McLachlan expressed the opinion that operation of the Project would not have any impacts on woodland raptor nesting habitat and that bird strikes would be the only potential for impacts to raptors during operation.

Emma Valliant

[100] Ms. Valliant was called by the Director as a fact witness, meaning she was not qualified to give opinion evidence to the Tribunal. Ms. Valliant has been employed by the MNR since 2003 and has been a renewable energy planning ecologist since April 2014. Ms. Valliant was not involved in the review of the NHA Report for the Project before the Original REA was approved in 2013.

[101] In May 2014, after the Director received the application for the Amended REA, Ms. Valliant was assigned to consider whether post construction monitoring of woodland raptor nesting habitat was required for the Project.

[102] It was Ms. Valliant's testimony that, as there is no significant woodland raptor nesting habitat within 120 m of the Project, there was no requirement for post construction monitoring and reporting for impacts on such habitat in the Original REA and that the inclusion of conditions I4 and I14 in the Original REA was an error. As a result, on behalf of MNR, she had communicated to MOE staff in May 2014 that these conditions could be removed as an administrative change and advised that they had been erroneously included in the Original REA.

[103] Ms. Valliant explained the rationale for the advice she had provided to the Director on behalf of MNR before the Amended REA was issued, which was as follows:

a. No known records for woodland raptor nesting habitat were identified by the Approval Holder;

b. Two candidate woodland raptor nesting habitat sites were identified by the Approval Holder within 120 m of the Project but since these two sites are less than 30 ha in size (4.97 ha and 2.49 ha respectively), an evaluation of significance was not required;

c. The Approval Holder took the additional step to undertake a site investigation and had not identified any stick nests in the woodlots that would indicate that those areas had been used as nesting habitat by raptors;

d. The MNR issued a letter in April 2012 confirming that the natural heritage assessment had been prepared as required; and

e. As no significant woodland raptor nesting habitat was found within 120 m of the Project, in accordance with the MNR's *Natural Heritage Assessment Guide for Renewable Energy Projects*, no post construction monitoring and reporting was required.

[104] Ms. Valliant also explained how several of the monitoring and reporting conditions remaining in the Amended REA relating to raptors operate:

a. Condition I1 states that the Approval Holder shall implement the Environmental Effects Monitoring Plan dated March 2012 including bird mortality monitoring at all five turbine locations for three years of operations;

b. Condition I6 sets a mortality threshold of 2 raptors for the Project per year which, if reached or exceeded, requires the Approval Holder to implement various mitigation measures to reduce raptor-turbine strikes; and

c. Condition I15 requires reports summarizing the results of the mortality monitoring be submitted to the MOE and the MNR.

Analysis and Findings

[105] The Appellant has the onus of proof on this appeal under the Environment Test to show that the deletion of conditions I4 and I14 relating to woodland raptor nesting habitat in the post-construction phase of the Project will cause serious and irreversible harm to raptors.

[106] The evidence must show that the operation of the Project will cause serious and irreversible harm. As stated by the Tribunal in *Lewis v. Ontario (Ministry of the*

Environment), [2013] O.E.R.T.D. No. 70 ("*Lewis*") at para.54, it is insufficient to show that harm may result or could result. The Environment Test imposes a high evidentiary burden on appellants.

[107] On this appeal, there was significant debate during the hearing relating to whether the NHA Report was properly prepared in relation to woodland raptor nesting habitat. However, even assuming the report contained errors or omissions, the Tribunal did not hear any evidence showing that any such deficiencies will result in serious and irreversible harm to raptors.

[108] Even if it had been shown that deficiencies existed in both the application for the REA and the approval process carried out by MOE specifically in relation to woodland raptor nesting habitat, it does not necessarily follow that any such deficiencies will result in serious and irreversible harm to raptors as a result of the REA Amendments. The Appellant did not adduce evidence linking alleged process deficiencies to the serious and irreversible harm this Tribunal is specifically required to consider under the *EPA*.

[109] As stated by the Tribunal in *Lewis*, the test undertaken by the Tribunal in a s. 145.2.1 analysis is not the same as the analysis conducted by the MNR during the REA approval process. Paragraph 32 of *Lewis* sums up the findings of the panel in that case, which the Tribunal endorses on this appeal:

> To conclude on this aspect, the Tribunal finds that the work done at the REA approval stage (including any MNR sign-off regarding natural heritage features) and in other regimes (such as the *ESA* and Bald Eagle Guidelines) may be relevant information to consider under the *EPA* test, but it is not determinative because the statutory test is part of a distinct appellate process, which involves a different test than what is used by other decision-makers in reviewing applications for renewable energy approvals and other regimes.

[110] Under s. 24(2) of *O. Reg. 359/09* the Approval Holder was required to comply with MNR's *Natural Heritage Assessment Guide for Renewable Energy Projects* (the "NHA Guide") when applying for the Original REA. The NHA Guide directs applicants for REAs to consider the Significant Wildlife Habitat Eco-Region Criteria Schedules applicable to the area where a project is proposed. The Project in this case is located in

Ecoregion 7E. MNR's 2011 Draft Significant Wildlife Habitat Ecoregion 7E Criterion Schedule ("Ecoregion 7E Criteria") stipulates that the habitat criteria for considering an area as candidate significant wildlife habitat is that the area is "All natural or conifer plantation woodland/forest stands combined [greater than] 30 ha". The Ecoregion 7E Criteria remain in draft form. The 2011 draft of the Ecoregion 7E Criteria indicates that 10 ha of the 30 ha must be interior habitat, while the most recent 2012 draft has reduced that area to 4 ha of the 30 ha. Interior habitat is characterized in the Ecoregion 7E Criteria as that portion of woodland habitat that has a 200 m buffer of woodland surrounding it. There is no dispute on this appeal that there are no woodland areas within 120 m of the Project that are greater than 30 ha in total area and that have an interior habitat area of 10 ha or 4 ha.

[111] The dispute in this case relates to the level of assessment, information and detail that needed to be contained in the NHA Report filed with the application for the Original REA. The Appellant's submissions state as follows:

> 86. The discrepancies indicated at Para 85 above clearly indicate that complete, thorough study of the raptors natural nesting habitat in the Project area was not carried out nor was a thorough assessment of the findings of that study conducted. While the minimum woodland area of 30 hectares defines the habitat criteria in the SWH ecoregion 7E criterion schedule, site investigations still should have been conducted. As such, both the proponent and the MOECC failed in their legislated duties to thoroughly investigate the potential for harm, and determine, if applicable, appropriate mitigation.
>
> 87. It is submitted that, as a result of these failures, it is impossible to support the contention that it was proven post-construction monitoring of the raptors was unnecessary.

[112] The Tribunal is unable to conclude, based on the criticism leveled by Ms. Shields against the NHA Report, that removal of the post-construction woodland raptor habitat monitoring will cause serious and irreversible harm. For example, Ms. Shields disagreed with the MNR's reviewers respecting which local groups the Approval Holder ought to have contacted for relevant information. No evidence was provided indicating that, if different groups had been contacted, the Approval Holder would have obtained information indicating that the operation of the Project would cause serious and irreversible harm to raptor species.

[113] Some of the criticism Ms. Shields leveled against the NHA Report resulted from the fact that the report was not particularly detailed, leaving her to state that there was no evidence that certain steps had been taken.

[114] The Tribunal finds that Ms. McLachlan adequately addressed the issues raised by Ms. Shields in her testimony in criticism of the NHA Report. Most importantly, Ms. McLachlan explained that the woodlands identified, despite their size, were nevertheless treated as significant and mitigation considered to address any potential impacts as reflected in the remaining conditions in the Amended REA. The Tribunal accepts her expert opinion, which was uncontested, that the construction of the Project would not have any impact on woodland raptor nesting habitat given that construction would not impact any wooded areas.

[115] Even if it had been shown that errors or omissions remain in the NHA Report, the Tribunal cannot make the assumption, without evidence, that serious and irreversible harm will result from the operation of the Project as a result. MNR's NHA Guide appears to be directed at ensuring that potential impacts of a renewable energy approval are minimized in relation to aspects of the natural environment. It does not of necessity follow that a failure to meet those requirements will result in serious and irreversible harm. On the other hand, it may be that compliance with the NHA Guide does not ensure that serious and irreversible harm is avoided in every situation.

[116] No evidence was led showing that any impacts to raptors from the operation of the Project in accordance with the REA Amendments will result, other than direct strikes with the turbines. No evidence was led indicating that turbine strikes will cause serious and irreversible harm to raptors.

[117] The Tribunal notes that the monitoring, mitigation and reporting conditions relating to raptor turbine strikes remain in conditions I6, I9, I10, I11, I12 and I15 of the Amended REA. These conditions were in the Original REA and are not part of the current appeal.

[118] The Tribunal finds that the Appellant has failed to demonstrate that the operation of the Project in accordance with the REA Amendments will cause serious and irreversible harm to plant life, animal life or the natural environment.

Issue No. 3: Whether the Appellant's s. 7 *Charter* Rights have been Violated

Discussion

[119] Section 7 of the *Charter* provides that "Everyone has the right to life, liberty and security of the person and the right not to be deprived thereof except in accordance with the principles of fundamental justice."

[120] In *Chaoulli v. Quebec (Attorney General)*, [2005] 1 S.C.R. 791 the Supreme Court of Canada set out the following three stages for consideration of a s. 7 *Charter* claim:

a. Whether there has been a deprivation of life, liberty or security of the person;
b. If so, whether the deprivation is not in accordance with the principles of fundamental justice; and
c. If so, whether the breach is saved under s. 1 of the *Charter* as demonstrably justified in a free and democratic society.

[121] The burden is on the Appellant to satisfy the Tribunal that the first two stages of this analysis have been met. If the Appellant were successful in that regard, the burden would then shift to the respondents to prove that any breach is saved under the third stage of the analysis.

[122] The Appellant alleges that the approval of the Amended REA and/or s. 142.1 of the *EPA* violate security of the person under s. 7 of the *Charter*.

[123] In submissions, the Appellant repeats and relies upon the evidence summarized above under Issue No.1 relating to the process of approving the Amended REA and the

evidence of stress and anxiety expressed by various witnesses as the evidence in support of her *Charter* claim. In reply submissions, the Appellant reiterates that her s. 7 claim focuses on the psychological impact of the "contravention of regulations" by the Approval Holder and the "approval of the MOE of this contravention".

[124] The Director responds that the Appellant has failed to establish a breach of s. 7 of the *Charter* and further, that the Appellant has failed to prove that any harm was caused by s. 142.1 of the *EPA*.

[125] The Approval Holder also responds by submitting that the Appellant has not properly explained how a breach of s. 7 of the *Charter* arises in this context and has not filed sufficient evidence to reveal a breach of s. 7.

[126] The Director and the Approval Holder also raise the issue of whether the Appellant has public interest standing to bring a *Charter* claim on behalf of other individuals. Given the Tribunal's finding of a lack of evidence of any *Charter* breach, it is not necessary to address this additional argument.

Analysis and Findings

Evidence of a Section 7 Deprivation

[127] In previous REA appeals, the Tribunal has reviewed the leading jurisprudence under s. 7 of the *Charter* and has found that, for s. 7 to be engaged, the evidence led by an appellant must show that state action has caused harm of a serious nature (See: *Bovaird v. Ontario (Ministry of the Environment)* (2013) 83 C.E.L.R. (3d) 13 at paras. 501-503; *Dixon v. Ontario (Ministry of the Environment)*, [2014] O.E.R.T.D. No. 5 at paras. 71-73 and 81-84; *Drennan v. Ontario (Ministry of the Environment)*, [2014] O.E.R.T.D. No. 10 at para. 76; *Kroeplin v. Ontario (Ministry of the Environment)*, [2014] O.E.R.T.D. No. 24 at paras. 253-256). The Tribunal panel in the *Dixon* case made the following findings, which the Tribunal endorses in this case:

> 81. In reviewing the case law on s. 7 *Charter* claims, it is apparent that the courts have all held that the onus is on the claimant to establish, on

> the evidence provided, serious physical or psychological harm. Speculation, allegations and mere concerns do not suffice.
>
> 82. This proposition is stated in virtually every s. 7 *Charter* case. In *Chaoulli*, at paras. 111-117, the Supreme Court of Canada outlined the evidentiary base established in that case in some detail and then reviewed the evidentiary base in *R. v. Morgentaler*, [1988] 1 S.C.R. 30. The Court stated at para. 123 that the "...evidence here demonstrates that the prohibition on health insurance results in physical and psychological suffering that meets the threshold requirement of seriousness." In fact, courts have routinely outlined the evidentiary base they base their decisions upon in a s. 7 *Charter* claim. Also see: *Susan Doe v. Canada (Attorney General)*, [2006] O.J. No. 191, aff'd 2007 ONCA 11, at paras. 154-156; *PHS Community Services Society v. Canada (Attorney General)*, [2011] 3 S.C.R. 134 at para. 93; and *Bedford* at paras. 100-101.
>
> 83. The Court in *Chaoulli* went on to state:
>
> > 124. We conclude, *based on the evidence*, that prohibiting health insurance that would permit ordinary Canadians to access health care, in circumstances where the government is failing to deliver health care in a reasonable manner, therefore increasing the risk of complications and death, interferes with the life and security of the person as protected by s. 7 of the *Charter*. [emphasis added]
>
> 84. For a s. 7 *Charter* claim, the Tribunal finds that the onus is on the Appellants to establish, on the evidence, the claimants have suffered or will suffer serious physical or psychological harm.

[128] The evidentiary burden is on the Appellant under s. 7 therefore to prove that the REA Amendments or s. 142.1 of the *EPA* cause harm of a serious nature.

[129] In this case, the Appellant argues that the stress caused by the Project, and more particularly by the Director's approval of an amendment to the Project approval after discovering it did not originally comply with the regulatory requirement that a PLSA Report be filed, has and will cause serious harm to her health and that of others in the community.

[130] The Supreme Court of Canada has stated that, in order for s. 7 of the *Charter* to be engaged, the impugned law or state action must have a "serious and profound effect" on a person's psychological integrity (*New Brunswick (Minister of Health and Community Services) v. G.(J.)*, [1999] 3 S.C.R. 46 para. 60). With regard to stress and anxiety, the Approval Holder cited the following excerpt from *R. v. Morgentaler*, [1998] 1

S.C.R. 30 at para. 196, which the Tribunal agrees is an apt description of the position of the Appellant in this case:

> As to an asserted right to be free from any state interference with bodily integrity and serious state-imposed psychological stress, I would say that to be accepted, as a constitutional right, it would have to be based on something more than the mere imposition, by the State, of such stress and anxiety. It must, surely, be evident that many forms of government action deemed to be reasonable, and even necessary in our society, will cause stress and anxiety to many, while at the same time being acceptable exercises of government power in pursuit of socially desirable goals…. Governmental action for the due governance and administration of society can rarely please everyone. It is hard to imagine a governmental policy or initiative which will not create significant stress or anxiety for some and, frequently, for many members of the community.

[131] Based on the Tribunal's analysis of and findings on the evidence set out above, under Issue No. 1, the Tribunal is not satisfied that the Appellant has met the evidentiary burden of proving state-imposed psychological stress that has a serious and profound impact on the Appellant or other members of the community. As noted above, the only human health-related evidence in this case was in the form of self-diagnoses by non-experts, and allegations of stress caused by the possibility of future harm.

[132] The Tribunal finds that the totality of the evidence taken at its very highest does not meet the threshold of proving serious harm to any individual or group of individuals. In light of this finding on the evidence, it is unnecessary to consider the Director's argument whether the Appellant has proven that the harm complained of is caused by s. 142.1 of the *EPA* or by the REA Amendments themselves.

Principles of Fundamental Justice

[133] Even if the Appellant were able to satisfy the Tribunal that s. 7 is engaged, step 2 of the s. 7 *Charter* analysis mandates that the Appellant show that the deprivation of life, liberty or security of the person is not in accordance with the principles of fundamental justice. Given the Tribunal's finding that there is a lack of evidence for a finding that s. 7 is even engaged, the Tribunal does not view it as necessary to consider the principles of fundamental justice. However, the Tribunal sets out the following analysis and findings

on the principles of fundamental justice in the interests of providing a full analysis of the Appellant's *Charter* claim.

[134] Principles of fundamental justice are concerned with capturing inherently bad laws or state action that take away life, liberty, or security of the person in a way that runs afoul of our basic values: *Canada (Attorney General) v. Bedford*, [2013] 3 S.C.R. 1101 at para. 96. The principles of fundamental justice that have evolved since the *Charter* came into force include requirements that a law not be vague, arbitrary or overbroad in application. New principles may emerge as new contexts arise.

[135] In this instance, the Appellant has not referred to a principle of fundamental justice as established by jurisprudence, nor proposed a new principle, that may be applicable in the context of this appeal.

[136] The Tribunal did not hear evidence or submissions by the Appellant that would establish that either the specific process followed by the Director in this instance or s. 142.1 of the *EPA* generally run contrary to a principle of fundamental justice. More simply, on balance the evidence on this appeal did not reveal that s. 142.1 is a bad law or that the process engaged in by the Director ran contrary to a principle of fundamental justice.

Justification of Infringement

[137] Given the analysis above, it is unnecessary for the Tribunal to consider the third step in a *Charter* analysis, namely whether a violation of s. 7 can be demonstrably justified in a free and democratic society under s. 1.

[138] The Tribunal finds that the Appellant has failed to establish her claim under s. 7 of the *Charter*.

Conclusion

[139] The Appellant was understandably frustrated, after her extensive effort to engage in public consultation processes and a previous appeal of the Original REA, to find that

property line setback information was not included in the Original REA as it should have been, and conditions relating to raptor habitat were deleted with no public consultation. However, based on the above analysis, the Tribunal has found that the Appellant has not established that operating the Project in accordance with REA Amendments will cause serious harm to human health or serious and irreversible harm to plant life, animal life or the natural environment under s. 145.2.1 (4) of the *EPA*.

[140] Additionally, the Tribunal finds that the Appellant has not established, on the facts of this case, that the REA Amendments or s. 142.1 of the *EPA* violate the right to security of the person under s. 7 of the *Charter*.

Request for an Injunction by the Appellant

[141] In her written submissions, the Appellant requests that, should the Tribunal determine that "the Amendment to the REA or portions therefore shall stand", that an injunction be ordered until further studies are completed and the Approval Holder undertakes further actions relating to the property line setback issue.

[142] However, the Tribunal only has the power to order the remedies listed in s. 145.2(4) of the *EPA* where it has first determined that the Health Test or the Environment Test have been made out. Sections 145.2(4) and (5) of the *EPA* provide:

> 145.2(4) If the Tribunal determines that engaging in the renewable energy project in accordance with the renewable energy approval will cause harm referred to in clause (2) (a) or (b), the Tribunal may,
>
> (a) revoke the decision of the Director;
>
> (b) by order direct the Director to take such action as the Tribunal considers the Director should take in accordance with this Act and the regulations; or
>
> (c) alter the decision of the Director, and, for that purpose, the Tribunal may substitute its opinion for that of the Director.
>
> (5) The Tribunal shall confirm the decision of the Director if the Tribunal determines that engaging in the renewable energy project in accordance with the renewable energy approval will not cause harm described in clause (2) (a) or (b).

[143] As the Tribunal has found that the Appellant did not demonstrate that the Project will cause serious harm to human health, or serious and irreversible harm to plant life,

animal life or the natural environment, the Tribunal cannot order “alternative” remedies as requested by the Appellant.

Request for Costs by the Approval Holder

[144] In its final written submissions, the Approval Holder submitted that “this case warrants consideration for an order for the Appellant to pay Vineland’s costs of this appeal”, because the Appellant:

a. provided no medical or expert evidence to support the appeal;
b. filed a motion for stay which was not pursued; pursued issues beyond the Tribunal’s jurisdiction even after a motion to strike;
c. made bald, unsubstantiated assertions and allegations, without any actual evidence, about the intention, motivation and conduct of Vineland, without putting the proposition to Vineland’s representative in cross-examination.

[145] The Approval Holder requested an opportunity to make full cost submissions following the Tribunal’s decision on this appeal, should the appeal be dismissed.

[146] Rule 216 provides that a party may file a costs application with the Tribunal at any time prior to the conclusion of the Hearing, or no later than within 30 days from the date of the issuance of the reasons for the decision. In this case, however, the Tribunal finds that it has sufficient facts and information before it at the current time to determine that this is not an appropriate case in which to order costs.

[147] Rule 213 notes that the Tribunal has differing jurisdiction to award costs, depending on the type of appeal. In an appeal such as this one under s. 145.2.1 of the *EPA*, the Tribunal only has a limited authority, springing from s. 17.1(2) of the *Statutory Powers Procedure Act*, R.S.O. 1990, c. S.22, to award costs in situations of improper conduct in a proceeding.

[148] The Appellant was within her rights under the *EPA* to appeal the Amended REA. In its order of August 13, 2014 (reasons issued September 19, 2014), the Tribunal dismissed the Approval Holder's argument that the appeal should be dismissed on the grounds of no genuine issue for adjudication. While the Tribunal has ultimately determined that the Appellant brought insufficient evidence to satisfy the test under s. 145.2.1 of the *EPA*, the Appellant's conduct was professional throughout the proceedings, respectful of the Tribunal's process and orders, and there was nothing to suggest a costs order might be warranted. The Tribunal is mindful of the additional costs involved to all parties in preparing and responding to motions, and finds that the Approval Holder's chance for success in a costs motion in this case is so remote that it does not justify the costs involved to all parties to prepare and defend such a motion. The Tribunal therefore will not accept further submissions from the Approval Holder on costs in this case.

DECISION

[149] The appeal from the Amended REA is dismissed without costs.

Appeal Dismissed without Costs

JUSTIN DUNCAN
MEMBER

HEATHER I. GIBBS
VICE-CHAIR

TAB 3

Marchand, a minor by his litigation guardian Marchand v. The Public General Hospital Society of Chatham et al.*

[Indexed as: Marchand (Litigation guardian of) v. Public General Hospital Society of Chatham]

51 O.R. (3d) 97
[2000] O.J. No. 4428
Docket No. C25915

Court of Appeal for Ontario
Laskin, Goudge and Sharpe JJ.A.
November 27, 2000

* Application for leave to appeal to the Supreme Court of Canada was dismissed September 27, 2001 (Gonthier, Major and Binnie JJ.). S.C.C. File No. 28379. S.C.C. Bulletin, 2001, p. 1685.

Courts -- Judges -- Bias -- Reasonable apprehension of bias -- Conduct of trial -- Plaintiffs appealing dismissal of action -- Plaintiffs arguing that trial judge's failure to restrain unprofessional and uncivil conduct by defence counsel establishing unfair trial and reasonable apprehension of bias -- Informed and reasonable observer looking realistically at trial would not have apprehended bias or unfair adjudication.

Evidence -- Use of discovery evidence at trial -- Correcting answers given on examination for discovery -- Difference between formal and informal admissions.

Evidence -- Experts -- Expert's reports -- Evidentiary rulings at trial -- Experts may not testify about new matters not touched on in expert's report delivered before trial -- Rules of Civil Procedure, R.R.O. 1990, Reg. 194, rules 31.09, 53.03(1).

2000 CanLII 16946 (ON CA)

Evidence -- Experts -- Expert's reports -- Hearsay evidence -- Foundational facts -- Proof of foundational facts for expert's opinion normally going to weight and not admissibility of evidence -- Trial judge, however, not erring in ruling that expert's opinion lacking probative value where party's undertaking to prove foundational facts not satisfied.

The plaintiff JM was delivered by a Caesarean section performed on his mother, the plaintiff BM, by the defendant Dr. A at the defendant The Public General Hospital Society of Chatham ("the Hospital"). JM was born profoundly disabled. He and his parents sued Dr. A, the Hospital and three nurses for negligence. After a 165-day trial marked by rancour and hostility between counsel for the parties, the plaintiffs' action was dismissed. The plaintiffs appealed on the grounds that: (1) Granger J., the trial judge, erred in failing to find that the defendants were negligent in not properly monitoring BM and for not delivering JM earlier; (2) they did not receive a fair trial because of the trial judge's erroneous and one-sided evidentiary rulings; and (3) in failing to restrain the conduct of defence counsel, the trial judge's conduct of the trial raised a reasonable apprehension of bias.

Held, the appeal should be dismissed without costs, but the trial judgment should be varied to take account of the defendants' undertaking not to pursue the cost of the trial.

There was ample evidence to support the finding that the injuries were not caused by any act or omission of the defendants but were caused by a sudden rupture of the placenta resulting in cataclysmic oxygen deprivation. The evidentiary rulings did not support the plaintiffs' contention that they were denied the opportunity to fairly present their case, nor did these rulings create a reasonable apprehension of bias. The rulings reflected a sincere and diligent effort to conduct a fair trial. Virtually all the rulings were correct. The few errors were inconsequential and, even viewed cumulatively, did not result in any significant prejudice. Reviewing each impugned evidentiary ruling individually, this appeal failed because: (1) The trial judge did not err in ruling that Dr.

2000 CanLII 16946 (ON CA)

Fields, an expert witness called by the plaintiffs, could not be questioned about bradycardia (abnormally slow heart rate) because testimony about this topic was contrary to rule 53.03(1) of the Rules of Civil Procedure, which requires a party to serve an expert's report setting out the "substance" of the expert's proposed testimony. The "substance" requirement must be determined in light of the purpose of the rule, which is to facilitate trial preparation by providing opposing parties with adequate notice of opinion evidence to be adduced at trial. An expert may not testify about matters that open up a new field not touched upon by the report. In any event, even if the trial judge erred in his interpretation of rule 53.03, there was no prejudice because the evidence about bradycardia went to causation and Dr. Fields was not qualified to give expert evidence about causation. (2) In light of his ruling about the substance of Dr. Fields' report, the trial judge did not act improperly in refusing the plaintiffs' request for an adjournment, and this denial did not cause any injustice. (3) The trial judge did not err in denying leave to permit Dr. Silver, an expert witness who had been called by the plaintiffs, to testify about matters in a second report that described a new theory of causation. Had this testimony been admitted, the defendants' right to a full and fair defence would have been impaired because they would have been denied the right to cross-examine Dr. Manning, an expert already called by the plaintiffs. Re-calling Dr. Manning would have resulted in undue delay. (4) The trial judge did not err in ruling that the evidence of Ms. Kelly, a home care expert, and of Ms. Staub, an expert about future care costs, lacked probative value, when with respect to the foundational facts underlying their respective opinions, these witnesses intended to rely on videos filed at trial rather than the medical reports referred to in their written reports. In having these witnesses proceed in this way, the plaintiffs were in breach of an undertaking and were refusing to provide the factual foundation of the opinions. Although normally proof of foundational facts goes to the weight and not the admissibility of the opinion, it was open to the trial judge to conclude that the observations and conclusions could not be established in any way other than by adducing the medical reports containing those observations and conclusions. (5) The trial

2000 CanLII 16946 (ON CA)

judge did not err in allowing Dr. A to correct his discovery evidence that JM showed oligohydramnios at birth. Dr. A's discovery answer was not a formal admission, which cannot be withdrawn except by leave of the court or the consent of the party in whose favour it was made, and it was always open to explain his answer in testimony. Although under rule 31.09, a party shall forthwith advise that the answer to a question was incorrect, the impact of corrections is a matter to be decided by the trial judge and the combined effect of rules 31.09 and 53.08 is that a trial judge must grant leave to introduce the evidence unless to do so would cause prejudice that could not be overcome by an adjournment or costs. (6) The trial judge did not err in restricting the cross-examinations of certain defendants to preclude opinio evidence about the conduct of other defendants. The impugned questioning went beyond the witnesses' involvement in the events of the case. (7) Although the trial judge did err in his ruling about the plaintiffs' cross-examination of the defendant Colebrook by ruling that the plaintiffs were precluded from contradicting her on her discovery evidence that they had themselves had read into the record, no prejudice flowed from that ruling. (8) There was no basis to interfere with the trial judge's ruling prohibiting the use of demonstrative evidence, which is a matter of discretion. (9) In view of the pleadings, there was an adversity of interest between the co-defendants, and the trial judge correctly ruled that Dr. A had a right to cross-examine a witness called by the co-defendants. (10) There was no merit in the submissions that the trial judge erred or was inconsistent in his rulings favouring the defendants with respect to the evidence of Drs. Tithecott, Smith and Eyman.

The trial judge's conduct of the trial did not raise a reasonable apprehension of judicial bias. The most serious of six categories of alleged judicial misconduct was that the trial judge refused to restrain defence counsel's repeated attacks on plaintiffs' counsel's integrity and competence, which attacks included repeated accusations of manipulating evidence; of deliberately misinforming witnesses and feeding them answers; of deliberately flouting, subverting and ignoring the rules of practice; and of showing contempt for the trial judge and his rulings. The record supported the plaintiffs'

2000 CanLII 16946 (ON CA)

contentions and showed that the degree of trust between counsel had vanished, replaced by a level of rancour and hostility, rarely, if ever, seen in an Ontario courtroom. Although the conduct was not all one-sided, defence counsel was mostly responsible for conduct that by any reasonable standards of civility was unacceptable for any counsel, let alone senior counsel. That the conduct was unacceptable was candidly ackn owledged. The issue for the appeal, however, was what impact this conduct had on the fairness of the trial. The question was whether an informed person viewing the matter realistically would conclude that the way the trial judge dealt with defence counsel attacks on plaintiffs' counsel created a reasonable apprehension of bias and thus deprived the plaintiffs of a fair trial. The answer to this question was negative. First, the trial judge did not remain silent. Second, the failure of the trial judge to do more to restrain defence counsel does not automatically indicate judicial bias. Nothing in the record or in the trial judge's reasons suggested that he condoned the conduct or lent the weight of his office to the defence position. An informed and reasonable observer looking realistically at the trial unfolding would not apprehend bias or unfair adjudication. Third, and admittedly less importantly, most of the attacks occurred during motions and not during the presentation of evidence.

Turning to the other categories of alleged judicial misconduct, while several examples of defence counsel's treatment of the plaintiff BM showed counsel in an unflattering light, none of the examples suggested judicial bias. In making interventions, the trial judge did not act improperly so as to prevent the plaintiffs from fairly presenting their case. There was no merit in the suggestion of misconduct because the trial judge spoke to defence counsel in the absence of plaintiffs' counsel about scheduling. There was nothing in the trial judge's remarks to substantiate the allegation that he unfairly criticized plaintiffs' counsel and there was nothing inappropriate in his reasons for judgment that showed antipathy to the plaintiff BM. Finally, the totality of the plaintiffs' complaints did not establish a reasonable apprehension of bias.

2000 CanLII 16946 (ON CA)

Cases referred to

Auto Workers' Village (St. Catherines) Ltd. v. Blaney, McMurtry, Stapells, Friedman (1997), 14 C.P.C. (4th) 152 (Ont. Gen. Div.); Bachalo v. Robson (1995), 101 Man. R. (2d) 316, 35 C.P.C. (3d) 230 (Q.B.); Burke v. Gauthier (1987), 24 C.P.C. (2d) 281 (Ont. H.C.J.); Capital Distributing Co. v. Blakey (1997), 33 O.R. (3d) 58, 147 D.L.R. (4th) 372, 10 C.P.C. (4th) 109 (Gen. Div.); Christoyiannis (Litigation guardian of) v. Benoit, [1998] O.J. No. 5200 (Gen. Div.); Collins v. Belgian Dry Cleaners, Dyers and Furriers Ltd., [1952] 1 D.L.R. 712, 4 W.W.R. (N.S.) 241 (Sask. C.A.); Committee for Justice and Liberty v. Canada (National Energy Board), [1978] 1 S.C.R. 369, 68 D.L.R. (3d) 716, 9 N.R. 115; Draper v. Jacklyn, [1970] S.C.R. 92, 9 D.L.R. (3d) 264; Graat v. R., [1982] 2 S.C.R. 819, 144 D.L.R. (3d) 267, 45 N.R. 451, 2 C.C.C. (3d) 365, 31 C.R. (3d) 289, 18 M.V.R. 287 (sub nom. R. v. Gratt); Iler v. Beaudet [1971] 3 O.R. 644 (Co. Ct.); Machado v. Pratt & Whitney Canada Inc. (1993), 17 C.P.C. (3d) 340 (Ont. Master); Majcenic v. Natale, [1968] 1 O.R. 189, 66 D.L.R. (2d) 50 (C.A.); McEachrane v. Children's Aid Society of Essex (County) (1986), 10 C.P.C. (2d) 265 (Ont. H.C.J.); Ollet v. Bristol Aerojet Ltd., [1979] 3 All E.R. 544 (Q.B.); Quantrill v. Alcan-Colony Contracting Co. (1978), 18 O.R. (2d) 333 (C.A.); R. v. Abbey, [1982] 2 S.C.R. 24, 39 B.C.L.R. 201, 138 D.L.R. (3d) 202, 43 N.R. 30, [1983] 1 W.W.R. 251, 68 C.C.C. (2d) 394, 29 C.R. (3d) 193; R. v. Grosse (1996), 29 O.R. (3d) 785, 107 C.C.C. (3d) 97, 19 M.V.R. (3d) 197 (C.A.) [Leave to appeal to S.C.C. refused (1997), 209 N.R. 400n]; R. v. Lavallee, [1990] 1 S.C.R. 852, 67 Man. R. (2d) 1, 108 N.R. 321, [1990] 4 W.W.R. 1, 55 C.C.C. (3d) 97, 76 C.R. (3d) 329; R. v. S. (R.D.), [1997] 3 S.C.R. 484, 161 N.S.R. (2d) 241, 151 D.L.R. (4th) 193, 218 N.R. 1, 477 A.P.R. 241, 118 C.C.C. (3d) 353, 10 C.R. (5th) 1; R. v. Scardino (1991), 46 O.A.C. 209, 6 C.R. (4th) 146 (C.A.); Shipman v. Antoniadis (1975), 8 O.R. (2d) 449, 58 D.L.R. (3d) 321 (C.A.); Thorogood v. Bowden (1978), 21 O.R. (2d) 385, 89 D.L.R. (3d) 604 (C.A.); Wade v. Sisters of Saint Joseph of the Diocese of London (1976), 2 C.P.C. 37 (Ont. H.C.J.)

Statutes referred to

Evidence Act, R.S.O. 1990, c. E.23, s. 52, as am. by S.O. 1998,

2000 CanLII 16946 (ON CA)

c. 18, Sch. G, s. 50

Rules and regulations referred to

Rules of Civil Procedure, R.R.O. 1990, Reg. 194, rules 31.07, 31.09, 31.11, 51.05, 53.03, 53.08

Rules of Professional Conduct, Rule 10

Authorities referred to

Holmested and Gale, Ontario Judicature Act and Rules of Practice (Scarborough, Ont.: Carswell, 1983), p. 1767
Sopinka, Lederman and Bryant, The Law of Evidence in Canada, 2d ed. (Toronto: Butterworths, 1999), pp. 940, 1051-53
Watson and Perkins, Holmested and Watson: Ontario Civil Procedure (Toronto: Carswell, 1984), 3125, 3126

APPEAL from a judgment dismissing an action for negligence against a doctor, three nurses and a hospital.

Barry A. Percival, Q.C., Martin Wunder, Q.C., and Ronald D. Davis, for appellants.
Joshua Liswood and Kathryn M. Frelick, for respondents, The Public General Hospital Society of Chatham, A. Olson, P. Colebrook and M. Want.
W. Niels F. Ortved and J. Thomas Curry, for respondent, G. Asher.

[1] BY THE COURT: -- In July 1990, Barbra and Allen Marchand were expecting their first child. Barbra's pregnancy had been relatively uneventful. However, by July 10 she was 16 days beyond her due date and her obstetrician, Dr. G. Asher, arranged for her to be induced the next day at the Public General Hospital in Chatham.

[2] Mrs. Marchand was admitted to the Hospital at 1:05 a.m. on July 11. At 8:32 that morning her son Joel was delivered by

2000 CanLII 16946 (ON CA)

emergency Caesarean section performed by Dr. Asher.

[3] Tragically, Joel was born profoundly disabled. He suffered asphyxia as a fetus with the result that the cells in the cortex of his brain were destroyed. He cannot walk or talk and will be entirely dependent on others for his care throughout his life.

[4] In this action Joel and his parents sued Dr. Asher, the Hospital and three of the Hospital nurses, claiming that their negligence caused Joel's condition.

[5] The trial began on October 18, 1993. It was anticipated to run for six to eight weeks. In the end it took 165 court days to complete. The trial was characterized by an extraordinary level of rancour and hostility on the part of counsel, all of whom were, regrettably, senior members of the bar of Ontario. It was not a trial of which the administration of justice can be proud.

[6] On October 7, 1996, Granger J. released his reasons for judgment dismissing the action. This is the appeal by Joel and his parents from that decision.

[7] The appellants make three broad attacks on the trial judgment.

[8] First, the appellants argue that the trial judge erred in declining to find that the respondents were negligent in not properly monitoring Mrs. Marchand's pregnancy and in not delivering Joel earlier.

[9] Second, the appellants argue that they did not receive a fair trial because of the erroneous and one-sided evidentiary rulings made by the trial judge.

[10] Third, the appellants argue that the trial judge's conduct of the trial raised a reasonable apprehension of bias towards them. They submit that the trial judge failed to restrain or control the unprofessional conduct of defence counsel throughout the entire trial.

2000 CanLII 16946 (ON CA)

[11] We will deal with each of these issues in turn.

I. WERE THE RESPONDENTS NEGLIGENT?

[12] In this court the appellants relied on a series of acts and omissions by Dr. Asher and the Hospital nurses, which they argued were negligent and which they claimed led to Joel's tragedy. These acts and omissions all relate to the final stages of Mrs. Marchand's pregnancy as it stretched beyond her due date into its forty-first and forty-second weeks.

[13] The appellants described the four components of this "cumulative negligence" as follows:

(a) failing to instruct Mrs. Marchand about the importance of fetal kick count as an indicator of fetal health;

(b) improperly administering and interpreting the non-stress test given to Mrs. Marchand on July 5;

(c) thereafter failing to retest, monitor, or induce Mrs. Marchand; and

(d) failing to attach a fetal heart monitor once Mrs. Marchand was admitted to the hospital on July 11.

[14] At trial, Granger J. considered and rejected each of these arguments.

[15] The appellants also challenge the finding made by the trial judge that the tragedy which befell Joel was caused not by any act or omission of the respondents, but by a sudden abruption or rupture of the placenta pulling away from the uterine wall. The trial judge found that this began without warning at about 7:40 a.m. on July 11, resulting in cataclysmic oxygen deprivation to Joel's brain before his birth some 50 minutes later. On appeal the appellants raised no allegations of negligence relating to the treatment of Joel from 7:40 a.m. onwards.

2000 CanLII 16946 (ON CA)

[16] We did not find it necessary to call on the respondents to respond to any of these arguments. There was ample evidence before the trial judge to support both his finding that none of the acts of negligence had been established and his determination of the cause of the tragedy that befell Joel. Nonetheless, we will briefly review each of the arguments.

1. Allegations of "Cumulative Negligence"

[17] First, the appellants allege that Dr. Asher was negligent in failing to advise Mrs. Marchand of the significance of reduced fetal movement as her pregnancy went beyond term. However, the trial judge found as a fact that Dr. Asher did indeed have a complete discussion with her concerning fetal movement. Equally important, the trial judge found that Mrs. Marchand reported no significant reduction in fetal movement to Dr. Asher and that any reduction she experienced was a natural consequence of the fetus entering the birth canal and therefore of no moment. These findings are amply supported in the evidence and ought not to be disturbed.

[18] Second, the appellants allege negligence in connection with the non-stress test ("NST") administered to Mrs. Marchand on July 5 to determine the health of her fetus. They say that Nurse Olson was negligent in administering the NST and in interpreting the results to show a healthy fetus, and that Dr. Asher was negligent in failing to review the results himself or failing to have them reviewed by another professional.

[19] Again, however, the findings of the trial judge are to the contrary and are well founded in the evidence. He found that Nurse Olson administered the test properly. Indeed there was no evidence to the contrary. The trial judge also found that she was correct in interpreting the results of the test to indicate a healthy fetus, a conclusion which accorded with the predominant view of the expert witnesses called at trial. While several of the appellants' experts found the test results raised a suspicion, the trial judge correctly concluded that even this could render Nurse Olson's conclusion no more than an error in judgment falling short of negligence. Finally, although the trial judge found that Dr. Asher should have

2000 CanLII 16946 (ON CA)

reviewed the NST results himself, he also found that the doctor would have reached the same conclusion as Nurse Olson (which he found to be the correct conclusion) that the test result was normal. Therefore, the course of Mrs. Marchand's pregnancy would not have changed had Dr. Asher reviewed the NST results himself.

[20] The appellants' third allegation of negligence is that Dr. Asher fell below the required standard of care in failing to intervene in Mrs. Marchand's pregnancy until July 10, when he scheduled an induction for the next day.

[21] In addressing this argument the trial judge conducted a careful review of the expert evidence on standard of care called by both sides. He was careful to address himself to the standard required of obstetricians practising in Ontario in July and August 1990. He concluded on the basis of ample evidence that where, as here, the pregnancy was normal and there was no indication of fetal distress, it was entirely acceptable practice to do without serial anti-natal monitoring and to schedule the induction when Dr. Asher did. There is no basis to interfere with that conclusion.

[22] Finally, the appellants allege negligence in the failure of nursing staff to attach a fetal heart monitor to Mrs. Marchand following her admission to the Hospital at 1:05 a.m. on July 11. Nurse Colebrook did not do this but monitored the fetal heart rate intermittently with the use of a stethoscope. That monitoring detected no abnormality before 7:40 a.m.

[23] Once again the trial judge carefully reviewed and considered the expert evidence. He concluded that in the circumstances the nursing decision to monitor the fetal heart rate by stethoscope rather than by attaching a fetal heart monitor met an acceptable standard of care. This was particularly so given that the monitoring results indicated that the fetus was not in distress before 7:40 a.m. The record amply supports this finding and we would not interfere with it.

[24] In summary, the trial judge concluded that none of the components of the cumulative negligence advanced by the

2000 CanLII 16946 (ON CA)

appellants were made out on the evidence. In our view, this conclusion is unassailable.

2. Causation

[25] The appellants also attack the finding of causation made by the trial judge. He rejected their assertion at trial that Joel's asphyxia was due to a long slow deterioration of the placenta, which could have been detected by proper care. Rather, he found that the fetus was assaulted by a sudden placental abruption, which commenced without warning about 7:40 a.m. and which resulted in critical oxygen deprivation to the fetus until Joel was delivered at 8:32 a.m.

[26] Here, as well, the finding of the trial judge is well supported in the evidence. It cannot be said in any way to be unreasonable. The trial judge carefully reviewed the evidence. He recognized that much of the evidence describing an abruption came from Dr. Asher himself. There was also, however, significant corroborating evidence, particularly the testing of the relevant blood gases. That clinical evidence supported the conclusion that an acute event, which had its onset at about 7:40 a.m. and evolved rapidly thereafter, caused Joel's profound injuries.

[27] The conclusion about what happened to Joel was carefully drawn after a review of all the evidence. It is a reasonable conclusion, which we must accept. A severe spontaneous placental abruption, not anything done by the respondents, caused this tragedy.

II. DID THE APPELLANTS RECEIVE A FAIR TRIAL?

[28] The appellants submit that, taken cumulatively, a number of evidentiary rulings by the trial judge as well as the trial judge's uneven application of his evidentiary rulings (a) denied the appellants the opportunity fairly to present their case or, (b) created a reasonable apprehension of bias on the part of the trial judge. In their factum, the appellants submit that the impugned rulings "distorted the trial process", "impaired any reasonable attempt to achieve justice" and

2000 CanLII 16946 (ON CA)

"negated the Marchands' right to present their case fully". The appellants made similar oral submissions.

[29] We do not understand the appellants to say that any one of the evidentiary rulings, standing on its own, would be sufficient to warrant interference by this court. Rather, it is their position that we must consider whether the overall, cumulative effect of these rulings denied the appellants a fair trial. We will review each impugned ruling individually to assess whether the cumulative complaint the appellants advance has any substance.

A. Evidentiary Rulings

1. Ruling limiting expert evidence to the "substance" of the report

[30] During the examination-in-chief of Dr. Fields, an expert witness called by the appellants, their counsel asked about indications of late decelerations on the NST strip. Counsel for the respondents objected on two grounds: first, rule 31.07(1), which prevents a party from introducing information at trial where he or she has refused to furnish the information on discovery; and second, rule 53.03(1), which requires a party to serve an expert's report setting out the substance of the expert's proposed testimony. On examination for discovery, counsel for the respondents had asked that the location of late decelerations be identified on the NST strip. Appellants' counsel refused to provide that information. Although the appellants filed a report from Dr. Fields, the report merely described the NST strip as abnormal and suspicious.

[31] The trial judge ruled that the appellants had failed to comply with both rules 31.07 and 53.03. However, applying rule 53.08, the trial judge allowed Dr. Fields to testify about indications of late decelerations on the NST strip on the ground that counsel for the respondents would have sufficient time to prepare their cross-examination of Dr. Fields. In making this ruling, he cautioned counsel for the appellants (and to a lesser extent counsel for the respondents) that, at some point, attempts to examine experts on matters outside

2000 CanLII 16946 (ON CA)

their reports would cause prejudice to the other side requiring the exclusion of testimony.

[32] The appellants' counsel proceeded to examine Dr. Fields extensively on the NST strip. He then began to examine Dr. Fields on the relationship between oxygen deprivation and fetal reserve, and specifically about bradycardia (abnormally slow heart rate). Counsel for the respondents objected on the ground that the concept of bradycardia appeared nowhere in Dr. Fields' report. The appellants' counsel argued that the report dealt with the standard of care in treating an overdue mother, and that the questions went to signs of fetal distress some hours before the delivery. The trial judge ruled that the appellants' counsel could not pursue the "bradycardia" line of questioning because Dr. Fields' report made no mention of when fetal distress was determined.

[33] The appellants submit that Dr. Fields should have been permitted to explain what bradycardia means because bradycardia is a sign of fetal distress, and fetal distress appeared in the report. They contend that the trial judge erred in adopting an unduly narrow construction of rule 53.03, specifically with respect to the phrase "the substance of his or her proposed testimony". In particular, the appellants submit that the trial judge erred in equating "substance" with "summary". Indeed, in their factum, the appellants submit that "the Marchands' expert witnesses were constrained to testifying verbatim from the contents of their reports". It is the appellants' submission that this ruling set an erroneously high standard for what is required in an expert report and impeded the presentation of their case.

[34] Rule 53.03 governs expert opinion evidence. At the time of trial, rule 53.03 provided:

> 53.03 (1) A party who intends to call an expert witness at trial shall, not less than ten days before the commencement of the trial, serve on every other party to the action a report, signed by the expert, setting out his or her name, address and qualifications and the substance of his or her proposed testimony.

2000 CanLII 16946 (ON CA)

(2) No expert witness may testify, except with leave of the trial judge, unless subrule (1) has been complied with. [See Note 1 at end of document]

Unless a party has fully complied with the requirements set out in rule 53.03(1), an expert witness called by that party may not testify except with leave.

[35] This court considered the meaning of the "substance" of the proposed testimony of an expert in Thorogood v. Bowden (1978), 21 O.R. (2d) 385, 89 D.L.R. (3d) 604 (C.A.). A medical expert retained by the plaintiff in a personal injury action submitted a report indicating that the injuries would manifest in more intensive symptoms later in life. At trial, the plaintiff's medical expert gave evidence about the possibility of arthritis and the future need for an artificial hip. On appeal, the defendant argued that the trial judge ought to have declared a mistrial, as the matters raised by the expert had not been included in his medical reports. The court dismissed the appeal. Lacourcire J.A., writing for the majority, reasoned as follows at p. 386 O.R.:

> We interpret the law with respect to medical reports to be that a medical expert is not to be narrowly confined and limited to the precise contents of his report, but he has a right to explain and amplify. What was done here, in our view, . . . was to expand on what was latent in the medical report, and it did not open a new field. In our view, the trial Judge properly concluded that there was no prejudicial surprise here and, therefore, exercised his discretion and properly refused to declare a mistrial.

[36] Thorogood was applied in Auto Workers' Village (St. Catherines) Ltd. v. Blaney, McMurtry, Stapells, Friedman (1997), 14 C.P.C. (4th) 152 (Ont. Gen. Div.). The plaintiff alleged, among other things, that the solicitors were negligent and caused the plaintiff damages in connection with a condominium project. The plaintiff called a lawyer to give expert opinion evidence in the area of condominium development. During examination in-chief, the witness opined that a clause

2000 CanLII 16946 (ON CA)

in an agreement might be void. The defendants objected to this line of questioning on the ground that it went beyond the expert's report. Quinn J. ruled that the expert could not testify about the validity of the clause, as that opinion was not stated in his report. Quinn J. relied on Thorogood and found, at p. 157, that the impugned questioning entered a new field:

> The opinion [by the expert], as to the voidness of the price-escalation clause, creates a discrete instance of solicitors' negligence: one which had never before been raised by the plaintiff. In other words, it opens up a new field. It is neither touched upon nor latent in the report of [the expert]. Therefore, the report does not contain "the substance" of the "proposed testimony" on the issue of voidness, as required by subrule 53.03(1).

See also Iler v. Beaudet, [1971] 3 O.R. 644 (Co. Ct.); McEachrane v. Children's Aid Society of Essex (County) (1986), 10 C.P.C. (2d) 265 (Ont. H.C.J.).

[37] Ollet v. Bristol Aerojet Ltd., [1979] 3 All E.R. 544 (Q.B.) dealt with an action for personal injuries suffered in connection with some machinery. An expert witness filed a report merely setting out a factual description of the machine and the alleged circumstances in which the accident happened. Ackner J. considered the English equivalent of rule 53.03 and found that the report failed to comply with the requirement that the parties exchange the substance of the expert's proposed testimony. He interpreted the term "substance" in light of the function of expert evidence, stating at p. 544:

> . . . An expert, unlike other witnesses, is allowed, because of his special qualifications and/or experience, to give opinion evidence. It is for his opinion evidence that he is called, not for a factual description of the machine or the circumstances of the accident, although that is often necessary in order to explain and/or justify his conclusions. When the substance of the expert's report is to be provided, that means precisely what it says, both the substance of the factual description of the machine and/or the circumstances

2000 CanLII 16946 (ON CA)

of the accident and his expert opinion in relation to that accident, which is the very justification for calling him.

[38] In our view, these cases indicate that the "substance" requirement of rule 53.03(1) must be determined in light of the purpose of the rule, which is to facilitate orderly trial preparation by providing opposing parties with adequate notice of opinion evidence to be adduced at trial. Accordingly, an expert report cannot merely state a conclusion. The report must set out the expert's opinion, and the basis for that opinion. Further, while testifying, an expert may explain and amplify what is in his or her report but only on matters that are "latent in" or "touched on" by the report. An expert may not testify about matters that open up a new field not mentioned in the report. The trial judge must be afforded a certain amount of discretion in applying rule 53.03 with a view to ensuring that a party is not unfairly taken by surprise by expert evidence on a point that would not have been anticipated from a reading of an expert's report.

[39] We are unable to conclude that the trial judge erred in his ruling. Although we do not have a copy of his report, it appears from the transcripts that Dr. Fields' report merely stated his conclusion that the appropriate standard of care was to attach a fetal heart monitor on admission to indicate fetal distress at the earliest possible point. Dr. Fields' report did not refer to bradycardia, did not state the point at which fetal distress was determined, and did not deal with the "reserve capacity" that the fetus might have had.

[40] Moreover, the trial judge had ruled that Dr. Fields had expertise only with regard to the standard of care in Michigan. Dr. Fields' report dealt with the topic of fetal distress in connection with his opinion on the standard of care. The appellants' counsel, however, sought to elicit from Dr. Fields, through the bradycardia questions, evidence going to causation. Thus, the bradycardia evidence was directed to an issue not addressed in the report. Accordingly, even if the trial judge erred in his interpretation of rule 53.03, no prejudice arises from that error as Dr. Fields had not been qualified to give expert evidence about causation.

2000 CanLII 16946 (ON CA)

2. Denial of request for adjournment

[41] In the light of the trial judge's ruling restricting Dr. Fields to the "substance" of his report, the appellants requested an adjournment for a "couple of weeks" to obtain supplementary reports from other witnesses they intended to call to give expert evidence. In particular, the appellants sought to obtain a supplementary report from Dr. Silver, whose original report was less than one page and dealt only with the issue of abruption. Counsel for the respondents opposed the request, arguing that the appellants were seeking an opportunity to "re-do the liability case", and that if the request was allowed, the respondents were entitled to a further examination for discovery.

[42] The trial judge refused the appellants' request for an adjournment. He clarified the effect of his ruling concerning Dr. Fields' report, stating that it "is not a general ruling throughout the trial. It does not apply to all the reports. It only replies to the evidence that I heard from Dr. Fields yesterday and the way the evidence was developed." The trial judge emphasized the need to proceed with the trial, noting that counsel for the respondents would be entitled to a further examination for discovery if the experts were allowed to file further reports, thus unduly delaying the completion of the case.

[43] Although the appellants did not specifically address the reasons why the denial of their request for an adjournment was in error, they submit that the Fields ruling required them to revisit every report submitted by their liability experts. The denial of an adjournment, they say, prevented them from fully and fairly presenting their case.

[44] In our view, the trial judge did not act improperly in refusing to grant the request for an adjournment. The trial judge made it clear that the Fields ruling applied only to Dr. Fields, and that he would deal with issues concerning the adequacy of other expert reports as they arose. The trial judge emphasized the need to continue with the trial. This need was

2000 CanLII 16946 (ON CA)

properly emphasized, given that: the parties were then several weeks into the trial; there had been substantial discovery prior to the trial; and the filing of additional reports would necessitate further examinations for discovery, thus prolonging the trial. The denial of an adjournment did not cause any injustice in this case.

3. Ruling preventing Dr. Silver from testifying on her second report

[45] The appellants called Dr. Silver, a pathologist at the Toronto Hospital for Sick Children, as an expert witness. Dr. Silver had prepared a report dated April 22, 1993. Following the Fields ruling, the appellants obtained a further report from Dr. Silver. Dr. Silver's second report was served on November 24, 1993. The respondents were not advised of the substance of Dr. Silver's additional evidence before being served with this report. The respondents objected to Dr. Silver testifying on matters raised in the second report on the grounds that: (a) the second report set out a new theory of causation; and (b) allowing Dr. Silver to testify in accordance with the second report would cause prejudice to the respondents as Dr. Manning, an expert in fetal medicine called by the appellants, had already testified and the respondents would be denied the opportunity to cross-examine him on the new theory.

[46] The trial judge ruled that he would not grant leave for Dr. Silver to give evidence about matters set out in the second report. The trial judge described the first report of Dr. Silver, which stated that the presence of meconium within the fetal membrane provided evidence of fetal distress, as extremely short. In contrast, the second report was over three pages long, and largely devoted to explaining the reasons for Dr. Silver's opinion about why a placental abruption could not have resulted in severe birth asphyxiation.

[47] The trial judge commented on the two reports as follows:

> . . . I simply do not accept the argument that the report of April 22nd, 1993 would allow Dr. Silver to give the evidence as set out in her report dated November 23, 1993. Mr. Wunder

2000 CanLII 16946 (ON CA)

> is attempting to do with Dr. Silver exactly what I had ruled he could not do with Dr. Fields, which is, to just state a conclusion in a report and attempt to explain in the evidence the reason for the conclusion. The reason should be in the report so opposing counsel will know such reasoning and can test it by cross-examining other expert witnesses.

[48] The trial judge then considered whether rule 53.08 obliged him to grant leave for Dr. Silver to give evidence as proposed. The trial judge agreed that the respondents would suffer prejudice if Dr. Silver was allowed to give the proposed testimony. Dr. Manning had completed his testimony, and the respondents would be unable to cross-examine Dr. Manning on Dr. Silver's second report. Accordingly, the respondents' right to a full and fair defence would be impaired. The trial judge found that requiring Dr. Manning to return for further cross-examination would result in undue delay. Given these considerations, the trial judge refused to grant leave.

[49] We do not agree that the trial judge erred in denying leave to permit Dr. Silver to testify about matters in her second report for three reasons.

[50] First, the appellants sought to elicit Dr. Silver's opinion that severe birth asphyxiation could not have resulted from an abruption. The first report did not deal with abruption; this report concerned the presence of meconium as an indication of fetal distress. Accordingly, testimony on abruption would certainly "open up a new field" not covered in the first report.

[51] Second, the trial judge found that the respondents would be prejudiced as they had been unable to cross-examine Dr. Manning about Dr. Silver's second report and that requiring Dr. Manning to re-attend would cause undue delay. This was a matter within the discretion of the trial judge and we see no basis to interfere.

[52] Third, Dr. Silver, ultimately, did testify about her opinion that an abruption was not the cause of Joel Marchand's injuries.

2000 CanLII 16946 (ON CA)

[53] We add that the appellants could have avoided the very problem they encountered with respect to the evidence of Dr. Silver. They had gone to trial on a one-page report from a witness they considered important and should not have been surprised when it proved inadequate. When it did, they took no steps to advise the respondents to expect the amplified report they had asked Dr. Silver to prepare.

4. "Foundational facts" rulings

[54] On November 4, 1993, the appellants entered as Exhibit 47 ("Ex. 47") a report written by two home care experts, Ms. Kelly and Ms. Snell, dated August 19, 1993. Ex. 47 listed various source documents, including numerous reports from medical practitioners involved in the care of Joel Marchand. Counsel for Dr. Asher stated that he understood the appellants to be undertaking to call the authors of Ex. 47 and also to prove the source documents. The trial judge responded that the appellants would have to produce their source documents. The appellants' counsel gave no indication that he would not prove the source documents.

[55] On November 24, 1993, the appellants served a letter advising that Ms. Kelly and Ms. Snell would no longer be relying on the medical reports referred to in Ex. 47; instead, the two witnesses would be relying on videos filed at trial. The respondents objected to Ms. Kelly giving opinion evidence on a basis other than the medical reports. The respondents' counsel argued that the appellants had undertaken to prove the medical opinions contained in these reports. The respondents' counsel further argued that Ms. Kelly's evidence was of no probative value as there was no admissible evidence proving the factual foundation of her opinion.

[56] The trial judge accepted the respondents' submissions and ruled that Ms. Kelly's opinion lacked probative value unless the appellants proved the facts on which she based her opinion (the "foundational facts ruling"). The trial judge acknowledged that the appellants might prove Joel's disability in a number of ways, but noted that "if [Ms. Kelly's] opinion

2000 CanLII 16946 (ON CA)

is based on the opinions of doctors then the plaintiff must attempt to prove the opinions of such doctors. . .". The trial judge also found that the appellants' counsel's refusal to prove the medical reports referred to in Ex. 47 breached an implied undertaking to prove the opinions of the medical doctors referred to in Ex. 47.

[57] Given the breach of this implied undertaking, the trial judge stated that he did "not intend to give Ex. 47 any weight whatsoever". As the respondents did have notice of the substance of Ms. Kelly's evidence, the trial judge was prepared to allow Ms. Kelly to testify. However, he stated that he would insist that all of the facts on which Ms. Kelly relied be proved by some admissible evidence before he would permit Ms. Kelly to state her opinion.

[58] A similar issue arose later on May 19, 1994. The appellants proposed to call Ms. Staub to give opinion evidence regarding the future care costs for Joel Marchand. Ms. Staub had written a report dated September 13, 1993, which had been filed as an exhibit on an implied undertaking that the appellants would prove the facts on which the report was based. The respondents objected to Ms. Staub being allowed to give evidence on the ground that the appellants had failed to prove the foundational facts. The appellants' counsel suggested that the earlier foundational facts ruling was unclear, and submitted that the foundational facts ruling allowed him to prove the foundational facts upon which Mr. Staub's opinion was based in a manner different than that set out in her written report. The trial judge reiterated that the effect of the foundational facts ruling was that if a report was based on the reports of doctors, the opinion of the doctors must be proven.

[59] The trial judge also referred to an earlier ruling requiring counsel to file a list of the expert witnesses they intended to call or whose reports would be filed under s. 52 of the Ontario Evidence Act, R.S.O. 1990, c. E.23. He also ruled that before an expert could testify a voir dire be held in order to determine the facts or opinions that the expert relied on in forming his or her opinion.

2000 CanLII 16946 (ON CA)

[60] In R. v. Lavallee, [1990] 1 S.C.R. 852, 55 C.C.C. (3d) 97, the Supreme Court of Canada reviewed the circumstances in which expert opinion evidence may be admitted, notwithstanding that the opinion is based upon hearsay evidence. Wilson J. reviewed the Supreme Court's prior decision in R. v. Abbey, [1982] 2 S.C.R. 24, 68 C.C.C. (2d) 394, and at pp. 127-28 C.C.C. [p. 893 S.C.R.] interpreted Abbey as standing for the following propositions:

> 1. An expert opinion is admissible if relevant, even if it is based on second-hand evidence.
>
> 2. This second-hand evidence (hearsay) is admissible to show the information on which the expert opinion is based, not as evidence going to the existence of the facts on which the opinion is based.
>
> 3. Where the psychiatric evidence is comprised of hearsay evidence, the problem is the weight to be attributed to the opinion.
>
> 4. Before any weight can be given to an expert's opinion, the facts upon which the opinion is based must be found to exist.

Thus, Lavallee establishes that an expert opinion based upon hearsay will be admissible; however, the weight to be attached to that opinion is an issue.

[61] Wilson J. clarified the fourth proposition, and rejected the proposition that every fact relied upon by the expert must be independently proven before any weight could be attached to an expert opinion. She stated at pp. 130-31 C.C.C. [pp. 896-97 S.C.R.]:

> . . . Abbey does not, in my view, provide any authority for that proposition. The court's conclusion in that case was that the trial judge erred in treating as proven the facts upon which the psychiatrist relied in formulating his opinion. The solution was an appropriate charge to the jury, not an effective withdrawal of the evidence. In my view, as long as there is some admissible evidence to establish the

2000 CanLII 16946 (ON CA)

foundation for the expert's opinion, the trial judge cannot subsequently instruct the jury to completely ignore the testimony. The judge must, of course, warn the jury that the more the expert relies on facts not proved in evidence the less weight the jury may attribute to the opinion.

. . . . .

Where the factual basis of an expert's opinion is a mlange of admissible and inadmissible evidence the duty of the trial judge is to caution the jury that the weight attributable to the expert testimony is directly related to the amount and quality of admissible evidence on which it relies.

[62] Sopinka J., in a concurring judgment, noted that the principles underlying Abbey give rise to a contradiction: an expert opinion based entirely on hearsay will be admissible, but will be entitled to no weight. He provided the following resolution at pp. 132-33 C.C.C. [p. 899-900 S.C.R.]:

The resolution of the contradiction inherent in Abbey, and the answer to the criticism Abbey has drawn, is to be found in the practical distinction between evidence that an expert obtains and acts upon within the scope of his or her expertise (as in City of St. John), and evidence that an expert obtains from a party to litigation touching a matter directly in issue (as in Abbey.)

In the former instance, an expert arrives at an opinion on the basis of forms of enquiry and practice that are accepted means of decision within that expertise. A physician, for example, daily determines questions of immense importance on the basis of the observations of colleagues, often in the form of second or third-hand hearsay. For a court to accord no weight to, or to exclude, this sort of professional judgment, arrived at in accordance with sound medical practices, would be to ignore the strong circumstantial guarantees of trustworthiness that surround it, and would be, in my view, contrary to the approach this court has taken to the analysis of hearsay evidence in general, exemplified in Ares v. Venner (1970), 14 D.L.R. (3d) 4 [(S.C.C.)]. In R. v.

2000 CanLII 16946 (ON CA)

> Jordan (1984), 11 C.C.C. (3d) 565 (B.C.C.A.), a case concerning an expert's evaluation of the chemical composition of an alleged heroin specimen, Anderson J.A. held, and I respectfully agree, that Abbey does not apply in such circumstances: see also R. v. Zundel (1987), 31 C.C.C. (3d) 97 at p. 146 (Ont. C.A.), where the court recognized an expert opinion based upon evidence ". . . of a general nature which is widely used and acknowledged as reliable by experts in that field".
>
> Where, however, the information upon which an expert forms his or her opinion comes from the mouth of a party to the litigation, or from any other source that is inherently suspect, a court ought to require independent proof of that information. The lack of such proof will, consistent with Abbey, have a direct effect on the weight to be given to the opinion, perhaps to the vanishing point. But it must be recognized that it will only be very rarely that an expert's opinion is entirely based upon such information, with no independent proof of any of it. Where an expert's opinion is based in part upon suspect information and in part upon either admitted facts or facts sought to be proved, the matter is purely one of weight. . . .

(Parallel citations omitted)

[63] This court considered the weight to be given to an expert opinion based solely upon hearsay evidence in R. v. Scardino (1991), 6 C.R. (4th) 146, 46 O.A.C. 209 (C.A.). The accused appealed from his conviction for second degree murder. At trial, the accused led expert evidence from a psychiatrist, who testified that the accused suffered from a psychiatric disorder that would have prevented him from appreciating the nature and quality of his acts. Among the evidence relied upon by the expert in forming his opinion was a factual account of the events recounted by the accused. The trial judge instructed the jury that these matters had not been established in evidence, and thus the "degree to which [the expert's] opinion is dependent upon those statements attributed to the accused is of no weight . . .". Finlayson J.A. found that the trial judge had not erred in her charge to the jury, stating at p. 153 C.R.

2000 CanLII 16946 (ON CA)

that "[a]n expert's opinion is admissible in evidence, notwithstanding the absence of proof in some areas relied upon by the expert. However, the weight to be given to the opinion in such cases is diminished, sometimes to the point where the opinion can be given no weight at all." This general proposition was reaffirmed by this court in R. v. Grosse (1996), 29 O.R. (3d) 785, 107 C.C.C. (3d) 97 (C.A.), where this court indicated that an expert opinion based entirely upon inadmissible evidence would itself be entitled to no weight and therefore could not be accepted by the trial judge.

[64] It is clear from the Supreme Court's decision in Lavallee that proof of foundational facts goes to the weight to be accorded to the opinion rather than its admissibility. It follows that, taken in isolation, the appellants' unwillingness to prove in evidence the medical reports upon which they had relied was not a sufficient reason to preclude Ms. Kelly and Ms. Staub from testifying.

[65] The trial judge based his refusal to admit the evidence on his finding that the evidence would have no weight. Ordinarily, this is not the appropriate approach. The question of weight can only be assessed at the close of a party's case; it cannot be assessed prior to an expert witness giving testimony. Further, it is not the law that a party must prove the identical factual foundation relied upon by an expert in formulating an opinion. Indeed, the Supreme Court clearly rejected that proposition in Lavallee.

[66] However, it appears to us that the issues in the case at bar were more complex. The appellants sought to rely upon videotapes as the foundation for the opinions of Ms. Kelly and Ms. Staub rather than the medical reports that served as the basis for the Kelly and Staub reports. The trial judge characterized the matter as an attempt by the appellants to rely upon a different set of facts from the facts that served as a basis for the experts' reports.

[67] While a party might prove the same set of facts from alternative sources, it must also be the case that a party cannot rely upon a different set of facts. This proposition is

2000 CanLII 16946 (ON CA)

merely a variation of the basic rule articulated in Lavallee: insofar as a party fails to prove those facts relied upon by an expert in forming his or her opinion, the expert opinion will be entitled to little or no weight.

[68] We are not persuaded that, in light of all the factors before the trial judge, he erred in his approach to the problem he faced. The foundational facts ruling has to be considered in the context of a long and difficult trial and in relation to the trial judge's efforts to manage that trial in an efficient manner. The appellants were in breach of an undertaking and were refusing to prove in evidence the factual foundation of the opinion. It was open to the trial judge to conclude that the observations and conclusions could not be established in any way other than by adducing the medical reports containing those observations and conclusions. The videotapes could only provide evidence of Joel Marchand's present capabilities; they could say nothing about Joel Marchand's future development. The appellants' refusal to prove the medical reports provided a sufficient basis for the trial judge to conclude that the experts' opinions would be entitled to no weight. Given the protracted nature of the tri al and the explicit position taken by the appellants as to what they would and would not prove, we would not interfere with the trial judge's decision not to hear evidence that would be given no weight.

[69] Even if the trial judge did err, the error resulted in no substantial wrong or miscarriage of justice. The opinions of Ms. Kelly and Ms. Staub were entitled to little or no weight, given that the factual foundations of their reports had not been proved in evidence. Even if the trial judge had heard the proposed testimony, he could not have accepted it. Finally, this evidence pertained only to damages and would have had no impact on the trial judge's liability findings.

5. Ruling allowing the respondents to correct Dr. Asher's discovery admission

[70] On examination for discovery, the appellants' counsel asked Dr. Asher a number of questions relating to his observations of amniotic fluid during Mrs. Marchand's Caesarean

2000 CanLII 16946 (ON CA)

section. The relevant questions and answers are reproduced below. The most important is Q. 596 and Dr. Asher's "admission" of oligohydramnios.

594 Q. Am I correct that at birth this child was observed to suffer the symptoms of oligohydramnios?

A. At birth there was very little amniotic fluid.

595 Q. So am I correct, that's a diagnosis of oligohydramnios?

A. That is the diagnosis, but you said symptoms, didn't you?

596 Q. Sorry. Am I correct this child showed oligohydramnios at birth?

A. Yes.

. . . . .

792 Q. . . . May I take it there was some amniotic fluid?

A. Yes.

793 Q. You have told me very little?

A. I said scant I believe.

. . . . .

801 Q. Would you describe the amount of amniotic fluid? Your report says "very little". You told me today, "scant". Are you able to give me some graphic description of how much? Just a couple of drops . . .

A. No, it would be approximately 300 c.c.'s.

802 Q. And what would the normal amount be?

A. It would be as much as 800 c.c.

2000 CanLII 16946 (ON CA)

. . . . .

810 Q. Am I correct, your record -- your Operative Record does not disclose that there was 300 c.c.'s of amniotic fluid?

A. No, that's a recollection.

811 Q. Okay, so I suggest to you that it could have been 150.

A. You can suggest what you want. My recollection is approximately 300 c.c.'s.

812 Q. No, you're the one who is testifying and yes, I can suggest what I want as long as it's not irresponsible . . .

A. Yes.

813 Q. . . . and I just want . . .

A. Well, I think it's a little -- 150 is a big difference at that level.

814 Q. I understand. Could it have been 200, sir?

A. It wasn't measured so I can't tell you absolutely.

815 Q. So we can't be absolute about the 300.

A. No.

816 Q. And so I suggest to you it could have been 200.

A. No.

817 Q. You think it was more than that.

A. Yes.

[71] After the trial had commenced, counsel for the

2000 CanLII 16946 (ON CA)

respondents sent the appellants' counsel a letter correcting a number of the answers given by Dr. Asher on discovery, and withdrawing the "admission" of oligohydramnios. The corrections relevant for present purposes are as follows:

> 596 Q. Sorry. Am I correct this child showed oligohydramnios at birth?
>
> A. There was no oligohydramnios at birth. For a 42-week gestation the amniotic fluid would normally be approximately 250 to 300 cc.
>
> . . . . .
>
> 801 Q. You reported very little, you told me today scant. Are you able to give me some graphic description of how much, just a couple of drops?
>
> A. No, it would be approximately 300 cc.
>
> 802 Q. And what would the normal amount be?
>
> A. An amniotic fluid volume of 800 cc's would be normal for approximately 40 weeks gestation.

[72] The appellants' counsel objected to the trial judge granting leave for Dr. Asher to correct the answers that he gave on discovery. The appellants argued that they relied on Dr. Asher's "admission" of oligohydramnios and would be prejudiced in the presentation of their case if Dr. Asher changed his admission. The appellants' counsel submitted that Rule 31.09(1) requires a party to correct any incorrect or incomplete answers "forthwith", and that the respondents had failed to comply with this requirement. The appellants' counsel also argued that Dr. Asher's corrections would have affected the examination in-chief of Dr. Manning (who had finished testifying) and would affect the examination in-chief of Dr. Johnson (who had been sent a number of Dr. Asher's discovery answers for consideration).

[73] The trial judge reserved his ruling, but did observe

2000 CanLII 16946 (ON CA)

that Dr. Asher's discovery answers would in any event have been subject to clarification by him either on examination-in-chief or on cross-examination. He also noted that, even if the corrections were allowed, the appellants' counsel would be able to cross-examine Dr. Asher extensively on any putative mistake. The trial judge did not make an explicit ruling allowing Dr. Asher to correct his answer on discovery, but he did allow the trial to proceed on the basis that Dr. Asher was free to testify that there was no oligohydramnios.

[74] On cross-examination, Dr. Asher gave the following explanation of his discovery answers and of his corrections:

> A. I was under the mistaken idea that 800 cc of amniotic fluid was, was normal for 42 weeks, and I was actually thinking of a term pregnancy which was 40 weeks, or a pregnancy at the due date which was 40 weeks as -- and actually that's -- the average volume at 40 weeks would be 800 cc, the average volume at 42 weeks would be somewhere between 250 and 300 cc.

[75] The appellants submit that the trial judge erred in allowing the respondents to correct the admission made by Dr. Asher during his examination for discovery and that prejudice inevitably flowed as the appellants' case was premised on an admission of oligohydramnios. The appellants also submit that they suffered prejudice in being required to cross-examine Dr. Asher on his admission and then the subsequent correction.

[76] In our view, the trial judge committed no error in permitting Dr. Asher to correct his discovery evidence for three reasons.

[77] First, Dr. Asher's original discovery answer was not a formal admission. As such, it was always open to him to explain his discovery answer in his testimony. In Sopinka, Lederman and Bryant, The Law of Evidence in Canada, 2d ed. (Toronto: Butterworths, 1999) at pp. 1051-53, the authors distinguish between formal and informal admissions. A formal admission is conclusive as to the matter admitted, and cannot be withdrawn except by leave of the court or the consent of the party in

2000 CanLII 16946 (ON CA)

whose favour it was made. The Law of Evidence states at pp. 1051-52 that a formal admission may be made in the following ways:

> (1) by a statement in the pleadings or by failure to deliver pleadings; (2) by an agreed statement of facts filed at the trial; (3) by an oral statement made by counsel at trial, or even counsel's silence in the face of statements made to the trial judge by opposing counsel with the intention that the statements be relied on by the judge; (4) by a letter written by a party's solicitor prior to trial; or (5) by a reply or failure to reply to a request to admit facts.

In contrast, an informal admission does not bind the party making it, if it is overcome by other evidence. That is, a party making an informal admission may later lead evidence to reveal the circumstances under which the admission was made in order to reduce its prejudicial effect.

[78] Dr. Asher's original discovery answer does not constitute a formal admission in the sense described in The Law of Evidence. We note as well that rule 51.05, governing the withdrawal of admissions requiring leave of the court, does not apply to an admission made on examination for discovery.

> 51.05 An admission made in response to a request to admit, a deemed admission under rule 51.03 [failure to respond to a request to admit] or an admission in a pleading may be withdrawn on consent or with leave of the court.

See G.D. Watson and C. Perkins, Holmested and Watson: Ontario Civil Procedure (Toronto: Carswell, 1984) at 3126.

[79] Second, rule 31.09 outlines a party's obligations with respect to information obtained subsequent to an examination for discovery. At the time of trial, rule 31.09 provided:

> 31.09 (1) Where a party has been examined for discovery or a person has been examined for discovery on behalf or in place of, or in addition to the party, and the party subsequently discovers that the answer to a question on the

2000 CanLII 16946 (ON CA)

examination,

(a) was incorrect or incomplete when made; or

(b) is no longer correct and complete,

the party shall forthwith provide the information in writing to every other party.

(2) Where a party provides information in writing under subrule (1),

(a) the writing may be treated at a hearing as if it formed part of the original examination of the person examined; and

(b) any adverse party may require that the information be verified by affidavit of the party or be the subject of further examination for discovery.

(3) Where a party has failed to comply with subrule (1) or a requirement under clause (2)(b), and the information subsequently discovered is,

(a) favourable to the party's case, the party may not introduce the information at the trial, except with leave of the trial judge; or

(b) not favourable to the party's case, the court may make such order as is just.

[80] Holmested and Watson, supra, describe at 3125 the obligation under rule 31.09 as an ongoing duty to correct and complete the answers given. In general, parties are entitled to correct their discovery answers. The impact of corrections is a matter to be decided by the trial judge, who is entitled to examine both the original and the amended answers: See Machado v. Pratt & Whitney Canada Inc. (1993), 17 C.P.C. (3d) 340 (Ont. Master); Capital Distributing Co. v. Blakey (1997), 33 O.R. (3d) 58, 147 D.L.R. (4th) 372 (Gen. Div.).

2000 CanLII 16946 (ON CA)

[81] Third is the combined effect of rules 31.09 and 53.08. Subrule 31.09(3)(a) provides that, where a party has failed to correct a discovery answer "forthwith", the party may not introduce the evidence except with leave. As noted above in the discussion of the ruling with respect to Dr. Silver, subrule 53.08(d) provides that, where evidence is admissible only with leave under subrule 31.09(3), the trial judge shall grant leave unless to do so will cause prejudice or undue delay. Accordingly, notwithstanding non-compliance with subrule 31.09(3), a trial judge must grant leave unless to do so would cause prejudice that could not be overcome by an adjournment or costs.

[82] With respect to the correction, subrule 31.09(2)(a) provides that a correction "may" be treated as forming part of the original examination. As there was no ruling on the correction, it is unclear whether the correction was, in fact, treated in that manner.

[83] There are circumstances in which a party will not be permitted to correct their discovery answers. In Burke v. Gauthier (1987), 24 C.P.C. (2d) 281 (Ont. H.C.J.), a personal injury action, the plaintiff sought to adduce evidence that his physical condition had substantially changed since his examination for discovery. The plaintiff had given no notice of the new evidence, and the respondents objected to its admission. Campbell J. began by describing the purpose of rule 31.09 at p. 285:

> The purpose of the provision is obvious. The parties prepare for trial on the basis of the evidence given at the discoveries. They assume that the answers given on discovery continue to be correct and complete, unless they are given information to the contrary. They figure out what they have to meet, decide how to prepare their own case, what investigations if any to undertake, what witnesses to call, what instructions to seek, and what kind of settlement might be reasonable, on the basis of the evidence given at the discoveries. If that evidence changes then there is a different case to meet. If the changes are not brought to the attention of the adverse party before trial he has no time or

2000 CanLII 16946 (ON CA)

> opportunity to investigate and prepare and consider the need for fresh medical examination and must meet a case different from the one that his opponent has led him to expect.

Campbell J. found that the new evidence changed the nature of the case the respondents had to meet. In considering whether to grant leave, he found that the plaintiff was well aware of the change, and that he had made no attempt to bring the new evidence to the defendant's attention. Accordingly, Campbell J. declined to grant leave. See also Bachalo v. Robson (1995), 35 C.P.C. (3d) 230, 101 Man. R. (2d) 316 (Q.B.).

[84] The present case is distinguishable. The respondents did not put forward a different case at trial. Dr. Asher testified, both on discovery and on cross-examination, that there were approximately 300 c.c. of amniotic fluid. The respondents led evidence at trial that indicated 300 c.c. of amniotic fluid did not constitute oligohydramnios for a pregnancy of 42 weeks. Dr. Asher's original discovery answer, that he thought the "child showed oligohydramnios at birth", even if not corrected or explained, did not require the trial judge to find that there was oligohydramnios. There was ample evidence before the trial judge for him to find, as he did, that there was no oligohydramnios at birth.

[85] Accordingly, we do not accept the argument that the appellants were prejudiced by this ruling. The discovery answer did not amount to a formal admission. Even if the trial judge had not allowed Dr. Asher to correct his discovery answers, Dr. Asher was still entitled to give a different answer at trial and explain the reason for the change in his evidence. The trial judge was entitled to decide which version he accepted. The original discovery answers, the corrected answers, and Dr. Asher's explanations were all before the trial judge. The trial judge was entitled to weigh the differing answers and the explanation in deciding the matter. It is clear from his reasons that he accepted Dr. Asher's explanation and the corrected discovery answer. In our view, it was open to the trial judge to reach this conclusion, and there appears to be no basis to interfere with his ruling on this matter.

2000 CanLII 16946 (ON CA)

[86] We see no error in the manner in which this issue was dealt with by the trial judge.

6. Ruling restricting the cross-examinations of defendants to elicit opinion evidence

[87] The appellants discontinued their action against three respondents -- Nurse Brown-Davidson, Nurse Kroeker and Dr. Awad -- on the condition that they be available at trial for cross-examination. The appellants attempted to lead opinion evidence from these witnesses. On appeal the appellants complained about their inability to lead opinion evidence from Dr. Awad.

[88] The trial judge ruled that the appellants were required to comply with rule 53.03 if they intended to elicit opinion evidence from Dr. Awad. As no rule 53.03 reports had been filed, the appellants were required to seek leave of the court. The trial judge further noted that he was required to give leave unless prejudice would result.

[89] Dr. Awad was the pathologist involved in the treatment of Joel Marchand. The respondents objected to counsel for the appellants leading any opinion evidence from Dr. Awad that was not covered by the reports he had prepared as a treating physician. The trial judge ruled that, unless notice was given or leave was granted, Dr. Awad would not be permitted to give independent opinion evidence concerning the conduct of others, or to express his opinion on the cause of Joel's condition. However, the trial judge stated that there could be no objection to Dr. Awad giving opinion evidence concerning his own reports, provided such evidence was limited to his involvement in the matter.

[90] As the cross-examination proceeded, this ruling was applied to limit the right of the appellants to cross-examine Dr. Awad on his opinion of the nature of the abruption, if any, that had occurred. Before this court, the respondents do not attempt to support this ruling. The respondents conceded before us that as Dr. Awad was a treating physician, this was a permissible line of questioning, and that the trial judge erred

2000 CanLII 16946 (ON CA)

in his ruling on the point. In our view, this error did not result in any significant prejudice to the appellants. The appellants presented their own evidence on the nature of the abruption. The trial judge fully considered the appellants' theory and we are not satisfied that Dr. Awad's evidence would have made any difference.

[91] Appellants' counsel sought to cross-examine Nurse Olson with respect to her opinion about the conduct of other respondents -- Nurse Colebrook and Nurse Want -- regarding the use of a fetal heart monitor on July 11, 1991. The respondents objected, arguing that the questions called for inadmissible opinion evidence, and that the respondent could not be qualified as an expert for the purpose of giving opinion evidence.

[92] The trial judge ruled that appellants' counsel was "not entitled to ask Nurse Olson, a party defendant, her opinion concerning the conduct of other defendants". Accordingly, he restricted appellants' counsel to cross-examining Nurse Olson regarding events on July 5, 1991, when she administered the NST to Mrs. Marchand. The trial judge relied on the proposition that a plaintiff cannot on discovery ask one defendant about the conduct of another defendant, and concluded that "if such questions cannot be asked on an examination for discovery I fail to see how such questions can be asked at trial." He then provided the following rationale for his ruling:

> A defendant takes the witness box to defend his or her actions as set out in the pleadings, not to give opinion evidence on issues between the plaintiff and other respondents. The opinion of Nurse Olson on issues between herself and the plaintiffs is relevant to the pleaded issues. Here Mr. Wunder proposes to ask Nurse Olson her opinion on issues which are not pleaded between herself and the plaintiffs.

[93] There is support for the proposition that on an examination for discovery a party cannot obtain an expert opinion from the opposite party about the conduct of another party to the action: See Wade v. Sisters of Saint Joseph of the

2000 CanLII 16946 (ON CA)

Diocese of London (1976), 2 C.P.C. 37 (Ont. H.C.J.); Christoyiannis (Litigation guardian of) v. Benoit, [1998] O.J. No. 5200 (Gen. Div.). As the scope of examination for discovery is wider than cross-examination, as a matter of logic, the proposition ought to apply equally to cross-examination.

[94] Nurse Olson was not qualified as an expert at trial. Like Dr. Awad, Nurse Olson was called to testify about her own involvement in the case. It is necessary, then, to regard Nurse Olson as a lay witness for the purpose of assessing the trial judge's ruling.

[95] As a general proposition, lay witnesses may not testify as to their opinion. However, in R. v. Graat, [1982] 2 S.C.R. 819 at pp. 835-37, 2 C.C.C. (3d) 365 at pp. 378-79, Dickson J. noted that the "line between 'fact' and 'opinion' is not clear". As such, he found "no reason in principle or in common sense why a lay witness should not be permitted to testify in the form of an opinion if, by doing so, he is able more accurately to express the facts he perceived." He stated at p. 379 C.C.C. [p. 837 S.C.R.] that a lay witness would be permitted to give opinion evidence in the following circumstances:

I accept the following passage from Cross on Evidence as a good statement of the law as to the cases in which non-expert opinion is admissible (at p. 448):

> When, in the words of an American judge, "the facts from which a witness received an impression were too evanescent in their nature to be recollected, or too complicated to be separately and distinctly narrated", a witness may state his opinion or impression. . . .

[96] The rationale for admitting opinion evidence in such circumstances is that "it may be difficult for the witness to narrate his factual observations individually." Thus, witnesses are allowed to state their opinions because they "had an opportunity for personal observation", and "were in a position to give the court real help".

2000 CanLII 16946 (ON CA)

[97] The impugned line of questioning went beyond Nurse Olson's personal involvement in the case. She was asked for her opinion on the conduct of other respondents. Nurse Olson was not being asked to state an opinion in order "more accurately to express the facts [she] perceived". The proposed testimony fell outside of the basis for admissibility set out in Graat, supra, and, in our view, was properly disallowed.

7. Rulings preventing impeachment of witnesses on read-ins

[98] Nurse Colebrook was asked a number of questions on examination for discovery about her ability to reach Mrs. Marchand's cervix during her vaginal examination on admission to hospital. Nurse Colebrook stated that she was unable to reach Mrs. Marchand's cervix because it was posterior. She also stated that Mrs. Marchand was tense. These questions and answers were read in as part of the appellants' case.

[99] On cross-examination, counsel for the appellants suggested that Nurse Colebrook was unable to reach Mrs. Marchand's cervix because Mrs. Marchand was tense and not because her cervix was posterior. Nurse Colebrook testified that while Mrs. Marchand was in fact tense, she could not reach her cervix because it was posterior. Counsel for the respondents objected to this line of questioning on the ground that appellants' counsel was attempting to contradict the answers he had read in from Nurse Colebrook's discovery.

[100] The trial judge acknowledged that rule 31.11(4) entitled appellants' counsel to rebut discovery evidence read into the record, but interpreted the rule to mean "that such contradiction must be through another witness or by other admissible evidence apart from the evidence of the defendant who was examined for discovery." He ruled as follows:

> In my view the evidence read into the record cannot be contradicted by cross-examining the author of the statement that was read into the record in an attempt to discredit the very evidence which [counsel] made part of the plaintiff's case.

2000 CanLII 16946 (ON CA)

[101] Rule 31.11 governs the use of examination for discovery at trial. The relevant portions of rule 31.11 provide as follows:

> 31.11 (1) At the trial of an action, a party may read into evidence as part of the party's own case against an adverse party any part of the evidence given on the examination for discovery of,
>
> (a) the adverse party; or
>
> (b) a person examined for discovery on behalf or in place of, or in addition to the adverse party, unless the trial judge orders otherwise,
>
> if the evidence is otherwise admissible, whether the party or person has already given evidence or not.
>
> . . . . .
>
> (4) A party who reads into evidence as part of the party's own case evidence given on an examination for discovery of an adverse party, or a person examined for discovery on behalf or in place of or in addition to an adverse party, may rebut that evidence by introducing any other admissible evidence.

[102] It is clear from the wording of rule 31.11 that a party may read any part of an adverse party's examination for discovery into evidence as part of his or her own case. Moreover, it is also clear that that party is entitled to rebut that evidence by introducing any other admissible evidence. In their discussion of the predecessor to rule 31.11, Holmested and Gale, Ontario Judicature Act and Rules of Practice (Scarborough: Carswell, 1983) at p. 1767, affirm this last proposition:

> If a party, as part of his own case, puts in evidence unfavourable to him from the discovery of the opposite party and does not contradict it, he may be bound by it, but he may contradict that which is unfavourable by other evidence and in the circumstances of the particular case may accept or

2000 CanLII 16946 (ON CA)

> reject such portions as he shall see fit, including the evidence given on discovery. . . . There is no general rule that a party putting in discovery is bound by the answers. If a party, as part of his own case, puts in unfavourable evidence from the discovery of an opposite party, he may contradict it by other evidence . . .

[103] There appears to be no case directly deciding whether a party is entitled to contradict discovery answers read into evidence during cross-examination of the declarant. This is hardly surprising as, for obvious tactical reasons, it will be rare for a party to read in an answer and then seek to impeach the declarant on that very answer.

[104] The wording of rule 31.11(4) does not limit a party's right to rebut discovery answers. Rule 31.11(4) states that a party "may rebut that evidence by introducing any other admissible evidence" [emphasis added]. The words "that evidence" refer to the discovery answers read into evidence. In our view, the words "any other admissible evidence" must refer to any evidence other than the discovery answers read into evidence. We can see no reason in principle to prevent a party from attempting to contradict an adverse party's discovery answers by cross-examining the adverse party.

[105] In our view, the trial judge erred in ruling that appellants' counsel could not attempt to contradict Nurse Colebrook's discovery answers by cross-examining her on those answers. However, it is also our view that no prejudice flowed from the trial judge's erroneous ruling. Counsel objected only after the question was asked and Nurse Colebrook reiterated what she had said on discovery. It is highly unlikely that further cross-examination would have elicited evidence helpful to the appellants.

[106] The real source of prejudice, if any, to the appellants was the tactical decision to read in the answers that Nurse Colebrook gave on discovery. Having read those answers in, the appellants risked that a finding would be made unless they could contradict those answers by other evidence. It was unlikely, as a practical matter, that those answers could have

2000 CanLII 16946 (ON CA)

been effectively contradicted by cross-examining the declarant. Justice Gordon's comment in Collins v. Belgian Dry Cleaners, Dyers and Furriers Ltd., [1952] 1 D.L.R. 712, 4 W.W.R. (N.S.) 241 at p. 244 (Sask. C.A.) is apposite:

> It is perfectly true that . . . a party has been permitted to adduce evidence contradicting parts of the examination for discovery of his opponent put in at the trial. I still cannot understand why counsel still persist in tendering in evidence questions and answers from their opponent's examination for discovery which are diametrically opposed to their client's contention.

8. Ruling prohibiting demonstrative evidence

[107] In the course of his examination in-chief of Dr. Fields, appellants' counsel sought to refer the witness to an enlargement of the test strip produced by the NST administered on July 5, 1990. Counsel for Dr. Asher objected to its use on the grounds that (a) the enlargement was of poor quality and omitted essential details, and (b) the observations that Dr. Fields might make about the enlargement would likely differ from the observations the defendant nurses could make about the originals. Counsel for the nurses and the hospital endorsed those objections, and made the further objection that (c) Dr. Fields was precluded from testifying about the NST strip by the trial judge's ruling limiting Dr. Fields' testimony.

[108] The trial judge ruled that Dr. Fields could comment on the original NST strip, or a copy the same size as the original, but that he could not comment on the enlargement. The rationale for the ruling was that the respondent nurses did not have the enlargement, and that it would not assist the court if Dr. Fields were able to observe something on the enlargement not observable from the original.

[109] It is well established that a decision whether to admit demonstrative evidence is within the discretion of the trial judge: see Draper v. Jacklyn, [1970] S.C.R. 92, 9 D.L.R. (3d) 264 and Shipman v. Antoniadis (1975), 8 O.R. (2d) 449, 58 D.L.R. (3d) 321 (C.A.). We see no basis for interfering with

2000 CanLII 16946 (ON CA)

the trial judge's ruling.

[110] In any event, the ruling could not have affected the outcome of the trial. The original NST strip was already before the court. Dr. Fields was permitted to comment on the original NST strip and the appellants were not prevented from adducing evidence on the matter. This was not a case where a party sought to enter demonstrative evidence to assist a jury in their fact-finding function. The trial was being heard by judge alone, and the trial judge had a copy of the NST strip before him.

9. Ruling permitting cross-examination of Mrs. Kwolek

[111] Mrs. Kwolek, a registered nurse, was called by counsel for the respondent nurses and the hospital as an expert witness. The appellants objected to counsel for Dr. Asher cross-examining witnesses called by counsel for the other respondents on the ground that there was a similarity of interest between the respondent nurses, the hospital, and Dr. Asher.

[112] The trial judge ruled that counsel for Dr. Asher had the right to cross-examine Mrs. Kwolek. He stated that paras. 14 and 27 of the statement of claim were a complete answer to the objection, as the statement of claim pleaded that the medical respondents -- i.e., Dr. Asher -- were responsible for the conduct of the nurses.

[113] The right to confront and interrogate an adverse witness is regarded as a fundamental right of parties to a trial. However, in certain circumstances a party will not be permitted to put leading questions in cross-examination to a witness called by an adverse party. The Law of Evidence sets out these circumstances at p. 940:

> . . . In cases where there are co-defendants with similar interests who have pleaded separately and are represented by different counsel, a trial judge has a discretion to refuse to allow counsel for one defendant to cross-examine a co-defendant's witnesses. If, however, the interests of the

2000 CanLII 16946 (ON CA)

parties are not similar, separate counsel are usually allowed to cross-examine a co-defendant or that co-defendant's witnesses.

[114] It is necessary, then, to determine whether the respondent nurses were adverse in interest to Dr. Asher.

[115] The statement of claim pleads that the respondent doctors were responsible for the conduct of the nurses. The doctors would undoubtedly seek to establish that they were not negligent; rather, any negligence was the sole responsibility of the nurses. The nurses would undoubtedly seek to establish that they were not negligent and that any negligence was the sole responsibility of the doctors. Accordingly, based upon the appellants' statement of claim, the respondent nurses and Dr. Asher were adverse in interest.

[116] In their statement of defence, the nurses denied that the doctors were responsible for their conduct, and denied that they were negligent. The nurses stated that they had no knowledge of the negligence alleged to have been committed by the doctors. The hospital and nurses crossclaimed against the medical respondents, and relied upon the allegations contained in the appellants' statement of claim. Similarly, the medical respondents, in their statement of defence, denied all allegations contained in the statement of claim, and crossclaimed against the hospital and nurses.

[117] In view of the pleadings, the trial judge properly concluded that there was an adversity of interest and he properly allowed counsel for Dr. Asher to cross-examine Nurse Kwolek.

B. Uneven Application of Evidentiary Rulings

[118] The appellants submit that the uneven application of certain evidentiary rulings provides further indication of bias on the part of the trial judge.

1. Ruling relating to Dr. Tithecott

2000 CanLII 16946 (ON CA)

[119] The respondents called Dr. Tithecott, a treating physician, as a witness. Dr. Tithecott was asked questions regarding the cord gases, and the inferences he drew from them for the purpose of resuscitating Joel Marchand. He was also asked about the significance of the "marked metabolic acidosis" that Joel Marchand's cord gases displayed. Dr. Tithecott testified that the acidosis "indicated to me that the child had suffered a severe event a short time before delivery". Counsel for the appellants objected on the grounds that (a) Dr. Tithecott was being asked to give opinion evidence, (b) no notice of that opinion had been given to the appellants, (c) counsel for the respondents was obliged to comply with rule 53.03, and (d) Dr. Tithecott ought to be confined to the "four corners of his report". Appellants' counsel was particularly concerned about Dr. Tithecott giving evidence about the timing of the severe event.

[120] The trial judge allowed the examination to proceed. The appellants contend that this ruling is inconsistent with the Awad ruling. Like Dr. Awad, Dr. Tithecott was not a "rule 53.03 witness". Dr. Tithecott was called as a witness of fact, not as an expert witness. Thus, insofar as Dr. Tithecott was testifying about the facts of his own involvement, or the opinions that went to the exercise of his judgment, rule 53.03 was not engaged. We have found that the trial judge erred in applying rule 53.03 to limit the cross-examination of Dr. Awad. However, it is our view that a number of factors distinguish the situation with respect to Dr. Tithecott sufficiently to explain any difference in the manner the trial judge dealt with his evidence. The appellants had substantial notice of this area of questioning by way of: Dr. Tithecott's examinations for discovery, his responses to requests to admit, and the report that he made contemporaneously with his examination of Joel Marchand. Another distinguishing point i s that the trial judge took into account the appellants' right of reply in assessing whether there was any prejudice. In our view, there is no merit to the submission that the trial judge's ruling on this issue indicates bias or an unwillingness to apply the same standard to the respondents as he had applied to the appellants.

2. Rulings relating to Dr. Smith

2000 CanLII 16946 (ON CA)

[121] The appellants complain of two rulings with respect to Dr. Smith. Dr. Smith prepared three reports. The first ruling concerned his third report, filed by the respondents 10 months before Dr. Smith testified, and some four months after Dr. Manning had testified. The report dealt with different blood gas orders. The trial judge ruled that Dr. Smith could testify about his third report. The second ruling permitted counsel for Dr. Asher to ask Dr. Smith to comment on testimony given by Dr. Whyte in cross-examination. The first ruling is said to be inconsistent with the Silver ruling and the second with the Fields ruling.

[122] In our view, there is no merit to these submissions. The trial judge distinguished the Silver ruling on several grounds. It became apparent that appellants' counsel was aware that there were two different blood gas orders and could have raised the matter with Dr. Manning. Accordingly, the trial judge ruled that he was not taken by surprise and that Dr. Smith could give evidence about the contents of the third report. The trial judge also differentiated the Silver ruling from the present situation, noting that Dr. Smith's third report was delivered 10 months before the defence started. Moreover, even if something new was raised by the defence it could be addressed through the appellants' right of reply.

[123] The second ruling concerning Dr. Smith was also correct. It is well established that an expert witness can be asked to comment on the opinion of another expert: see Quantrill v. Alcan-Colony Contracting Co. (1978), 18 O.R. (2d) 333 (C.A.).

3. Ruling relating to Dr. Eyman

[124] Dr. Eyman was called by the respondent, Dr. Asher, to give expert evidence on the issue of Joel Marchand's life expectancy. Dr. Eyman had prepared two reports on the issue of damages. The first report was dated November 12, 1993 and was prepared on the basis of materials sent to Dr. Eyman by the respondents. The second report was dated May 5, 1994 and was prepared after Dr. Eyman attended a physical examination of

2000 CanLII 16946 (ON CA)

Joel Marchand conducted by two other physicians, and viewed four hours of videotapes of Joel Marchand. The second report was based upon Dr. Eyman's own observations and the observations of the two other physicians.

[125] During the voir dire on the foundational facts issue, Dr. Eyman was asked what materials he was sent and what materials he relied upon. He could not recall precisely what materials he relied upon. The appellants submitted that, in accordance with the foundational facts ruling, the respondents were required to prove all the documents Dr. Eyman had been given. The trial judge rejected this argument.

[126] The trial judge differentiated his ruling with respect to Dr. Eyman from his rulings with respect to Ms. Kelly and Ms. Staub. He characterized his rulings with respect to Ms. Kelly and Ms. Staub as a response to the appellants' attempts to rely upon a different set of facts from those relied upon by Ms. Kelly and Ms. Staub. In contrast, his ruling with respect to Dr. Eyman was based on the respondents having proven the same set of facts relied upon by Dr. Eyman, albeit through different means.

[127] Dr. Eyman's reports appeared to be based on factual observations; for example, whether Joel Marchand could crawl. Observations of this nature would be capable of proof through various sources. It appears to us that in the Eyman ruling, the trial judge characterized the appellants' position concerning Ms. Kelly's and Ms. Staub's reports as an attempt to rely upon "X, Y, Z" rather than "A, B, C" where the experts had relied upon "A, B, C" in preparing their reports. We have already found that to the extent the trial judge limited the right of the appellants to establish the same foundational facts relied on by Ms. Kelly and Ms. Staub through different means, he erred. However, as the Eyman ruling indicates, the trial judge was endeavouring to be consistent. If he erred in the application of the Kelly and Staub rulings, any error he committed falls well short of an indication of bias or a predisposition to favour the respondents.

C. Conclusion on the Evidentiary Rulings

2000 CanLII 16946 (ON CA)

[128] We conclude that the evidentiary rulings of the trial judge and the manner in which they were applied do not support the contention that the appellants were denied the opportunity to fairly present their case, nor did these rulings create a reasonable apprehension of bias on the part of the trial judge. The trial judge's rulings were carefully considered and reflect, in our view, a sincere and diligent effort to conduct a fair trial. We have concluded that virtually all of the impugned rulings were correctly decided. The very few errors we have identified were inconsequential and even viewed cumulatively did not result in any significant prejudice to the appellants. Accordingly, this ground of appeal is dismissed.

III. DID THE TRIAL JUDGE'S CONDUCT OF THE TRIAL RAISE A REASONABLE APPREHENSION OF BIAS?

[129] The appellants' main contention on the appeal is that the trial judge's conduct of the trial raised a reasonable apprehension of bias towards them. They submit that throughout the trial defence counsel were insulting, hostile, discourteous and rude to their counsel, Mr. Wunder, and indeed to Mrs. Marchand, and yet the trial judge condoned this behaviour, never restraining or controlling it. The appellants submit that, by itself, the trial judge's refusal to restrain defence counsel raises a reasonable apprehension of bias. The appellants also submit that the trial judge showed hostility to Mr. Wunder, that he interfered in Mr. and Mrs. Marchand's presentation of the case, and that, in his reasons, he unfairly judged the credibility of Mrs. Marchand. All of this conduct, the appellants contend, further supports their claim of judicial bias.

[130] The trial judge's conduct, which the appellants submit cumulatively amounts to judicial bias, can conveniently be discussed under the following six categories, of which the first is by far the most serious:

(1) the trial judge refused to restrain defence counsel's repeated attacks on Mr. Wunder's integrity and competence;

2000 CanLII 16946 (ON CA)

(2) the trial judge refused to control defence counsel's inappropriate treatment of Mrs. Marchand;

(3) the trial judge prevented the appellants from fairly presenting their case by his one-sided interventions;

(4) the trial judge on one occasion talked with defence counsel in the absence of appellants' counsel;

(5) the trial judge unfairly criticized Mr. Wunder; and

(6) the trial judge showed antipathy to Mrs. Marchand in his reasons for judgment.

[131] Before considering this ground of appeal, we will briefly review the principles that apply to a claim of judicial bias. These principles, now well established, have recently been summarized by the Supreme Court of Canada in R. v. S. (R.D.), [1997] 3 S.C.R. 484, 118 C.C.C. (3d) 353. They are as follows:

1. All adjudicative tribunals owe a duty of fairness to the parties who appear before them. The scope of the duty and the rigour with which the duty is applied vary with the nature of the tribunal. Courts, however, should be held to the highest standards of impartiality.

2. Impartiality reflects a state of mind in which the judge is disinterested in the outcome and is open to persuasion by the evidence and submissions. In contrast, bias reflects a state of mind that is closed or predisposed to a particular result on material issues.

3. "Fairness and impartiality must be both subjectively present and objectively demonstrated to the informed and reasonable observer. If the words or actions of the presiding judge give rise to a reasonable apprehension of bias to the informed and reasonable observer, this will render the trial unfair." (at p. 524 S.C.R.)

4. The test for bias contains a twofold objective standard: the

2000 CanLII 16946 (ON CA)

person considering the alleged bias must be reasonable and informed; and the apprehension of bias must itself be reasonable. In the words of de Grandpr J. in Committee for Justice and Liberty v. Canada (National Energy Board), [1978] 1 S.C.R. 369 at p. 394, 68 D.L.R. (3d) 716, approved of by the Supreme Court of Canada in S. (R.D.), supra:

[T]he apprehension of bias must be a reasonable one, held by reasonable and right-minded persons, applying themselves to the question and obtaining thereon the required information. . . . [The] test is "what would an informed person, viewing the matter realistically and practically -- and having thought the matter through -- conclude. . . ."

5. The party alleging bias has the onus of proving it on the balance of probabilities.

6. Prejudgment of the merits, prejudgment of credibility, excessive and one-sided interventions with counsel or in the examination of witnesses and the reasons themselves may show bias. The court must decide whether the relevant considerations taken together give rise to a reasonable apprehension of bias.

7. The threshold for a finding of actual or apprehended bias is high. Courts presume that judges will carry out their oath of office. Thus, to make out an allegation of judicial bias requires cogent evidence. Suspicion is not enough. The threshold is high because a finding of bias calls into question not just the personal integrity of the judge but the integrity of the entire administration of justice.

8. Nonetheless, if the judge's words or conduct give rise to a reasonable apprehension of bias, it colours the entire trial and cannot be cured by the correctness of the subsequent decision. Therefore, on appeal, a finding of actual or apprehended bias will ordinarily result in a new trial.

[132] The respondents deny that either the words or the

2000 CanLII 16946 (ON CA)

conduct of the trial judge gave rise to a reasonable apprehension of bias. They submit, in the alternative, that the appellants waived their right to claim judicial bias and should be precluded from doing so on appeal. In support of their submission on waiver, they say that an allegation of bias should be raised at the first available opportunity, and that instead the appellants waited until 19 months after the completion of the evidence and three months after the release of the reasons for judgment. They also point out that the appellants opposed four mistrial motions brought by the defence during the trial and that the appellants insisted the trial judge hear their own motion for a mistrial (because of the alleged perjury of a witness) even while their motion to recuse the trial judge for bias was pending. [See Note 2 at end of document] It is unnecessary for us to consider this alternative submission of waiver in the light of our conclusion that the appellants' claim of judicial bias fails on its merits.

[133] We therefore turn to the appellants' allegation of judicial bias, applying the legal principles we summarized to the six categories of bias raised by the appellants.

1. The Trial Judge Refused to Restrain Defence Counsel's Repeated Attacks on Mr. Wunder's Integrity and Competence

[134] This is the appellants' main submission in support of their allegation of judicial bias. They submit that throughout the 165 days of trial, defence counsel repeatedly accused their counsel, Mr. Wunder, of manipulating evidence; of deliberately misinforming witnesses and feeding them answers through objections during cross-examination; of deliberately flouting, subverting and ignoring the rules of practice; and of showing contempt for the trial judge and his rulings. They contend that the trial judge failed to restrain defence counsel's repeated attacks on Mr. Wunder's integrity and competence, and by not restraining it, the trial judge condoned it and lent the weight of his office to the defence position. Thus, the appellants argue that the trial judge's failure to restrain defence counsel's attacks on Mr. Wunder gave rise to apprehended bias.

[135] The record shows that from early on in the trial, any

2000 CanLII 16946 (ON CA)

degree of trust between Mr. Wunder, on the one hand, and Mr. Tait, counsel for Dr. Asher, and Mr. Liswood, counsel for the hospital and nurses, on the other, had completely vanished, to be replaced by a level of rancour and hostility rarely, if ever, seen in an Ontario courtroom. The record also amply supports the appellants' contention that Mr. Tait repeatedly attacked Mr. Wunder's integrity and competence. Comments about counsel that have no place in any courtroom infected this trial from start to finish. The following examples should adequately give the flavour of what took place.

[136] Mr. Tait accused Mr. Wunder of "a complete lack of integrity"; of cheating and intentionally defying the rules of practice; of using the right to object to cross-examination "to suggest answers to every witness who has come into this courtroom"; of abuses of the Rules of Civil Procedure; of using and abusing solicitor-client privilege as a "mask for deception", to "conceal misconduct", "as a manipulative device", "to conceal the devices by which the evidence of witnesses is manipulated" and as a "shield for deceit"; of "manipulating" the evidence and facts; of deliberately misinforming an expert witness; of "flatly lying" to the court; of deliberately misleading the court, showing contempt for the court, defying and deceiving the court about the evidence of Dr. Whyte; of "trickery" and "sleight of hand"; and of committing an outrage on the court. Mr. Tait told the trial judge that he (Mr. Tait) [was] wrong to assume Mr. Wunder was competent and would comply with the Rules of Civil Procedure, and he ev en suggested that Mrs. Marchand made a mistake in choosing Mr. Wunder as her counsel.

[137] The following two passages typify the tenor of Mr. Tait's verbal attacks on Mr. Wunder:

> I don't want to leave today . . . without at least indicating to Your Honour, the sense of total outrage, that a deceitful, legal mind could possibly invent so preposterous a distortion of the judicial process; a complete violation of every principle of Ashmore that he has so freely adopted.

. . . . .

2000 CanLII 16946 (ON CA)

> This is a profound disgrace. I invite Your Honour to reread Ashmore tonight and I invite you to tell Mr. Wunder to take this argument to the Court of Appeal if he wishes, but it will not be heard in this court.
>
> . . . . .
>
> It wasn't for me to say that I disagreed with the ruling. We accept it and we went on. But to come forward with this kind of scurrilous manipulation, of which -- of what, for Mr. Wunder was essentially a break, a break that he so genuinely didn't expect that he invited you to rule last week.
>
> . . . This is scurrilous and this is disgraceful and I ask Your Honour not to countenance it.
>
> . . . . .
>
> Mr. Wunder has abused the rules of practice and his obligations as counsel in respect of this particular witness at every turn. And the rules of practice and the relief they provide for honest counsel are not there as an excuse to permit unchecked grossly improper manipulation of the whole litigation process.

[138] Mr. Tait was not alone in his criticisms of Mr. Wunder. Mr. Liswood, too, maligned the appellants' counsel. He accused Mr. Wunder of manipulating, abusing and making a mockery of the judicial system; of using the Rules of Civil Procedure as an "excuse to permit unchecked grossly improper manipulation of the whole litigation process"; of "flagrantly subverting" the Rules of Civil Procedure; of "suppressing" facts and information from the defence; of "contrivance and manipulation" in the delivery of expert reports; of continually withdrawing from his commitments; and of violating Rule 10 of the Rules of Professional Conduct by knowingly attempting to deceive the court and by knowingly misstating the contents of documents.

[139] We do not intend to suggest that this conduct was all one-sided. On occasion, Mr. Wunder acted in a similar way. But

2000 CanLII 16946 (ON CA)

Mr. Tait and Mr. Liswood must accept most of the responsibility for conduct that by any reasonable standards of civility was unacceptable for any counsel, let alone senior counsel who should know better.

[140] In this court, Mr. Ortved and Mr. Curry, who acted for Dr. Asher, made no attempt to defend Mr. Tait's conduct or to substantiate any of Mr. Tait's many allegations against Mr. Wunder. Instead, they candidly acknowledged that Mr. Tait's conduct toward Mr. Wunder had fallen below an acceptable standard. Mr. Liswood also acknowledged that his own conduct at trial had been unacceptable. We have little doubt that the appellants must have found the repeated maligning of their counsel unsettling, to say the least.

[141] The unprofessional conduct of counsel is a matter for the Law Society of Upper Canada. The issue before us, however, centres not on the conduct of counsel but its impact on the fairness of the trial. Our focus centres on the conduct of the trial judge. The question we must answer is whether an informed person viewing the matter realistically would conclude that the way the trial judge dealt with defence counsel's attacks on Mr. Wunder created a reasonable apprehension of bias and thus deprived the appellants of a fair trial. We are not persuaded that the trial judge's conduct supports a finding of bias.

[142] There are three answers to the appellants' submission that a reasonable apprehension of bias arises from the trial judge's refusal to restrain or control defence counsel. First, the trial judge did not remain silent about counsel's conduct. He intervened in the trial. On the fifteenth day of the trial, November 16, 1993, Mr. Tait accused Mr. Wunder of manipulating the schedule of witnesses to give one of the appellants' experts, Dr. Fields, time to repair his evidence. Mr. Wunder objected to this characterization of his conduct. The trial judge responded:

> Look, he says a lot of things and you say a lot of things. I do not pay a whole lot of attention to what you are saying on those matters. Now, let us just proceed with this.

2000 CanLII 16946 (ON CA)

[143] The following day, Mr. Tait protested that in his 27 years of practice he had "never been so badly treated by any other counsel". He added that he had "never met the equal of Mr. Wunder for ignoring his obligations". This time, the trial judge replied at length, in an attempt to change the atmosphere of the trial. He urged counsel to stop their "interminable fighting" and he emphasized the need for civility in the courtroom:

> Let me say this that it struck me last night as I reflected upon what I considered to be a rather lengthy day. We had some rather strenuous debates about certain matters that we should never lose sight of why we are here. It strikes me that what we are here to do is to try this issue fairly, make sure we try it fairly to all parties, and to achieve that there has to be full and complete disclosure. Having practiced in those days when you did not make disclosure unless you had to, I know what it is like. But those are not what we are doing today. These cases are far too complex for that.
>
> I am also struck, as I read in the latest issue of the Canadian Lawyer, somebody was interviewing the former Attorney General, Ian Scott, and he said that the only thing that makes litigation is good manners. Somehow there's a lack of manners in this trial and I do not suggest to point a finger at anyone. I think it is important, we are going to be here for another few weeks. We are into our fifth week and there is no reason why we cannot all act like gentlemen in the courtroom. We can stop sniping at each other. If anybody thinks that there has been prejudice as a result of a lack of disclosure, they can politely argue strenuously, but politely argue rule 53.08 and 31.07, all deal with the matter. If anybody thinks that as a result of the lack of disclosure that they have been prejudiced and they want an adjournment, I am going to grant it. I make it abundantly clear right now that I am going to do my utmost to make sure that this matter is fairly dealt with. We have a plaintiff here who is entit led to have her action heard before this court. She wants to have it heard whether she is right or wrong. We will not know until the case, but she will have heard, and so will Dr.

2000 CanLII 16946 (ON CA)

Asher and so will the nurses. They are entitled to that. So I just urge you all, let us get along. Let us try and move along with this case. It is going to be long enough without this interminable fighting.

. . . . .

Let us move on but let us not conduct ourselves in a manner in which it really does not place the legal profession in a good light. We have a tough enough issue as it is to try now. Let us move forward.

[144] Unfortunately, the trial judge's exemplary words seemed to have had little effect. Soon after, Mr. Tait again disparaged Mr. Wunder's ability:

. . . Mr. Wunder is a counsel who lectures the profession and writes books about trial preparation. He's a senior counsel. He's entitled to style himself a Queen's Counsel and while I have a dim view as to his appreciation of the contents of the Rules of Practice, that is no excuse for adjourning a trial.

[145] The appellants complain that though the trial judge's intervention on November 17, 1993 was salutary, after that day and indeed for the rest of the trial, the trial judge never tried to restrain defence counsel. This complaint is not entirely correct because on February 9, 1994, during an interchange with Mr. Percival (acting for Mr. Wunder on a motion), the trial judge again commented on counsel's conduct:

Mr. Percival: I am sorry, I wish I could be more helpful to you on that issue, but as I said, I felt that that was the address because I saw, I thought to a certain extent there was some very, I thought, intemperate and rather strong language utilized by Mr. Liswood, condemning the conduct of Mr. . . .

The Court: There has been a lot of strong language in this trial . . .

Mr. Percival: Well, I'm not going to try to get into it.

2000 CanLII 16946 (ON CA)

The Court: . . . Mr. Percival on both sides, and I keep reminding counsel of what the former Attorney General said, that only good manners makes litigation bearable.

Mr. Percival: I understand.

The Court: And that falls on deaf ears from time to time in this trial.

Mr. Percival: And I know that this has been a very difficult trial. I've seen some of the transcripts. I certainly have not had the opportunity to do it all, and as I said to you before, this has been a very difficult case I think for everybody, quite apart from your Honour.

[146] Although the appellants say that the trial judge should have done more, his observations both in November 1993 and in February 1994 at least show that he was not oblivious to what was taking place and that he tried to control counsel's conduct.

[147] Second, the failure of the trial judge to do more to restrain or control defence counsel does not automatically indicate judicial bias. We recognize that other trial judges might well have dealt with the acrimony in the courtroom differently, and perhaps more effectively. This trial judge chose to be relatively passive, indeed, probably too passive. He was well aware of the acrimony and chose largely to ignore [it].

[148] Just as civility in the courtroom is very much the responsibility of counsel, it is also very much the responsibility of the trial judge. It is [a] shared responsibility of profound importance to the administration of justice and its standing in the eyes of the public it serves. Unfortunately, we have no doubt that the failure to satisfactorily discharge this responsibility in this case tarnished the reputation of the administration of justice. This case underlines the importance being given by leaders of the bench and bar to improving civility in the courtroom.

2000 CanLII 16946 (ON CA)

[149] However for this court, the question must be whether in light of what went on in the courtroom there was a reasonable apprehension of bias on the part of the trial judge, thus depriving the appellants of a fair trial. Nothing in the trial record or in the trial judge's reasons suggests that he condoned defence counsel's conduct or lent the weight of his office to the defence position. A review of the transcripts establishes that counsel's conduct had no effect on the trial judge's efforts to fairly judge the case before him. The trial judge's reasons are thorough and present a fair and balanced consideration of all the contentious issues in the trial. In short, we do not think that an informed and reasonable observer looking realistically at the trial unfolding would apprehend from the trial judge's conduct that he was biased, or unfair in adjudicating this case.

[150] Third, and admittedly a less important answer to the appellants' submission, is that most of the acrimonious language and most of the attacks on Mr. Wunder occurred during submissions on motions, not during the presentation of evidence. This, in our view, is one reason why defence counsel's conduct had no impact on the appellants' fair presentation of their case.

[151] To conclude this ground of appeal, although we deplore the conduct of defence counsel, the appellants have not shown that the way the trial judge dealt with defence counsel's attacks on Mr. Wunder gave rise to a reasonable apprehension of bias.

2. The Trial Judge Refused to Control Defence Counsel's Inappropriate Treatment of Mrs. Marchand

[152] The appellants submit that defence counsel's conduct towards Mrs. Marchand was inappropriate and went unchecked by the trial judge. The appellants rely on five examples of inappropriate conduct. The first two examples show defence counsel in an unflattering light. However, none of the examples suggest judicial bias. We will deal briefly with each of them:

2000 CanLII 16946 (ON CA)

(a) During Mrs. Marchand's first day of testimony, Mr. Tait commented to Mr. Liswood, "She's a liar." This unfortunate comment was said loud enough for Mrs. Marchand to hear it and loud enough for the court reporter to record it. However, the trial judge did not hear the comment and, once apprised of it, he neither condoned nor accepted it.

(b) The appellants submit that Mr. Tait and Mr. Liswood taunted Mrs. Marchand with deprecating facial expressions from the counsel table. The record suggests that defence counsel rolled their eyes, smiled and laughed out loud during parts of Mrs. Marchand's cross-examination. Defence counsel's conduct again was unprofessional but, in our view, did not affect the fairness of the trial.

(c) The appellants contend that Mr. Tait taunted Mr. and Mrs. Marchand by gratuitously reminding them again and again that their son Joel had almost no brain tissue. We find no merit in this contention. Throughout the trial, Mr. Tait accepted that Joel Marchand had suffered a tragic injury. In our view, neither the phrasing nor the tone nor the content of his cross-examination of Mr. and Mrs. Marchand was objectionable. The issues in the case required the defence to explore Joel's brain function, his ability to see and whether he could play with a computer. As the trial judge pointed out to Mrs. Marchand, questioning on these issues was relevant to Joel's life expectancy and to the appellants' damages claim. The absence of any objection to this questioning from the appellants' counsel is perhaps the best evidence that the cross-examination was not unfair.

(d) The appellants also submit that on cross-examination defence counsel harassed Mrs. Marchand for being unable to remember her last menstrual period in September 1989. The defence undoubtedly conducted a tough, aggressive cross-examination but, in our view, not a harassing cross-examination. Joel's expected due date and its relationship to Mrs. Marchand's menstrual period was an important issue at trial, and Mrs. Marchand had previously given five different answers about when her last menstrual

2000 CanLII 16946 (ON CA)

period occurred. Again, Mr. Wunder did not object either to the tone or to the length of the cross-examination on this issue. In a trial where both sides made frequent objections and interjections, the lack of an objection on this issue is a good indicator that this complaint now made has little substance.

(e) Finally, the appellants submit that defence counsel insulted and belittled Mrs. Marchand during their cross-examination of her. As we have said, the cross-examination was at times aggressive, apparently even loud. But we do not consider it to have been unfair. Mr. Wunder did at one point ask the trial judge to ask Mr. Tait to "keep his tone down and not be rude to the witness". The trial judge refused, commenting that he did not think Mr. Tait had been rude but that if Mrs. Marchand was being intimidated he would intervene. In the light of this observation and our review of the entire cross-examination of Mrs. Marchand, we cannot find anything in the words or the conduct of the trial judge that would reasonably suggest that he was biased.

3. The Trial Judge Prevented the Appellants from Fairly Presenting Their Case by His One-Sided Interventions

[153] The appellants submit that the trial judge intervened excessively during Mr. Wunder's cross-examination of witnesses and by doing so, prevented the appellants from fairly presenting their case. Before discussing the interventions the appellants rely on, we will briefly review the legal principles that apply to this submission.

[154] A trial judge is not required to sit mute and listen to evidence without commenting or interjecting. A trial judge has the right, indeed the duty, to intervene to clarify and understand the evidence or to control the trial, provided that in intervening, the trial judge does not interfere with the fair presentation of the evidence and does not prejudge the issues in dispute or the credibility of the witnesses. The limits on the trial judge's right to intervene were concisely set out by Evans J.A. in Majcenic v. Natale, [1968] 1 O.R. 189

2000 CanLII 16946 (ON CA)

at p. 203, 66 D.L.R. (2d) 50 (C.A.):

> . . . I can appreciate that on occasion it is not only desirable but necessary that the trial Judge question the witnesses for the purpose of clarification of the evidence and I do not consider that he is solely an umpire or arbitrator in the proceedings. There is a limit however to the intervention and when the intervention is of such a nature that it impels one to conclude that the trial Judge is directing examination or cross-examination in such a manner as to constitute possible injustice to either party, then such intervention becomes interference and is improper.

[155] The appellants submit that the trial judge in this case crossed the permissible limits of intervention. We disagree. The appellants gave several examples of what they claimed were one-sided interventions by the trial judge during Mr. Wunder's cross-examination. These examples were put forward to show that the trial judge unfairly intervened to articulate a defence position or that he disrupted the appellants' presentation to a degree that raised a reasonable apprehension of bias. We will review the most salient examples, most of which were not objected to at the time and none of which, in our view, supports the appellants' submissions.

[156] The appellants point to an intervention by the trial judge during the cross-examination of Dr. Asher. Mr. Wunder was trying to impeach Dr. Asher on his discovery evidence, and defence counsel objected that Mr. Wunder had not done so properly. The trial judge intervened, appropriately, to point out that Mr. Wunder had not covered the topic on Dr. Asher's discovery:

> The Court: But you did not ask.
>
> Mr. Wunder: I'm sorry, sir?
>
> The Court: You did not ask him, how much did you take out after.
>
> Mr. Wunder: Well . . .

2000 CanLII 16946 (ON CA)

The Court: I think the important point is, Mr. Wunder, you said, "You didn't tell me this on discovery."

Mr. Wunder: Yes, sir.

The Court: And he did tell you about taking them about after and I do not appreciate you suggesting to a witness that "you don't tell me something on discovery" when he does in fact tell you something on discovery.

Mr. Wunder: Your Honour, well -- you are the final arbiter of that, as to whether or not it's . . .

The Court: No, but you were -- you were suggesting to this witness that this evidence about him taking the clots out of the uterus was brand new evidence which you had never heard of before.

[157] Mr. Wunder eventually accepted that he had not adequately dealt with the topic on discovery when he said: "And I guess I can be faulted for not asking you in greater detail the quantity or how it was removed."

[158] The appellants also point to an incident that arose during an argument over the late disclosure of Dr. Kirsch's medical records. Defence counsel suggested an adverse inference might be drawn on a particular point. Mr. Wunder questioned what the adverse inference might be. Instead of allowing defence counsel to answer, the trial judge responded:

The Court: Well, suppose that the adverse inference he proposes to advance is that I find as a fact that Barbra suffered severe pain.

Mr. Wunder: If that is my friend's position, if you articulate it adequately I would like to hear it from him.

Mr. Liswood: Joe, may I . . .

Mr. Wunder: Excuse me, wait, could I have Mr. Colangelo

2000 CanLII 16946 (ON CA)

-- I'd like to know from Mr. Colangelo . . .

The Court: Well, he would extend that I would think. On his argument he would extend it that that would alter the opinions of Dr. Fields, Manning, Johnson. He would say the same thing with regard to the use of the hands and scooting.

Mr. Wunder: I would just like my friend to articulate what adverse inference that he is talking about so that I can meet the argument, sir, and appreciate his argument.

The Court: Well, I am not absolutely sure that he has to because what he is saying is that that is a possibility and he says that I cannot deal with that until we get to the end of the trial.

Mr. Wunder: I understand, sir. He did not complete the sentence. He is going to argue an adverse inference. I would like to know what adverse inference, that's all, from him.

The Court: Well, he is going to argue it at some later date.

[159] In our view, the trial judge did not act improperly in intervening to set out the defence position. This was probably done with a view to moving the trial along. Moreover, counsel for all the parties fully argued whether an adverse inference should have been drawn without any inappropriate intervention by the trial judge.

[160] The appellants also point to an intervention by the trial judge during Mr. Tait's cross-examination of the appellants' expert, Dr. Fields, on his qualifications to give opinion evidence. Mr. Wunder objected to the questioning and the trial judge responded:

Mr. Wunder: Your Honour, aren't all these questions really designed to go to a matter of weight? The doctor is really qualified to give opinion evidence.

The Court: I suspect that I may hear some argument as to the ability of this witness, or whether or not I should allow

2000 CanLII 16946 (ON CA)

this witness to give expert evidence as to the standard of care which might be expected in Ontario if he is not familiar with it. He makes a bald statement. He makes a bald statement as I understand it. I am only anticipating what I think Mr. Tait might say, that he makes a bald statement that the standard of practice is the same.

Mr. Wunder: Well, the . . .

The Court: That is quite a different question than saying that he does not have expertise.

Mr. Wunder: Expertise evidence is expert evidence received by courts without regard to geographical barriers, and often . . .

The Court: Well, let us let Mr. Tait press on and we will come back to you, Mr. Wunder, when we argue this whole issue.

Mr. Wunder: Thank you, sir.

The trial judge's comments are innocuous and no possible apprehension of bias can arise from them, particularly because the trial judge permitted Dr. Fields to give expert evidence.

[161] Finally, the appellants submit that the trial judge especially interfered with their presentation of the case during the cross-examination of Dr. Asher on his withdrawal of the admission of oligohydramnios. A lengthy argument took place during this cross-examination, much of it over an excerpt from a textbook on obstetrics. During the argument, covering 44 pages of transcript, the trial judge intervened many times and put a few questions to the witness. However, as we read these pages, the trial judge was simply trying to control, as he was entitled to do, a heated exchange between counsel. As well, the few questions the trial judge asked were not obviously helpful to the defence.

[162] The appellants cite other examples from Mr. Wunder's cross-examination, which they say also demonstrate that the

2000 CanLII 16946 (ON CA)

trial judge's interventions were one-sided. We do not think that individually or collectively these other examples support the appellants' claim of judicial bias. The trial judge intervened when needed in order to try to control this difficult trial and to understand the evidence, including intervening during defence counsel's cross-examination.

4. The Trial Judge Spoke with Defence Counsel in the Absence of Mr. Wunder

[163] On one occasion in April 1995, respondents' counsel telephoned the trial judge to find out whether he would sit two days previously scheduled as non-sitting days to accommodate an out-of-town witness. Mr. Wunder was not party to the call, apparently because he was ill and was home recovering. The appellants now contend that the trial judge exhibited bias by speaking to respondents' counsel alone.

[164] We see no merit in this contention. The telephone call was limited to scheduling. Moreover, it was disclosed immediately to Mr. Wunder in writing and the next day in open court. Mr. Wunder accepted the trial judge's explanation for the telephone call.

5. The Trial Judge Unfairly Criticized Mr. Wunder

[165] The appellants submit that not only did defence counsel unfairly criticize their counsel, so too did the trial judge. The contend that the trial judge showed "a deeply critical attitude, perhaps outright hostility" toward Mr. Wunder. In our view, the trial record does not substantiate this contention. We will refer briefly to the two examples relied on by the appellants during oral argument to show that their contention has no merit.

[166] The appellants pointed to an exchange between the trial judge and Mr. Wunder over the contents of expert reports, which took place during the examination-in-chief of the appellants' expert, Dr. Geisler. The exchange was as follows:

Mr. Wunder: Your Honour, I cannot believe that my friends'

2000 CanLII 16946 (ON CA)

cross-examination is limited to and dependent upon what is in the plaintiff's reports. I just can't believe it. Surely they bring much more to this trial than that and surely they can't complain that they chose not to cross-examine people on issues that relate clearly to life expectancy.

The Court: Now wait a second. Let me get something straight, Mr. Wunder. If I am defending a case and I have your medical reports which identifies the areas that your experts are going to talk on or give evidence on or render opinions on, why would I venture into areas that could be just a mine field, to discuss with the doctor when I know that your other experts are allowed to give evidence about those matters?

Mr. Wunder: Because under our jurisprudence every expert is allowed to expand on his report.

The Court: Well because you see -- where you and I are parting company is that you want to play by the rule -- sort of the ambush rules as your experts get in the box . . .

Mr. Wunder: I resent that remark, Your Honour.

The Court: Well, you know, that is what it is coming down to.

Mr. Wunder: That's what my friends have persuaded you it's coming down to, sir.

The Court: No, they have not persuaded me of anything, Mr. Wunder. I will make up my own mind.

We see nothing unfairly critical in the trial judge's comments, which indeed reflect our views on the issue being debated.

[167] The appellants also rely on an exchange between the trial judge and Mr. Wunder over the "Colebrook ruling", which took place during the cross-examination of Dr. Asher. The relevant part of what was a rather innocuous exchange is as follows:

The Court: You keep saying burdened with the ruling in

2000 CanLII 16946 (ON CA)

Colebrook. I am satisfied that the ruling, the Colebrook Number Two Ruling is correct. You say burdened with it. I would have thought you would have known that. Maybe you did not know that principle.

Mr. Wunder: I certainly didn't, Your Honour.

The Court: Well, there you go.

Mr. Wunder: If I may continue my representations to Your Honour. Here is a statement by you and by me. One, that I didn't want to be taken to vouch for the truthfulness of what Dr. Asher says and I wanted to be able to challenge his credibility. So that was clearly stated on the record. And secondly, you assuring me that I would be able to cross-examine him on that correction, as you said, almost forever. Now . . .

The Court: And you have got that right.

Mr. Wunder: I'm sorry, Your Honour. When someone has a right to cross-examine, Your Honour, you recall from Sopinka, where they lead the simplest fact, one can cross-examine on all issues and I want -- I want to exercise that right. We've been on that before. Do you need the reference from Sopinka, sir?

The Court: No. I know what Sopinka says.

Mr. Wunder: I'm sure you do, sir.

The Court: But you are talking about having read something into the record, making it part of the plaintiff's case, and then are you entitled to cross-examine the author of that statement that you read into the record to prove that it is not true? You and I seem to part company on that. You seem to think that you can. I have said that you cannot.

Again, we find nothing unfair in the trial judge's observations, and certainly none of his observations reflect any animosity or hostility toward Mr. Wunder.

2000 CanLII 16946 (ON CA)

[168] As we have said before, the trial judge presided over a long and difficult trial, marked by open hostility and lack of trust among counsel, and by frequent interruptions by all counsel to the flow of evidence. The trial judge cannot be criticized, let alone be found guilty of judicial bias, for his occasional mild rebuke to counsel. We add that those occasional rebukes were quite evenly distributed throughout the trial and among all trial counsel. The appellants' claim that the trial judge showed "outright hostility" to Mr. Wunder is not substantiated on this record. In sharp contrast to this claim, the trial judge praised Mr. Wunder's dedication to his clients' case, in a ruling on June 3, 1994 dismissing a defence motion to refer Mr. Wunder's conduct to the Official Guardian for review:

> I assume that Mr. Liswood and Mr. Colangelo are suggesting that Mr. Wunder who acts on behalf of the Litigation Guardian, is not protecting the best interests of Joel Marchand and accordingly his conduct of this action on behalf of Joel Marchand required review by the Official Guardian.
>
> This trial commenced on October 18th, 1993 and I am told that as of this day, the court has been convened approximately 90 days and the Plaintiffs' case is not complete. I am doubtful that the Plaintiffs' case will be completed by the end of June 1994. Mr. Wunder has appeared at trial on all of the days that court has been convened and although I have not agreed with all of his submissions or the manner in which parts of the Plaintiffs' case has been presented, it would be unfair of me prior to hearing all of the evidence to second guess Mr. Wunder on the presentation of the Plaintiffs' case. Mr. Wunder has been a dedicated counsel who has attempted to present his clients' case in a manner which he feels is most favourable to his client. It would be wrong for me at this time in this trial to say that Mr. Wunder has not acted in the best interests of his clients. In my opinion, the actions of Mr. Wunder in this trial indicate that he perceives that his strategy in presenting his clients' case is in the best interests of his clients and at the end of the trial when I have heard all of the evidence, he may be right.

2000 CanLII 16946 (ON CA)

> Mr. Wunder enjoys an exceedingly high reputation in the person injury field in Ontario and I must take his reputation of excellence into account when I consider the Motion of the Respondents to have this matter referred to the Official Guardian for review. There is absolutely no doubt in my mind that Mr. Wunder has dedicated himself to the presentation of this action and the suggestion that his conduct of this action should be reviewed by the Office of the Official Guardian is totally unfounded and is not warranted in this action. I want the record to indicate that although I have not agreed with many of the submissions of Mr. Wunder, and have ruled against him on some occasions in this trial, I see no reason to alter my views that Mr. Wunder is attempting to act in the best interests of his clients and perceives that his actions are in the best interests of his clients.

6. The Trial Judge Showed Antipathy to Mrs. Marchand in His Reasons for Judgment

[169] The appellants submit that the trial judge's reasons reflect his antipathy towards Mrs. Marchand. They argue that the trial judge rejected her evidence except where it bolstered the respondents' defence abruption theory and that he suggested in his reasons Mrs. Marchand "sought success in this case in priority to Joel's well-being". The appellants gave three examples of the trial judge's alleged antipathy. We will briefly review each example. None of them supports the appellants' submission.

[170] First, the appellants point to the trial judge's discussion of Joel's life expectancy. In that discussion, the trial judge expressed reservations about Mrs. Marchand's beliefs concerning her son's abilities and her reaction to professional advice for Joel's care.

[171] The trial judge thoroughly considered the question of Joel's life expectancy, devoting nearly 200 pages of his reasons to it. He praised Mrs. Marchand as a devoted, loving and caring mother who was trying to do the best for her son. The trial judge, however, was concerned about the divergence

2000 CanLII 16946 (ON CA)

between Mrs. Marchand's evidence and the expert evidence, especially on the key issue of Joel's mobility. On that issue, everyone accepted the importance of the evidence of Dr. Richard Eyman, a defence expert in epidemiology and biostatistics, who had developed a scale to predict life expectancy based on physical skills. In assessing Joel's mobility, the trial judge took into account the optimistic beliefs expressed by Mrs. Marchand and two of her friends, and compared them with the 41/2 hours of videotapes of Joel, the evidence of Joel's physiotherapist and the evidence of a doctor who participated in the defence medical (examination of Joel).

[172] The trial judge concluded that he could find no acceptable evidence that Joel could crawl, scoot or roll, which are key Eyman criteria. The trial judge was concerned that the appellants' efforts to suggest otherwise had their genesis in the Eyman criteria, a concern that was heightened by the apparently overstated information Mr. and Mrs. Marchand gave to Dr. MacGregor, who assessed Joel's mobility just before trial. The beliefs that Mrs. Marchand maintained about Joel's ability are entirely understandable, but the trial judge was entitled to discount those beliefs when they clashed with the expert evidence. In our view, the trial judge's unwillingness to accept Mrs. Marchand's evidence on Joel's mobility does not reflect antipathy toward her but a fair weighing of all the evidence presented to him.

[173] The second example that the appellants rely on is the trial judge's finding on reduced fetal movements. The appellants argued at trial that Dr. Asher was negligent because he failed to tell Mrs. Marchand to count her baby's movements. This argument could succeed only if the evidence showed a significant reduction in fetal movements. There was no such evidence. The trial judge accepted Mrs. Marchand's testimony that some reduction in fetal movements had occurred but he did not elevate her testimony to support a finding of significant reduction. This does not substantiate a claim of bias.

[174] Finally, the appellants complain that the trial judge accepted Dr. Kirsch's evidence about a discussion he had with Mrs. Marchand after Joel was born. Dr. Kirsch said that during

2000 CanLII 16946 (ON CA)

an office assessment Mrs. Marchand told him that at the time of abruption she had suffered pain concurrently with a fall in the fetal heart rate. This evidence was adverse to Mrs. Marchand's interests and she was not asked about it in examination-in-chief or in re-examination. Nonetheless, the trial judge accepted Dr. Kirsch's evidence. Doing so cannot be equated with antipathy towards Mrs. Marchand.

[175] Overall, we are satisfied that the evidence reasonably supports the trial judge's findings of credibility. Mrs. Marchand overstated her evidence, albeit understandably, and the trial judge was justified in concluding that her evidence did not withstand scrutiny.

7. The Cumulative Effect

[176] The appellants submit that the trial judge's conduct, as described in the six categories above, cumulatively amounts to judicial bias. We reject this submission.

[177] We have dealt with the appellants' submissions relating to individual complaints in each of the six categories and found that none of the conduct complained about established judicial bias. However, the principles in S. (R.D.) call for a consideration of the cumulative effect of the allegations of bias. For this reason, we must consider whether the totality of the appellants' complaints gives rise to a reasonable apprehension of bias. We do not think that they do.

[178] In our opinion the relentless acrimony between counsel in this complex and lengthy case did not prevent the trial judge from conducting and judging the case fairly and thoroughly. We are satisfied that a reasonably informed person, observing the trial judge's conduct during the entire trial and reading his reasons for judgment, would have no difficulty in concluding that he remained impartial and that he demonstrated no actual or apprehended bias.

[179] We therefore also dismiss this ground of appeal.

IV. COSTS

2000 CanLII 16946 (ON CA)

[180] The trial judge awarded the respondents their party-and-party costs of the trial, which he fixed in the total amount of $2,154,447.85 ($1,233,791.25 payable to Dr. Asher and $920,656.60 payable to the other respondents). The trial judge ordered that O.H.I.P. pay a small portion of those costs and the appellants the remainder. He also dismissed a defence motion to have Mr. Wunder pay 70% of the cost award.

[181] The appellants appeal the costs order. They submit that we should deny the respondents their costs of the trial even if we dismiss the appellants' appeal. In their factums filed on appeal, the respondents sought to maintain the trial judge's costs award. In oral argument, however, counsel for all respondents undertook not to pursue the appellants for the costs of the trial and stated that the respondents were not seeking costs of this appeal. In light of this concession and the tragic event that led to this case we think it appropriate to vary the costs order at trial to provide that the appellants have no obligation for the respondents' costs.

V. CONCLUSION

[182] For the foregoing reasons, paras. 2 and 3 of the judgment at trial are set aside, to be replaced by an order that the dismissal of the action is without costs. This appeal is dismissed without costs.

Order accordingly.

Notes

Note 1: Rule 53.03 has since been amended to require earlier service of the report, and to allow supplementary reports.

Note 2: The trial judge dismissed both of the appellant's motions.

2000 CanLII 16946 (ON CA)

TAB 4

R.S.O. 1990, CHAPTER S.22

Statutory Powers Procedure Act

CURRENT Consolidation period: December 4, 2024 - e-Laws currency date (December 31, 2024)

Last amendment: 2024, c. 28, Sched. 25, s. 1, 2.

Not-yet-in-force provisions appear in consolidated law as **text with a grey background** and are accompanied by related editorial notes.

Legislative History

Table of contents

Interpretation

1 (1) In this Act,

"electronic hearing" means a hearing held by conference telephone or some other form of electronic technology allowing persons to hear one another; ("audience électronique")

"hearing" means a hearing in any proceeding; ("audience")

"licence" includes any permit, certificate, approval, registration or similar form of permission required by law; ("autorisation")

"municipality" has the same meaning as in the *Municipal Affairs Act*; ("municipalité")

"oral hearing" means a hearing at which the parties or their representatives attend before the tribunal in person; ("audience orale")

"proceeding" means a proceeding to which this Act applies; ("instance")

"representative" means, in respect of a proceeding to which this Act applies, a person authorized under the *Law Society Act* to represent a person in that proceeding; ("représentant")

"statutory power of decision" means a power or right, conferred by or under a statute, to make a decision deciding or prescribing,

(a) the legal rights, powers, privileges, immunities, duties or liabilities of any person or party, or

(b) the eligibility of any person or party to receive, or to the continuation of, a benefit or licence, whether the person is legally entitled thereto or not; ("compétence légale de décision")

"tribunal" means one or more persons, whether or not incorporated and however described, upon which a statutory power of decision is conferred by or under a statute; ("tribunal")

"written hearing" means a hearing held by means of the exchange of documents, whether in written form or by electronic means. ("audience écrite") R.S.O. 1990, c. S.22, s. 1 (1); 1994, c. 27, s. 56 (1-3); 2002, c. 17, Sched. F, Table; 2006, c. 21, Sched. C, s. 134 (1, 2).

Meaning of "person" extended

(2) A municipality, an unincorporated association of employers, a trade union or council of trade unions who may be a party to a proceeding in the exercise of a statutory power of decision under the statute conferring the power shall be deemed to be a person for the purpose of any provision of this Act or of any rule made under this Act that applies to parties. R.S.O. 1990, c. S.22, s. 1 (2).

Section Amendments with date in force (d/m/y)

Liberal construction of Act and rules

2 This Act, and any rule made by a tribunal under subsection 17.1 (4) or section 25.1, shall be liberally construed to secure the just, most expeditious and cost-effective determination of every proceeding on its merits. 1999, c. 12, Sched. B, s. 16 (1); 2006, c. 19, Sched. B, s. 21 (1).

Section Amendments with date in force (d/m/y)

Application of Act

3 (1) Subject to subsection (2), this Act applies to a proceeding by a tribunal in the exercise of a statutory power of decision conferred by or under an Act of the Legislature, where the tribunal is required by or under such Act or otherwise by law to hold or to afford to the parties to the proceeding an opportunity for a hearing before making a decision. R.S.O. 1990, c. S.22, s. 3 (1); 1994, c. 27, s. 56 (5).

Where Act does not apply

(2) This Act does not apply to a proceeding,

(a) before the Assembly or any committee of the Assembly;

(b) in or before,

(i) the Court of Appeal,

(ii) the Superior Court of Justice,

(iii) the Ontario Court of Justice,

(iv) the Family Court of the Superior Court of Justice,

(v) the Small Claims Court, or

(vi) a justice of the peace;

(c) to which the Rules of Civil Procedure apply;

(d) before an arbitrator to which the *Arbitration Act, 1991* or the *Labour Relations Act, 1995* applies;

(e) at a coroner's inquest;

(f) of a commission appointed under the *Public Inquiries Act, 2009*;

(g) of one or more persons required to make an investigation and to make a report, with or without recommendations, where the report is for the information or advice of the person to whom it is made and does not in any way legally bind or limit that person in any decision he or she may have power to make; or

(h) of a tribunal empowered to make regulations, rules or by-laws in so far as its power to make regulations, rules or by-laws is concerned. R.S.O. 1990, c. S.22, s. 3 (2); 1994, c. 27, s. 56 (6); 2006, c. 19, Sched. C, s. 1 (1, 2, 4); 2009, c. 33, Sched. 6, s. 87; 2021, c. 25, Sched. 27, s. 1.

Section Amendments with date in force (d/m/y)

Waiver

Waiver of procedural requirement

4 (1) Any procedural requirement of this Act, or of another Act or a regulation that applies to a proceeding, may be waived with the consent of the parties and the tribunal. 1997, c. 23, s. 13 (1).

Same, rules

(2) Any provision of a tribunal's rules made under section 25.1 may be waived in accordance with the rules. 1994, c. 27, s. 56 (7).

v **Section Amendments with date in force (d/m/y)**

Disposition without hearing

4.1 If the parties consent, a proceeding may be disposed of by a decision of the tribunal given without a hearing, unless another Act or a regulation that applies to the proceeding provides otherwise. 1997, c. 23, s. 13 (2).

v **Section Amendments with date in force (d/m/y)**

Panels, certain matters

4.2 (1) A procedural or interlocutory matter in a proceeding may be heard and determined by a panel consisting of one or more members of the tribunal, as assigned by the chair of the tribunal. 1994, c. 27, s. 56 (8).

Assignments

(2) In assigning members of the tribunal to a panel, the chair shall take into consideration any requirement imposed by another Act or a regulation that applies to the proceeding that the tribunal be representative of specific interests. 1997, c. 23, s. 13 (3).

Decision of panel

(3) The decision of a majority of the members of a panel, or their unanimous decision in the case of a two-member panel, is the tribunal's decision. 1994, c. 27, s. 56 (8).

v **Section Amendments with date in force (d/m/y)**

Panel of one, reduced panel

Panel of one

4.2.1 (1) The chair of a tribunal may decide that a proceeding be heard by a panel of one person and assign the person to hear the proceeding unless there is a statutory requirement in another Act that the proceeding be heard by a panel of more than one person.

Reduction in number of panel members

(2) Where there is a statutory requirement in another Act that a proceeding be heard by a panel of a specified number of persons, the chair of the tribunal may assign to the panel one person or any lesser number of persons than the number specified in the other Act if all parties to the proceeding consent. 1999, c. 12, Sched. B, s. 16 (2).

Section Amendments with date in force (d/m/y)

Expiry of term

4.3 If the term of office of a member of a tribunal who has participated in a hearing expires before a decision is given, the term shall be deemed to continue, but only for the purpose of participating in the decision and for no other purpose. 1997, c. 23, s. 13 (4).

Section Amendments with date in force (d/m/y)

Incapacity of member

4.4 (1) If a member of a tribunal who has participated in a hearing becomes unable, for any reason, to complete the hearing or to participate in the decision, the remaining member or members may complete the hearing and give a decision. 1994, c. 27, s. 56 (9).

Other Acts and regulations

(2) Subsection (1) does not apply if another Act or a regulation specifically deals with the issue of what takes place in the circumstances described in subsection (1). 1997, c. 23, s. 13 (5).

Note: On a day to be named by proclamation of the Lieutenant Governor, section 4.4 of the *Statutory Powers Procedure Act* is repealed and the following substituted: (See:

2024, c. 28, Sched. 25, s. 1)

Incapacity, failure to complete hearing or make decision

Incapacity, panel of one

4.4 (1) In the case of a panel of one person, if the person dies or is or appears to be, for any other reason, unable to complete a hearing or to make a decision, the chair of the tribunal may, on a party's motion to the tribunal or on the chair's own initiative, assign another panel to complete the hearing or make a decision in the person's place. 2024, c. 28, Sched. 25, s. 1.

Incapacity, panel of more than one

(2) In the case of a panel of more than one person, if a member of the panel dies or is unable for any other reason to complete a hearing or to participate in a decision, the remaining member or members may complete the hearing or make a decision. 2024, c. 28, Sched. 25, s. 1.

Failure to meet reasonable time frame

(3) If the chair of the tribunal is of the opinion that a panel has failed to complete a hearing or make a decision within a reasonable time, the chair may specify a deadline by which the panel must complete the hearing or make a decision. 2024, c. 28, Sched. 25, s. 1.

Same

(4) For the purposes of subsection (3), the chair of the tribunal,

(a) shall consider,

(i) the guidelines established by the tribunal under section 16.2, and

(ii) the service standard policy developed by the tribunal under section 5 of the *Adjudicative Tribunals Accountability, Governance and Appointments Act, 2009*, if applicable; and

(b) may consider any other matter that, in the chair's opinion, is relevant in the circumstances. 2024, c. 28, Sched. 25, s. 1.

Failure to meet specified deadline

(5) If a panel fails to meet a deadline specified under subsection (3), the chair of the tribunal may, on a party's motion to the tribunal or on the chair's own initiative, assign another panel to complete the hearing or make a decision in the first panel's place. 2024, c. 28, Sched. 25, s. 1.

If assigned to another panel

(6) The panel assigned under subsection (1) or (5) shall determine whether to,

(a) continue the hearing or make a decision on the basis of the existing evidentiary record, subject to subsection (8); or

(b) rehear the proceeding. 2024, c. 28, Sched. 25, s. 1.

Same, submissions

(7) If the panel permits, the parties to the proceeding may make submissions on the determination to be made by the panel under subsection (6). 2024, c. 28, Sched. 25, s. 1.

Same, powers

(8) Despite clause (6) (a), the panel may, during or after the hearing, recall a witness or require further evidence. 2024, c. 28, Sched. 25, s. 1.

Other Acts and regulations

(9) This section is subject to any other Act or regulation that applies to the proceeding. 2024, c. 28, Sched. 25, s. 1.

Section Amendments with date in force (d/m/y)

Decision not to process commencement of proceeding

4.5 (1) Subject to subsection (3), upon receiving documents relating to the commencement of a proceeding, a tribunal or its administrative staff may decide not to process the

documents relating to the commencement of the proceeding if,

(a) the documents are incomplete;

(b) the documents are received after the time required for commencing the proceeding has elapsed;

(c) the fee required for commencing the proceeding is not paid; or

(d) there is some other technical defect in the commencement of the proceeding.

Notice

(2) A tribunal or its administrative staff shall give the party who commences a proceeding notice of its decision under subsection (1) and shall set out in the notice the reasons for the decision and the requirements for resuming the processing of the documents.

Rules under s. 25.1

(3) A tribunal or its administrative staff shall not make a decision under subsection (1) unless the tribunal has made rules under section 25.1 respecting the making of such decisions and those rules shall set out,

(a) any of the grounds referred to in subsection (1) upon which the tribunal or its administrative staff may decide not to process the documents relating to the commencement of a proceeding; and

(b) the requirements for the processing of the documents to be resumed.

Continuance of provisions in other statutes

(4) Despite section 32, nothing in this section shall prevent a tribunal or its administrative staff from deciding not to process documents relating to the commencement of a proceeding on grounds that differ from those referred to in subsection (1) or without complying with subsection (2) or (3) if the tribunal or its staff does so in accordance with the provisions of an Act that are in force on the day this section comes into force. 1999, c. 12, Sched. B, s. 16 (3).

Section Amendments with date in force (d/m/y)

Dismissal of proceeding without hearing

4.6 (1) Subject to subsections (5) and (6), a tribunal may dismiss a proceeding without a hearing if,

(a) the proceeding is frivolous, vexatious or is commenced in bad faith;

(b) the proceeding relates to matters that are outside the jurisdiction of the tribunal; or

(c) some aspect of the statutory requirements for bringing the proceeding has not been met.

Notice

(2) Before dismissing a proceeding under this section, a tribunal shall give notice of its intention to dismiss the proceeding to,

(a) all parties to the proceeding if the proceeding is being dismissed for reasons referred to in clause (1) (b); or

(b) the party who commences the proceeding if the proceeding is being dismissed for any other reason.

Same

(3) The notice of intention to dismiss a proceeding shall set out the reasons for the dismissal and inform the parties of their right to make written submissions to the tribunal with respect to the dismissal within the time specified in the notice.

Right to make submissions

(4) A party who receives a notice under subsection (2) may make written submissions to the tribunal with respect to the dismissal within the time specified in the notice.

Dismissal

(5) A tribunal shall not dismiss a proceeding under this section until it has given notice under subsection (2) and considered any submissions made under subsection (4).

Rules

(6) A tribunal shall not dismiss a proceeding under this section unless it has made rules under section 25.1 respecting the early dismissal of proceedings and those rules shall

include,

(a) any of the grounds referred to in subsection (1) upon which a proceeding may be dismissed;

(b) the right of the parties who are entitled to receive notice under subsection (2) to make submissions with respect to the dismissal; and

(c) the time within which the submissions must be made.

Continuance of provisions in other statutes

(7) Despite section 32, nothing in this section shall prevent a tribunal from dismissing a proceeding on grounds other than those referred to in subsection (1) or without complying with subsections (2) to (6) if the tribunal dismisses the proceeding in accordance with the provisions of an Act that are in force on the day this section comes into force. 1999, c. 12, Sched. B, s. 16 (3).

Section Amendments with date in force (d/m/y)

Classifying proceedings

4.7 A tribunal may make rules under section 25.1 classifying the types of proceedings that come before it and setting guidelines as to the procedural steps or processes (such as preliminary motions, pre-hearing conferences, alternative dispute resolution mechanisms, expedited hearings) that apply to each type of proceeding and the circumstances in which other procedures may apply. 1999, c. 12, Sched. B, s. 16 (3).

Section Amendments with date in force (d/m/y)

Alternative dispute resolution

4.8 (1) A tribunal may direct the parties to a proceeding to participate in an alternative dispute resolution mechanism for the purposes of resolving the proceeding or an issue arising in the proceeding if,

(a) it has made rules under section 25.1 respecting the use of alternative dispute resolution mechanisms; and

(b) all parties consent to participating in the alternative dispute resolution mechanism.

Definition

(2) In this section,

"alternative dispute resolution mechanism" includes mediation, conciliation, negotiation or any other means of facilitating the resolution of issues in dispute.

Rules

(3) A rule under section 25.1 respecting the use of alternative dispute resolution mechanisms shall include procedural guidelines to deal with the following:

1. The circumstances in which a settlement achieved by means of an alternative dispute resolution mechanism must be reviewed and approved by the tribunal.

2. Any requirement, statutory or otherwise, that there be an order by the tribunal.

Mandatory alternative dispute resolution

(4) A rule under subsection (3) may provide that participation in an alternative dispute resolution mechanism is mandatory or that it is mandatory in certain specified circumstances.

Person appointed to mediate, etc.

(5) A rule under subsection (3) may provide that a person appointed to mediate, conciliate, negotiate or help resolve a matter by means of an alternative dispute resolution mechanism be a member of the tribunal or a person independent of the tribunal. However, a member of the tribunal who is so appointed with respect to a matter in a proceeding shall not subsequently hear the matter if it comes before the tribunal unless the parties consent.

Continuance of provisions in other statutes

(6) Despite section 32, nothing in this section shall prevent a tribunal from directing parties to a proceeding to participate in an alternative dispute resolution mechanism even though the requirements of subsections (1) to (5) have not been met if the tribunal does so in accordance with the provisions of an Act that are in force on the day this section comes into force. 1999, c. 12, Sched. B, s. 16 (3).

Section Amendments with date in force (d/m/y)

Mediators, etc.: not compellable, notes not evidence

Mediators, etc., not compellable

4.9 (1) No person employed as a mediator, conciliator or negotiator or otherwise appointed to facilitate the resolution of a matter before a tribunal by means of an alternative dispute resolution mechanism shall be compelled to give testimony or produce documents in a proceeding before the tribunal or in a civil proceeding with respect to matters that come to his or her knowledge in the course of exercising his or her duties under this or any other Act.

Evidence in civil proceedings

(2) No notes or records kept by a mediator, conciliator or negotiator or by any other person appointed to facilitate the resolution of a matter before a tribunal by means of an alternative dispute resolution mechanism under this or any other Act are admissible in a civil proceeding. 1999, c. 12, Sched. B, s. 16 (3).

Section Amendments with date in force (d/m/y)

Parties

5. The parties to a proceeding shall be the persons specified as parties by or under the statute under which the proceeding arises or, if not so specified, persons entitled by law to be parties to the proceeding. R.S.O. 1990, c. S.22, s. 5.

Written hearings

5.1 (1) A tribunal whose rules made under section 25.1 deal with written hearings may hold a written hearing in a proceeding. 1997, c. 23, s. 13 (6).

Exception

(2) The tribunal shall not hold a written hearing if a party satisfies the tribunal that there is good reason for not doing so.

Same

(2.1) Subsection (2) does not apply if the only purpose of the hearing is to deal with procedural matters. 1999, c. 12, Sched. B, s. 16 (4).

Documents

(3) In a written hearing, all the parties are entitled to receive every document that the tribunal receives in the proceeding. 1994, c. 27, s. 56 (10).

∨ Section Amendments with date in force (d/m/y)

Electronic hearings

5.2 (1) A tribunal whose rules made under section 25.1 deal with electronic hearings may hold an electronic hearing in a proceeding. 1997, c. 23, s. 13 (7).

Exception

(2) The tribunal shall not hold an electronic hearing if a party satisfies the tribunal that holding an electronic rather than an oral hearing is likely to cause the party significant prejudice.

Same

(3) Subsection (2) does not apply if the only purpose of the hearing is to deal with procedural matters.

Participants to be able to hear one another

(4) In an electronic hearing, all the parties and the members of the tribunal participating in the hearing must be able to hear one another and any witnesses throughout the hearing. 1994, c. 27, s. 56 (10).

∨ Section Amendments with date in force (d/m/y)

Different kinds of hearings in one proceeding

5.2.1 A tribunal may, in a proceeding, hold any combination of written, electronic and oral hearings. 1997, c. 23, s. 13 (8).

∨ Section Amendments with date in force (d/m/y)

Pre-hearing conferences

5.3 (1) If the tribunal's rules made under section 25.1 deal with pre-hearing conferences, the tribunal may direct the parties to participate in a pre-hearing conference to consider,

(a) the settlement of any or all of the issues;

(b) the simplification of the issues;

(c) facts or evidence that may be agreed upon;

(d) the dates by which any steps in the proceeding are to be taken or begun;

(e) the estimated duration of the hearing; and

(f) any other matter that may assist in the just and most expeditious disposition of the proceeding. 1994, c. 27, s. 56 (11); 1997, c. 23, s. 13 (9).

Other Acts and regulations

(1.1) The tribunal's power to direct the parties to participate in a pre-hearing conference is subject to any other Act or regulation that applies to the proceeding. 1997, c. 23, s. 13 (10).

Who presides

(2) The chair of the tribunal may designate a member of the tribunal or any other person to preside at the pre-hearing conference.

Orders

(3) A member who presides at a pre-hearing conference may make such orders as he or she considers necessary or advisable with respect to the conduct of the proceeding, including adding parties.

Disqualification

(4) A member who presides at a pre-hearing conference at which the parties attempt to settle issues shall not preside at the hearing of the proceeding unless the parties consent. 1994, c. 27, s. 56 (11).

Application of s. 5.2

(5) Section 5.2 applies to a pre-hearing conference, with necessary modifications. 1997, c. 23, s. 13 (10).

Section Amendments with date in force (d/m/y)

Disclosure

5.4 (1) If the tribunal's rules made under section 25.1 deal with disclosure, the tribunal may, at any stage of the proceeding before all hearings are complete, make orders for,

(a) the exchange of documents;

(b) the oral or written examination of a party;

(c) the exchange of witness statements and reports of expert witnesses;

(d) the provision of particulars;

(e) any other form of disclosure. 1994, c. 27, s. 56 (12); 1997, c. 23, s. 13 (11).

Other Acts and regulations

(1.1) The tribunal's power to make orders for disclosure is subject to any other Act or regulation that applies to the proceeding. 1997, c. 23, s. 13 (12).

Exception, privileged information

(2) Subsection (1) does not authorize the making of an order requiring disclosure of privileged information. 1994, c. 27, s. 56 (12).

Section Amendments with date in force (d/m/y)

Notice of hearing

6 (1) The parties to a proceeding shall be given reasonable notice of the hearing by the tribunal. R.S.O. 1990, c. S.22, s. 6 (1).

Statutory authority

(2) A notice of a hearing shall include a reference to the statutory authority under which the hearing will be held.

Oral hearing

(3) A notice of an oral hearing shall include,

(a) a statement of the time, place and purpose of the hearing; and

(b) a statement that if the party notified does not attend at the hearing, the tribunal may proceed in the party's absence and the party will not be entitled to any further notice in the proceeding. 1994, c. 27, s. 56 (13).

Written hearing

(4) A notice of a written hearing shall include,

(a) a statement of the date and purpose of the hearing, and details about the manner in which the hearing will be held;

(b) a statement that the hearing shall not be held as a written hearing if the party satisfies the tribunal that there is good reason for not holding a written hearing (in which case the tribunal is required to hold it as an electronic or oral hearing) and an indication of the procedure to be followed for that purpose;

(c) a statement that if the party notified neither acts under clause (b) nor participates in the hearing in accordance with the notice, the tribunal may proceed without the party's participation and the party will not be entitled to any further notice in the proceeding. 1994, c. 27, s. 56 (13); 1997, c. 23, s. 13 (13); 1999, c. 12, Sched. B, s. 16 (5).

Electronic hearing

(5) A notice of an electronic hearing shall include,

(a) a statement of the time and purpose of the hearing, and details about the manner in which the hearing will be held;

(b) a statement that the only purpose of the hearing is to deal with procedural matters, if that is the case;

(c) if clause (b) does not apply, a statement that the party notified may, by satisfying the tribunal that holding the hearing as an electronic hearing is likely to cause the party significant prejudice, require the tribunal to hold the hearing as an oral hearing, and an indication of the procedure to be followed for that purpose; and

(d) a statement that if the party notified neither acts under clause (c), if applicable, nor participates in the hearing in accordance with the notice, the tribunal may proceed

without the party's participation and the party will not be entitled to any further notice in the proceeding. 1994, c. 27, s. 56 (13).

---

v **Section Amendments with date in force (d/m/y)**

Effect of non-attendance at hearing after due notice

7 (1) Where notice of an oral hearing has been given to a party to a proceeding in accordance with this Act and the party does not attend at the hearing, the tribunal may proceed in the absence of the party and the party is not entitled to any further notice in the proceeding. R.S.O. 1990, c. S.22, s. 7; 1994, c. 27, s. 56 (14).

Same, written hearings

(2) Where notice of a written hearing has been given to a party to a proceeding in accordance with this Act and the party neither acts under clause 6 (4) (b) nor participates in the hearing in accordance with the notice, the tribunal may proceed without the party's participation and the party is not entitled to any further notice in the proceeding.

Same, electronic hearings

(3) Where notice of an electronic hearing has been given to a party to a proceeding in accordance with this Act and the party neither acts under clause 6 (5) (c), if applicable, nor participates in the hearing in accordance with the notice, the tribunal may proceed without the party's participation and the party is not entitled to any further notice in the proceeding. 1994, c. 27, s. 56 (15).

---

v **Section Amendments with date in force (d/m/y)**

Where character, etc., of a party is in issue

8. Where the good character, propriety of conduct or competence of a party is an issue in a proceeding, the party is entitled to be furnished prior to the hearing with reasonable information of any allegations with respect thereto. R.S.O. 1990, c. S.22, s. 8.

Hearings to be public; maintenance of order

Hearings to be public, exceptions

9 (1) An oral hearing shall be open to the public except where the tribunal is of the opinion that,

(a) matters involving public security may be disclosed; or

(b) intimate financial or personal matters or other matters may be disclosed at the hearing of such a nature, having regard to the circumstances, that the desirability of avoiding disclosure thereof in the interests of any person affected or in the public interest outweighs the desirability of adhering to the principle that hearings be open to the public,

in which case the tribunal may hold the hearing in the absence of the public. R.S.O. 1990, c. S.22, s. 9 (1); 1994, c. 27, s. 56 (16).

Written hearings

(1.1) In a written hearing, members of the public are entitled to reasonable access to the documents submitted, unless the tribunal is of the opinion that clause (1) (a) or (b) applies. 1994, c. 27, s. 56 (17).

Electronic hearings

(1.2) An electronic hearing shall be open to the public unless the tribunal is of the opinion that,

(a) it is not practical to hold the hearing in a manner that is open to the public; or

(b) clause (1) (a) or (b) applies. 1997, c. 23, s. 13 (14).

Maintenance of order at hearings

(2) A tribunal may make such orders or give such directions at an oral or electronic hearing as it considers necessary for the maintenance of order at the hearing, and, if any person disobeys or fails to comply with any such order or direction, the tribunal or a member thereof may call for the assistance of any peace officer to enforce the order or direction, and every peace officer so called upon shall take such action as is necessary to enforce the order

or direction and may use such force as is reasonably required for that purpose. R.S.O. 1990, c. S.22, s. 9 (2); 1994, c. 27, s. 56 (18).

Section Amendments with date in force (d/m/y)

Proceedings involving similar questions

9.1 (1) If two or more proceedings before a tribunal involve the same or similar questions of fact, law or policy, the tribunal may,

(a) combine the proceedings or any part of them, with the consent of the parties;

(b) hear the proceedings at the same time, with the consent of the parties;

(c) hear the proceedings one immediately after the other; or

(d) stay one or more of the proceedings until after the determination of another one of them.

Exception

(2) Subsection (1) does not apply to proceedings held under section 21 of the *Ontario Land Tribunal Act, 2021*. 1994, c. 27, s. 56 (19); 2021, c. 4, Sched. 6, s. 91.

Same

(3) Clauses (1) (a) and (b) do not apply to a proceeding if,

(a) any other Act or regulation that applies to the proceeding requires that it be heard in private;

(b) the tribunal is of the opinion that clause 9 (1) (a) or (b) applies to the proceeding. 1994, c. 27, s. 56 (19); 1997, c. 23, s. 13 (15).

Conflict, consent requirements

(4) The consent requirements of clauses (1) (a) and (b) do not apply if another Act or a regulation that applies to the proceedings allows the tribunal to combine them or hear them at the same time without the consent of the parties. 1997, c. 23, s. 13 (16).

Use of same evidence

(5) If the parties to the second-named proceeding consent, the tribunal may treat evidence that is admitted in a proceeding as if it were also admitted in another proceeding that is heard at the same time under clause (1) (b). 1994, c. 27, s. 56 (19).

v Section Amendments with date in force (d/m/y)

Right to representation

10 A party to a proceeding may be represented by a representative. 2006, c. 21, Sched. C, s. 134 (3).

v Section Amendments with date in force (d/m/y)

Examination of witnesses

10.1 A party to a proceeding may, at an oral or electronic hearing,

(a) call and examine witnesses and present evidence and submissions; and

(b) conduct cross-examinations of witnesses at the hearing reasonably required for a full and fair disclosure of all matters relevant to the issues in the proceeding. 1994, c. 27, s. 56 (20).

v Section Amendments with date in force (d/m/y)

Rights of witnesses to representation

11 (1) A witness at an oral or electronic hearing is entitled to be advised by a representative as to his or her rights, but such representative may take no other part in the hearing without leave of the tribunal. 2006, c. 21, Sched. C, s. 134 (4).

Idem

(2) Where an oral hearing is closed to the public, the witness's representative is not entitled to be present except when that witness is giving evidence. R.S.O. 1990, c. S.22, s. 11 (2); 1994, c. 27, s. 56 (22); 2006, c. 21, Sched. C, s. 134 (5).

Section Amendments with date in force (d/m/y)

Summonses

12 (1) A tribunal may require any person, including a party, by summons,

(a) to give evidence on oath or affirmation at an oral or electronic hearing; and

(b) to produce in evidence at an oral or electronic hearing documents and things specified by the tribunal,

relevant to the subject-matter of the proceeding and admissible at a hearing. R.S.O. 1990, c. S.22, s. 12 (1); 1994, c. 27, s. 56 (23).

Form and service of summons

(2) A summons issued under subsection (1) shall be in the prescribed form (in English or French) and,

(a) where the tribunal consists of one person, shall be signed by him or her;

(b) where the tribunal consists of more than one person, shall be signed by the chair of the tribunal or in such other manner as documents on behalf of the tribunal may be signed under the statute constituting the tribunal. 1994, c. 27, s. 56 (24).

Same

(3) The summons shall be served personally on the person summoned. 1994, c. 27, s. 56 (24).

Fees and allowances

(3.1) The person summoned is entitled to receive the same fees or allowances for attending at or otherwise participating in the hearing as are paid to a person summoned to attend before the Superior Court of Justice. 1994, c. 27, s. 56 (24); 2006, c. 19, Sched. C, s. 1 (1).

Bench warrant

(4) A judge of the Superior Court of Justice may issue a warrant against a person if the judge is satisfied that,

(a) a summons was served on the person under this section;

(b) the person has failed to attend or to remain in attendance at the hearing (in the case of an oral hearing) or has failed otherwise to participate in the hearing (in the case of an electronic hearing) in accordance with the summons; and

(c) the person's attendance or participation is material to the ends of justice. 1994, c. 27, s. 56 (25); 2006, c. 19, Sched. C, s. 1 (1).

Same

(4.1) The warrant shall be in the prescribed form (in English or French), directed to any police officer, and shall require the person to be apprehended anywhere within Ontario, brought before the tribunal forthwith and,

(a) detained in custody as the judge may order until the person's presence as a witness is no longer required; or

(b) in the judge's discretion, released on a recognizance, with or without sureties, conditioned for attendance or participation to give evidence. 1994, c. 27, s. 56 (25).

Proof of service

(5) Service of a summons may be proved by affidavit in an application to have a warrant issued under subsection (4). 1994, c. 27, s. 56 (26).

Certificate of facts

(6) Where an application to have a warrant issued is made on behalf of a tribunal, the person constituting the tribunal or, if the tribunal consists of more than one person, the chair of the tribunal may certify to the judge the facts relied on to establish that the attendance or other participation of the person summoned is material to the ends of justice, and the judge may accept the certificate as proof of the facts. 1994, c. 27, s. 56 (26).

Same

(7) Where the application is made by a party to the proceeding, the facts relied on to establish that the attendance or other participation of the person is material to the ends of justice may be proved by the party's affidavit. 1994, c. 27, s. 56 (26).

Section Amendments with date in force (d/m/y)

Contempt proceedings

13 (1) Where any person without lawful excuse,

(a) on being duly summoned under section 12 as a witness at a hearing makes default in attending at the hearing; or

(b) being in attendance as a witness at an oral hearing or otherwise participating as a witness at an electronic hearing, refuses to take an oath or to make an affirmation legally required by the tribunal to be taken or made, or to produce any document or thing in his or her power or control legally required by the tribunal to be produced by him or her or to answer any question to which the tribunal may legally require an answer; or

(c) does any other thing that would, if the tribunal had been a court of law having power to commit for contempt, have been contempt of that court,

the tribunal may, of its own motion or on the motion of a party to the proceeding, state a case to the Divisional Court setting out the facts and that court may inquire into the matter and, after hearing any witnesses who may be produced against or on behalf of that person and after hearing any statement that may be offered in defence, punish or take steps for the punishment of that person in like manner as if he or she had been guilty of contempt of the court. R.S.O. 1990, c. S.22, s. 13; 1994, c. 27, s. 56 (27).

Same

(2) Subsection (1) also applies to a person who,

(a) having objected under clause 6 (4) (b) to a hearing being held as a written hearing, fails without lawful excuse to participate in the oral or electronic hearing of the matter; or

(b) being a party, fails without lawful excuse to attend a pre-hearing conference when so directed by the tribunal. 1997, c. 23, s. 13 (17).

Section Amendments with date in force (d/m/y)

Protection for witnesses

14 (1) A witness at an oral or electronic hearing shall be deemed to have objected to answer any question asked him or her upon the ground that the answer may tend to criminate him or her or may tend to establish his or her liability to civil proceedings at the instance of the Crown, or of any person, and no answer given by a witness at a hearing shall be used or be receivable in evidence against the witness in any trial or other proceeding against him or her thereafter taking place, other than a prosecution for perjury in giving such evidence. R.S.O. 1990, c. S.22, s. 14 (1); 1994, c. 27, s. 56 (28);. 2021, c. 25, Sched. 27, s. 2.

(2) Repealed: 1994, c. 27, s. 56 (29).

Section Amendments with date in force (d/m/y)

Evidence

What is admissible in evidence at a hearing

15 (1) Subject to subsections (2) and (3), a tribunal may admit as evidence at a hearing, whether or not given or proven under oath or affirmation or admissible as evidence in a court,

(a) any oral testimony; and

(b) any document or other thing,

relevant to the subject-matter of the proceeding and may act on such evidence, but the tribunal may exclude anything unduly repetitious.

What is inadmissible in evidence at a hearing

(2) Nothing is admissible in evidence at a hearing,

(a) that would be inadmissible in a court by reason of any privilege under the law of evidence; or

(b) that is inadmissible by the statute under which the proceeding arises or any other statute.

Conflicts

(3) Nothing in subsection (1) overrides the provisions of any Act expressly limiting the extent to or purposes for which any oral testimony, documents or things may be admitted or used in evidence in any proceeding.

Copies

(4) Where a tribunal is satisfied as to its authenticity, a copy of a document or other thing may be admitted as evidence at a hearing.

Photocopies

(5) Where a document has been filed in evidence at a hearing, the tribunal may, or the person producing it or entitled to it may with the leave of the tribunal, cause the document to be photocopied and the tribunal may authorize the photocopy to be filed in evidence in the place of the document filed and release the document filed, or may furnish to the person producing it or the person entitled to it a photocopy of the document filed certified by a member of the tribunal.

Certified copy admissible in evidence

(6) A document purporting to be a copy of a document filed in evidence at a hearing, certified to be a copy thereof by a member of the tribunal, is admissible in evidence in proceedings in which the document is admissible as evidence of the document. R.S.O. 1990, c. S.22, s. 15.

Use of previously admitted evidence

15.1 (1) The tribunal may treat previously admitted evidence as if it had been admitted in a proceeding before the tribunal, if the parties to the proceeding consent. 1994, c. 27, s. 56 (30).

Definition

(2) In subsection (1),

"previously admitted evidence" means evidence that was admitted, before the hearing of the proceeding referred to in that subsection, in any other proceeding before a court or tribunal, whether in or outside Ontario.

Additional power

(3) This power conferred by this section is in addition to the tribunal's power to admit evidence under section 15. 1997, c. 23, s. 13 (18).

Section Amendments with date in force (d/m/y)

Witness panels

15.2 A tribunal may receive evidence from panels of witnesses composed of two or more persons, if the parties have first had an opportunity to make submissions in that regard. 1994, c. 27, s. 56 (31).

Section Amendments with date in force (d/m/y)

Notice of facts and opinions

16 A tribunal may, in making its decision in any proceeding,

(a) take notice of facts that may be judicially noticed; and

(b) take notice of any generally recognized scientific or technical facts, information or opinions within its scientific or specialized knowledge. R.S.O. 1990, c. S.22, s. 16.

Interim decisions and orders

16.1 (1) A tribunal may make interim decisions and orders.

Conditions

(2) A tribunal may impose conditions on an interim decision or order.

Reasons

(3) An interim decision or order need not be accompanied by reasons. 1994, c. 27, s. 56 (32).

Section Amendments with date in force (d/m/y)

Time frames

16.2 A tribunal shall establish guidelines setting out the usual time frame for completing proceedings that come before the tribunal and for completing the procedural steps within those proceedings. 1999, c. 12, Sched. B, s. 16 (6).

Note: On a day to be named by proclamation of the Lieutenant Governor, section 16.2 of the Act is amended by adding "and make publicly available" after "shall establish". (See: 2024, c. 28, Sched. 25, s. 2)

v Section Amendments with date in force (d/m/y)

Decision; interest

Decision

17 (1) A tribunal shall give its final decision and order, if any, in any proceeding in writing and shall give reasons in writing therefor if requested by a party. R.S.O. 1990, c. S.22, s. 17; 1993, c. 27, Sched.

Interest

(2) A tribunal that makes an order for the payment of money shall set out in the order the principal sum, and if interest is payable, the rate of interest and the date from which it is to be calculated. 1994, c. 27, s. 56 (33).

v Section Amendments with date in force (d/m/y)

Costs

17.1 (1) Subject to subsection (2), a tribunal may, in the circumstances set out in rules made under subsection (4), order a party to pay all or part of another party's costs in a proceeding. 2006, c. 19, Sched. B, s. 21 (2).

Exception

(2) A tribunal shall not make an order to pay costs under this section unless,

(a) the conduct or course of conduct of a party has been unreasonable, frivolous or vexatious or a party has acted in bad faith; and

(b) the tribunal has made rules under subsection (4). 2006, c. 19, Sched. B, s. 21 (2).

Amount of costs

(3) The amount of the costs ordered under this section shall be determined in accordance with the rules made under subsection (4). 2006, c. 19, Sched. B, s. 21 (2).

Rules

(4) A tribunal may make rules with respect to,

(a) the ordering of costs;

(b) the circumstances in which costs may be ordered; and

(c) the amount of costs or the manner in which the amount of costs is to be determined. 2006, c. 19, Sched. B, s. 21 (2).

Same

(5) Subsections 25.1 (3), (4), (5) and (6) apply with respect to rules made under subsection (4). 2006, c. 19, Sched. B, s. 21 (2).

Continuance of provisions in other statutes

(6) Despite section 32, nothing in this section shall prevent a tribunal from ordering a party to pay all or part of another party's costs in a proceeding in circumstances other than those set out in, and without complying with, subsections (1) to (3) if the tribunal makes the order in accordance with the provisions of an Act that are in force on February 14, 2000. 2006, c. 19, Sched. B, s. 21 (2).

Submissions must be in writing

(7) Despite sections 5.1, 5.2 and 5.2.1, submissions for a costs order, whether under subsection (1) or under an authority referred to in subsection (6), shall be made by way of written or electronic documents, unless a party satisfies the tribunal that to do so is likely to cause the party significant prejudice. 2015, c. 23, s. 5.

(8), (9) Repealed: 2015, c. 23, s. 5.

Section Amendments with date in force (d/m/y)

Notice of decision

18 (1) The tribunal shall send each party who participated in the proceeding, or the party's representative, a copy of its final decision or order, including the reasons if any have been given,

(a) by regular lettermail;

(b) by electronic transmission;

(c) by telephone transmission of a facsimile; or

(d) by some other method that allows proof of receipt, if the tribunal's rules made under section 25.1 deal with the matter. 1994, c. 27, s. 56 (34); 1997, c. 23, s. 13 (19); 2006, c. 21, Sched. C, s. 134 (6).

Use of mail

(2) If the copy is sent by regular lettermail, it shall be sent to the most recent addresses known to the tribunal and shall be deemed to be received by the party on the fifth day after the day it is mailed. 1994, c. 27, s. 56 (34).

Use of electronic or telephone transmission

(3) If the copy is sent by electronic transmission or by telephone transmission of a facsimile, it shall be deemed to be received on the day after it was sent, unless that day is a holiday, in which case the copy shall be deemed to be received on the next day that is not a holiday. 1994, c. 27, s. 56 (34).

Use of other method

(4) If the copy is sent by a method referred to in clause (1) (d), the tribunal's rules made under section 25.1 govern its deemed day of receipt. 1994, c. 27, s. 56 (34).

Failure to receive copy

(5) If a party that acts in good faith does not, through absence, accident, illness or other cause beyond the party's control, receive the copy until a later date than the deemed day of receipt, subsection (2), (3) or (4), as the case may be, does not apply. 1994, c. 27, s. 56 (34).

Section Amendments with date in force (d/m/y)

Enforcement of orders

19 (1) A certified copy of a tribunal's decision or order in a proceeding may be filed in the Superior Court of Justice by the tribunal or by a party and on filing shall be deemed to be an order of that court and is enforceable as such. 1994, c. 27, s. 56 (35); 2006, c. 19, Sched. C, s. 1 (1).

Notice of filing

(2) A party who files an order under subsection (1) shall notify the tribunal within 10 days after the filing. 1994, c. 27, s. 56 (35).

Order for payment of money

(3) On receiving a certified copy of a tribunal's order for the payment of money, the sheriff shall enforce the order as if it were an execution issued by the Superior Court of Justice. 1994, c. 27, s. 56 (35); 2006, c. 19, Sched. C, s. 1 (1).

Section Amendments with date in force (d/m/y)

Record of proceeding

20 A tribunal shall compile a record of any proceeding in which a hearing has been held which shall include,

(a) any application, complaint, reference or other document, if any, by which the proceeding was commenced;

(b) the notice of any hearing;

(c) any interlocutory orders made by the tribunal;

(d) all documentary evidence filed with the tribunal, subject to any limitation expressly imposed by any other Act on the extent to or the purposes for which any such documents may be used in evidence in any proceeding;

(e) the transcript, if any, of the oral evidence given at the hearing; and

(f) the decision of the tribunal and the reasons therefor, where reasons have been given. R.S.O. 1990, c. S.22, s. 20.

Adjournments

21 A hearing may be adjourned from time to time by a tribunal of its own motion or where it is shown to the satisfaction of the tribunal that the adjournment is required to permit an adequate hearing to be held. R.S.O. 1990, c. S.22, s. 21.

Correction of errors

21.1 A tribunal may at any time correct a typographical error, error of calculation or similar error made in its decision or order. 1994, c. 27, s. 56 (36).

---

v **Section Amendments with date in force (d/m/y)**

Power to review

21.2 (1) A tribunal may, if it considers it advisable and if its rules made under section 25.1 deal with the matter, review all or part of its own decision or order, and may confirm, vary, suspend or cancel the decision or order. 1997, c. 23, s. 13 (20).

Time for review

(2) The review shall take place within a reasonable time after the decision or order is made.

Conflict

(3) In the event of a conflict between this section and any other Act, the other Act prevails. 1994, c. 27, s. 56 (36).

---

v **Section Amendments with date in force (d/m/y)**

Administration of oaths

22 A member of a tribunal has power to administer oaths and affirmations for the purpose of any of its proceedings and the tribunal may require evidence before it to be given under oath or affirmation. R.S.O. 1990, c. S.22, s. 22.

Powers re control of proceedings

Abuse of processes

23 (1) A tribunal may make such orders or give such directions in proceedings before it as it considers proper to prevent abuse of its processes. R.S.O. 1990, c. S.22, s. 23 (1).

Limitation on examination

(2) A tribunal may reasonably limit further examination or cross-examination of a witness where it is satisfied that the examination or cross-examination has been sufficient to disclose fully and fairly all matters relevant to the issues in the proceeding. 1994, c. 27, s. 56 (37).

Exclusion of representatives

(3) A tribunal may exclude from a hearing anyone, other than a person licensed under the *Law Society Act*, appearing on behalf of a party or as an adviser to a witness if it finds that such person is not competent properly to represent or to advise the party or witness, or does not understand and comply at the hearing with the duties and responsibilities of an advocate or adviser. 2006, c. 21, Sched. C, s. 134 (7).

Section Amendments with date in force (d/m/y)

Notice, etc.

24 (1) Where a tribunal is of the opinion that because the parties to any proceeding before it are so numerous or for any other reason, it is impracticable,

(a) to give notice of the hearing; or

(b) to send its decision and the material mentioned in section 18,

to all or any of the parties individually, the tribunal may, instead of doing so, cause reasonable notice of the hearing or of its decision to be given to such parties by public advertisement or otherwise as the tribunal may direct.

Contents of notice

(2) A notice of a decision given by a tribunal under clause (1) (b) shall inform the parties of the place where copies of the decision and the reasons therefor, if reasons were given, may be obtained. R.S.O. 1990, c. S.22, s. 24.

Appeal operates as stay, exception

25. (1) An appeal from a decision of a tribunal to a court or other appellate body operates as a stay in the matter unless,

(a) another Act or a regulation that applies to the proceeding expressly provides to the contrary; or

(b) the tribunal or the court or other appellate body orders otherwise. 1997, c. 23, s. 13 (21).

Idem

(2) An application for judicial review under the *Judicial Review Procedure Act*, or the bringing of proceedings specified in subsection 2 (1) of that Act is not an appeal within the meaning of subsection (1). R.S.O. 1990, c. S.22, s. 25 (2).

Section Amendments with date in force (d/m/y)

Control of process

25.0.1 A tribunal has the power to determine its own procedures and practices and may for that purpose,

(a) make orders with respect to the procedures and practices that apply in any particular proceeding; and

(b) establish rules under section 25.1. 1999, c. 12, Sched. B, s. 16 (8).

Section Amendments with date in force (d/m/y)

Rules

25.1 (1) A tribunal may make rules governing the practice and procedure before it. 1994, c. 27, s. 56 (38).

Application

(2) The rules may be of general or particular application. 1994, c. 27, s. 56 (38).

Consistency with Acts

(3) The rules shall be consistent with this Act and with the other Acts to which they relate. 1994, c. 27, s. 56 (38).

Public access

(4) The tribunal shall make the rules available to the public in English and in French. 1994, c. 27, s. 56 (38).

Legislation Act, 2006, Part III

(5) Rules adopted under this section are not regulations as defined in Part III (Regulations) of the *Legislation Act, 2006*. 1994, c. 27, s. 56 (38); 2006, c. 21, Sched. F, s. 136 (1).

Additional power

(6) The power conferred by this section is in addition to any power to adopt rules that the tribunal may have under another Act. 1994, c. 27, s. 56 (38).

v Section Amendments with date in force (d/m/y)

Regulations

26 The Lieutenant Governor in Council may make regulations prescribing forms for the purpose of section 12. 1994, c. 27, s. 56 (41).

v Section Amendments with date in force (d/m/y)

Rules, etc., available to public

27 A tribunal shall make any rules or guidelines established under this or any other Act available for examination by the public. 1999, c. 12, Sched. B, s. 16 (9).

v Section Amendments with date in force (d/m/y)

Substantial compliance

28 Substantial compliance with requirements respecting the content of forms, notices or documents under this Act or any rule made under this or any other Act is sufficient. 1999, c. 12, Sched. B, s. 16 (9).

v Section Amendments with date in force (d/m/y)

Prohibition on photographs, recordings, dissemination

29 (1) No person shall,

(a) take or attempt to take a photograph, audio or video recording or other record capable of producing or transmitting visual or aural representations by electronic means or otherwise,

(i) at a hearing,

(ii) of any person entering or leaving the room in which a hearing is to be or has been convened, or

(iii) of any person in the building in which a hearing is to be or has been convened if there is reasonable ground for believing that the person is there for the purpose of attending or leaving the hearing, other than in an area of the building designated by the tribunal for the purpose and with the person's consent;

(b) publish, broadcast, reproduce or otherwise disseminate a photograph, recording or record taken in contravention of clause (a); or

(c) broadcast, reproduce or otherwise disseminate an audio recording described in clause (2) (b). 2021, c. 25, Sched. 27, s. 3.

Non-application

(2) Subsection (1) does not apply with respect to,

(a) the unobtrusive making of notes or sketches of events at a hearing by a person;

(b) the making of an audio recording at a hearing, unobtrusively and in a manner authorized by the tribunal, by a representative, a party acting on their own behalf or a journalist, for the sole purpose of supplementing or replacing notes; or

(c) subject to the authorization of the tribunal, any act referred to in subsection (1),

(i) if it is required for the presentation of evidence, the making of a record or any other purpose of the hearing,

(ii) with the consent of the parties and witnesses, or

(iii) in connection with any ceremonial proceeding. 2021, c. 25, Sched. 27, s. 3.

Offence and penalty

(3) Every person who contravenes subsection (1) is guilty of an offence and on conviction is liable to a fine of not more than $25,000. 2021, c. 25, Sched. 27, s. 3.

Section Amendments with date in force (d/m/y)

30, 31 REPEALED: 1994, c. 27, s. 56 (40).

Section Amendments with date in force (d/m/y)

Conflict

32 Unless it is expressly provided in any other Act that its provisions and regulations, rules or by-laws made under it apply despite anything in this Act, the provisions of this Act prevail over the provisions of such other Act and over regulations, rules or by-laws made under such other Act which conflict therewith. R.S.O. 1990, c. S.22, s. 32; 1994, c. 27, s. 56 (42).

Section Amendments with date in force (d/m/y)

33, 34 REPEALED: 1994, c. 27, s. 56 (43).

Section Amendments with date in force (d/m/y)

FORMS 1, 2 REPEALED: 1994, C. 27, S. 56 (44).

Section Amendments with date in force (d/m/y)

TAB 5

EXHIBIT LIST

Exhibit	Tab	Schedule	DESCRIPTION
A – ADMINISTRATION & APPLICATION SUMMARY			
A	1	1	Exhibit List
A	1	2	2023 Submission
A	1	3	2024 Submission
A	1	4	2025 Submission
A	1	5	Executive Summary
A	2	1	Stakeholder Engagement
A	2	2	Performance Measures and Targets Attachment 1 - 2023-2025 Performance Measures Attachment 2 - 2022 Performance Measures Results
B – BUSINESS PLAN & FINANCIAL INFORMATION			
B	1	1	IESO's Letter to the Minister Requesting Approval of 2023-2025 Business Plan
B	1	2	2023-2025 Business Plan
B	1	3	Minister's Letter Approving the IESO's 2023-2025 Business Plan
B	2	1	2022 Annual Report and Audited Financial Statements (To be filed at a later date)
C – REVENUE REQUIREMENT AND USAGE FEES			
C	1	1	Revenue Requirement and Usage Fee Methodology
C	2	1	2023-2025 Revenue Requirements and Usage Fees Attachment 1 – Actual Load and Forecast Volumes (xlsx)
C	3	1	Funding Sources Attachment 1 - Funding Sources (xlsx)

D – OPERATING EXPENDITURES			
D	1	1	OM&A Overview Attachment 1 - Summary of OM&A Expenses (Appendix 2-JA) (xlsx) Attachment 2 - OM&A Cost Driver Table (Appendix 2-JB) (xlsx)
D	1	2	OM&A Business Unit Detail Attachment 1 - OM&A Business Unit Table (Appendix 2-JC) (xlsx) Attachment 2 - Organizational Chart
D	1	3	Staffing and Compensation Attachment 1 - Employee Costs (Appendix 2-K) (xlsx) Attachment 2 - IESO Compensation Guidelines Attachment 3 - Non-Executive Total Remuneration Review
D	1	4	Corporate Policy on Procurement Attachment 1 – IESO Procurement Policy
D	2	1	Interest Expense and Investment Income
E – CAPITAL EXPENDITURES, FIXED ASSETS AND AMORTIZATION			
E	1	1	Asset Management Process Overview
E	1	2	Capital Expenditure Planning Process Overview
E	2	1	Capital Budget Overview and Progress on Capital Projects Attachment 1 - Capital Projects (Appendix 2-AA) (xlsx) Attachment 2 - Project Charter - Core Network Refresh Attachment 3 - Project Charter - Enabling Resources Program Attachment 4 - Project Summary - Space Needs Program Attachment 5 - Project Summary - Lawson Refresh Attachment 6 - Project Summary - Backup Operating Centre and Backup Data Centre Relocation Attachment 7 - Project Summary - Meter Data Management System Replacement

			Attachment 8 - Project Summary - Enabling Grid Transformation Program Attachment 9 - Material Capital Project Progress Updates Attachment 10 - $1 Million - $4 Million Capital Project Updates
E	3	1	Gross Assets and Amortization Attachment 1 - Service Life Comparison and Amortization Expense (xlsx)
F – DEFERRAL AND VARIANCE ACCOUNTS			
F	1	1	Forecast Variance Deferral Account
G – EVIDENCE RESPONDING TO PREVIOUS OEB DECISIONS			
G	1	1	Summary of Responses to OEB Decisions Attachment 1 – Progress on Implementing Recommendations from Third Party Evaluation of the Grid Innovation Fund Attachment 2 – Internal Audit Recommendations & Management Response Attachment 3 – Annual OEB Update on Market Surveillance Panel Recommendations Attachment 4 - Detail of Internal Audit Reports
G	2	1	Market Renewal Program Cost Report
G	2	2	Annual Status Report on 2017 Auditor General Report Recommendations
G	2	3	IESO 2023-2025 Regulatory Scorecard (xlsx)

Business Plan 2023-2025

Independent Electricity System Operator
September 1, 2022

ieso
Connecting Today.
Powering Tomorrow.

Table of Contents

Letter from the President & CEO **2**

2023-2025 Business Plan – IESO Priorities **4**

Introduction 4

IESO Corporate Strategy at a Glance 5

Drive and Guide the Sector's Future 6

Ensure System Reliability While Supporting Cost-Effectiveness 9

Drive Business Transformation 12

Financial Overview **15**

Detailed Financials 17

Capital 17

Full Time Equivalent (FTE) Staffing 18

Market Renewal Financials **19**

Market Renewal Program Baseline Schedule, Budget Update and Funding 19

Appendix 1 – IESO Performance Management – Measures and Targets **20**

Appendix 2 – Enterprise Risk Management **22**

Appendix 3 – Capital Spending **26**

Letter from the President & CEO

Ontario's electricity system is undergoing unprecedented transformation. Demand for electricity is forecast to grow substantially over the next two decades, driven by strong economic growth in the industrial, mining and agricultural sectors, as well as electrification of transportation. At the same time, supply conditions are tightening, with nuclear units being refurbished, the Pickering nuclear facility soon retiring, and generation contracts expiring.

Governments at all levels are moving forward with decarbonization policies, driven by community and customer preferences. While Ontario's electricity grid is well positioned to support decarbonization of the broader economy, being one of the cleanest in the world, we will need to be prepared for electrification to potentially double or triple demand over the next 20 years.

Like many jurisdictions around the world, new non-emitting resources are increasingly being integrated into the province's electricity grid. While energy storage and distributed energy resources are already playing a role in Ontario, the stage is set for these resources to take a big leap forward in the coming years.

With the increasing pace and scope of change, we felt it was time to refine and recalibrate our corporate strategy for the next five years to ensure we are well positioned to meet Ontarians' needs and expectations. For this reason, we undertook a thorough visioning process in late 2021 and early 2022 to imagine the sustainable future-state energy system that Ontario will require, and identify a series of concrete steps to deliver on future needs.

The 2023-2025 Business Plan sets out the IESO's revenue requirement and capital spending needed to maintain our critical responsibilities and deliver on our refreshed strategy.

As the system integrator, the IESO is being asked to do more with every passing year. The job of ensuring a reliable and affordable supply of electricity for Ontario's businesses, communities, residents and Indigenous peoples is becoming increasingly complex. Yet it remains crucial to power economic development and support decarbonization of the economy.

Despite the significant change underway, our electricity system is prepared for future growth, and the IESO is continuing to implement a comprehensive plan to procure new generation capacity. In parallel, we are also assessing the technical and human resource requirements to fully integrate these new resources and the energy they will eventually produce. At the same time, the IESO is actively studying how to reduce reliance on gas generation over the long term and transition to a more decarbonized electricity system.

The IESO is also continuing to integrate new non-emitting resources like energy storage and distributed energy resources, learning lessons that we can build on as we transition to a more sustainable electricity grid of the future. In addition, our energy efficiency programs continue to reduce grid demand while helping businesses save on costs, and we are looking at expanding opportunities.

Many of our initiatives are designed to drive down costs for Ontario ratepayers, and one of our integral initiatives to fulfil that goal is our Market Renewal Program (MRP). This project will bring

significant ratepayer benefits and ensure continued reliable operations as the system becomes more diversified, distributed and digitalized.

As we take proactive steps to ensure a reliable and affordable system, we must also remain vigilant to potential cybersecurity threats. Uptake of our cybersecurity services is increasing and cascading across the sector, helping to ensure local distribution companies and generation owners have access to the latest cyber intelligence. These efforts are critical as cyber threats have been identified as our primary risk.

To support our efforts, we are enhancing our engagement efforts and strengthening our outreach to municipalities, Indigenous communities and electricity consumers.

While we continue to carefully review all expenditures and seek out new efficiencies, new investments are needed. To fully prepare the sector for the future and ensure Ontarians' electricity needs are met, we must invest in our people and our systems. As a result, the IESO is proposing increases to its budget to ensure we can continue to meet Ontarians' expectations of an affordable, sustainable, resilient and reliable power system.

To deliver on this plan, the IESO has a revenue requirement of $208.4 million in 2023, $218.4 million in 2024, and $229.7 million in 2025. These figures represent increases of 5.8%, 4.8%, and 5.2% year over year. For the average residential electricity bill, this translates into an increase of 8.3 cents per month over the 2023-2025 planning period.

There are currently many exciting developments taking place across Ontario. The province is attracting new businesses, communities are developing ambitious energy plans, emerging technologies are providing more choice, and the transportation and industrial sectors are undergoing electrification.

The IESO is committed to supporting the future prosperity of the province by driving and guiding the sector's future, ensuring system reliability while supporting cost effectiveness, and driving business transformation. While this job is becoming increasingly challenging, with new investment we are confident that our comprehensive business plan and skilled workforce can continue to deliver.



Lesley Gallinger

President and CEO

2023-2025 Business Plan – IESO Priorities

Introduction

A reliable, affordable and sustainable supply of electricity is fundamental to the prosperity and well-being of Ontario's residents, businesses, institutions and communities. Each and every day, they count on the Independent Electricity System Operator (IESO) to ensure electricity is available where and when it's needed.

The IESO is here to ensure the province's power system can deliver this essential resource. By working collaboratively and purposefully with market participants, municipal officials, Indigenous communities, government bodies and a vast range of other partners in the energy sector and beyond, we operate for today, plan for tomorrow and prepare for the future.

Positioned at the heart of Ontario's electricity sector, the IESO's work impacts how electricity is produced and consumed, how it is transmitted and distributed, and how it is managed and planned for in real-time and over the longer term to ensure the province's needs are met at all times.

We play a unique and critical role in Ontario's energy ecosystem – and in the province as a whole. For more than a decade now, the electricity landscape has been experiencing an unprecedented transformation, and the pace of change shows no signs of slowing.

Facing these changes head-on, we are setting a course for a future state that is decarbonized, decentralized and digitalized. Although some aspects of this journey cannot be foreseen with certainty, the IESO is resolute in our commitment to support Ontario's energy transition – leading change when required, but also facilitating our partners' leadership.

In responding to sector transformation, the IESO refined and recalibrated its five-year corporate strategy in early 2022. This business plan is anchored in our refreshed strategy, and adds more specificity and detail to demonstrate how we plan to deliver value for Ontarians in the coming years.

IESO Corporate Strategy at a Glance



Drive & Guide the Sector's Future

1.1 Strengthen Stakeholder and Indigenous Communities Engagement & Relationships via Purposeful, Transparent Outreach

1.2 Identify, Anticipate and Respond to Changes in Customer Choice and Policy

1.3 Advise on and Actively Participate in Dialogue on the Configuration of the Future-State Sustainable Energy System



Ensure System Reliability while Supporting Cost-Effectiveness

2.1 Renew the Real-Time Markets to Advance Energy Transformation

2.2 Adapt the IESO's Short- and Long-term Planning to Meet Evolving System Needs

2.3 Cost-Effectively Acquire Services to Maintain Reliability in the Evolving Sector

2.4 Champion Cyber Security, Situational Awareness and Best Practices within the Sector



Drive Business Transformation

3.1 Define and Enhance our Desired Culture and Employee Experience

3.2 Identify and Build Next-Generation Skills and Competencies

3.3 Evolve the IESO's Business Processes, Technologies and Tools

Drive and Guide the Sector's Future

We will drive and guide the sector's future by strengthening relationships with stakeholders and Indigenous communities and effectively responding to changes in customer choice and policy, while acting as an advisor and participant in discussions on how to create a sustainable, future-state energy system.

Strengthen stakeholder and Indigenous community engagement via purposeful, transparent outreach

The essential link connecting all of the IESO's current and future activities is engagement. This includes traditional sector stakeholders, as well as a vast and varied array of other parties who influence our planning and decisions, including Indigenous communities and organizations, business and industry leaders, trade associations, academic institutions and various levels of government. Each group has a unique role to play in the system, with its own specific needs, interests and priorities.

At all times the IESO must work to understand the nature of these forces driving transformation and make informed decisions that strike an appropriate balance. In planning for the future, we must carefully weigh diverse interests and plot a course that considers the interplay among them.

To do so requires honest and open dialogue with the parties affected by our decisions. Given the scope and impact of our mandate, we must work closely with a large number of affected interests, often with competing priorities and varying perspectives. For this reason, engagement activities are absolutely essential to informing the IESO's work.

With every passing year, more voices are joining the energy conversation. Through our engagement processes, we strive to make balanced decisions – decisions that are effective and appropriate, and that will stand the test of time. Over the next five years, we will continue to engage in a targeted and transparent manner, consulting and collaborating with different groups through thoughtful means and mechanisms.

Our engagement with Indigenous communities and organizations, for example, is deepening. Our work in this area is focused on powering change – and changing lives.

Now more than ever before, many Indigenous leaders across Ontario are pursuing projects that support greater energy independence and provide new opportunities to create local revenue and jobs. By developing generation and storage systems, becoming equity partners and leaders in major infrastructure projects, prioritizing energy efficiency as a way to demonstrate environmental stewardship, and engaging in important conversations about system planning, Indigenous communities are seeking greater autonomy and becoming catalysts for change.

The IESO is proud to stand beside them on this journey to greater self-determination. While there is still work to be done, developing Indigenous capacity is an important step towards a longer-term goal of achieving economic reconciliation and driving fair, equitable and inclusive participation in the energy sector.

As our electricity system becomes more decentralized, with more choice at the consumer and community level, the IESO is also strengthening its engagement with municipalities. These efforts will ensure municipal input is integrated into IESO decision making, and that municipalities are aware of opportunities available to them to use electricity to achieve economic development and sustainability goals.

Given the scope and volume of new infrastructure that will be required to ensure the province's capacity needs are met, as are the energy needs that emerge later, the IESO will continue to work with transmitters, distributors, generators, consumers, municipalities and Indigenous communities to ensure all voices are heard and all perspectives are considered.

Identify, anticipate and respond to changes in customer choice and policy

Consumer preferences and choices are some of the key drivers behind the energy transition that is underway. As our reliance on electricity increases through economic growth and the transition to non-emitting energy sources, the IESO is supporting this shift while maintaining reliability and affordability.

As a result, our development activities are focused on meeting consumer demand while respecting customer preferences, including new supply options to meet our growing needs. This includes testing concepts such as residential microgrids, local energy markets, aggregated electric vehicle charging solutions, strategic energy management and artificial intelligence, to name a few.

In the meantime, we are accelerating our efforts to integrate distributed energy resources into Ontario's electricity grid and market. These small-scale community-based resources have the potential to deliver flexible and affordable solutions to local supply issues while also meeting regional and provincial needs.

We will continue to prioritize energy efficiency, the cheapest and most sustainable resource available. The IESO's Save on Energy programs have reached homes and businesses in all sectors across Ontario, saving enough energy over the last decade to power 1.7 million homes for a year. Looking ahead, conservation and demand management will play a growing role in meeting our reliability needs with targeted programs that help address provincial and local reliability concerns.

Advise on and actively participate in dialogue on the configuration of the future-state sustainable energy system

Ontario's energy future will be shaped by the conversations and insights shared through our engagement framework. What our electricity system looks like in the years to come will be influenced by our sector's ability to collaborate and contribute to an understanding of what is needed to evolve the system further.

We are actively working to integrate emerging technologies and enable new resources to participate in the IESO markets. Pairing energy storage with wind or solar generation can improve operational efficiency and help meet the province's emerging electricity needs. For this reason, the integration of hybrid storage/generation resources has been designated a priority project within the IESO's Enabling Resources initiative.

Through active engagement with stakeholders and communities, we have already made great strides, as we build a participation model for implementation. We are also working with sector partners to reduce the barriers to storage resources and evolve the relevant policies, rules, processes and tools to better enable the integration of storage resources within the current structure of our market. Enabling more resources to participate in our markets will increase competition, drive down costs, and provide sustainable options.

Looking ahead, we will strive to support the transformation of Ontario's electricity system by driving and guiding the future of the sector. While at times it is best to lead from the front, charting a path for others to follow, it is also important to create opportunities for others to lead and pave the way when appropriate.

While efforts to reduce emissions across all sectors continue to accelerate, the coming decade will see a rapidly-changing electricity landscape in Ontario. As the first jurisdiction in North America to completely eliminate coal-fired electricity generation, today, Ontario's electricity system is among the cleanest in the world, accounting for less than three per cent of the province's GHG emissions.

The IESO has been engaging with stakeholders, technical experts and others to develop a view of Ontario's decarbonized future. Our Pathways to Decarbonization project provides a focus for concrete conversations about how to eliminate greenhouse gas (GHG) emissions from our system while balancing the need to maintain reliability as other sectors of the economy also decarbonize through electrification.

The move towards greater decarbonization is driving Ontario residents, businesses, institutions and communities to seek new opportunities to further reduce GHG emissions. A growing number of consumers are looking for ways to reduce their carbon footprint by investing in technologies that include electric vehicles, heat pumps, induction stoves, smart thermostats and other devices.

Many industrial and commercial customers are exploring ways to electrify their operations and reduce their reliance on natural gas and other fossil fuels, not only to achieve cost savings but also to meet environmental, social and governance-related objectives. At the same time, a number of municipalities across Ontario have established their own emission reduction targets. Many are implementing major energy-efficiency projects and testing electric transit systems as part of their own climate-change mitigation strategies.

The IESO will continue to share its expertise as part of this dialogue, encouraging a common understanding of the issues at hand and bringing a variety of perspectives to the table. Given our role as system integrator, we must ensure all voices are heard and all ideas are considered. Plotting a viable, sustainable and financially responsible course for Ontario's energy future is a shared responsibility. The IESO will remain steadfast in our efforts to bring the right parties together to explore options to meet changing needs and priorities.

Ensure System Reliability While Supporting Cost-Effectiveness

To ensure system reliability while supporting cost effectiveness, we will transform the real-time markets and adapt our planning processes, cost-effectively acquire services and champion cybersecurity.

Renew the real-time markets to advance energy transformation

As the landscape has changed, so too have our markets. The opening of the wholesale market in 2002 introduced an important new force: competition. By establishing a model where electricity suppliers compete to meet the province's electricity needs, the IESO has ensured Ontarians benefit from a more dynamic and cost-effective system.

Competition is a thread that connects many of the IESO's activities – and is expected to play an even greater role in future operations. The IESO's Market Renewal Program (MRP) is introducing fundamental reforms to the province's electricity markets to improve how we supply, schedule and price electricity to meet Ontario's future needs at the lowest cost.

The market of the future must also accommodate a range of new resource types, often with different strengths and operating characteristics than our existing fleet. Given the ongoing transformation of the system, the market must be flexible enough to support the integration of new sources of supply, accommodate changing policy imperatives and consumer preferences, stimulate investments in new supply as required, and deliver the most economically efficient outcomes. Market Renewal is building the foundation to enable our future needs, decarbonization goals, demand-side participation and new innovations entering the market.

Beyond the wholesale market, competition is expected to dominate other aspects of our business in the years to come, including the procurement of existing and new resources to meet Ontario's rapidly increasing demand for electricity. We are securing resources, testing new integration models and re-examining our systems and processes to reduce barriers to entry to ensure we derive the greatest value from new and emerging technologies.

This essential work will play out over several years, resulting in a system that is more flexible, resilient and diversified. In addition to meeting the IESO's operational requirements, the system must satisfy the needs of ratepayers and communities, as well as asset owners and investors.

In lockstep with the planned implementation of MRP, we are also making great progress on a multi-year initiative to replace our legacy settlement systems to ensure they can support the complex needs of the project. Settling the market is a critical function that requires sophisticated software. Over $22 billion in transactions occur each year through IESO's administered markets and programs so it is imperative that these transactions be settled accurately.

We will continue to take the necessary steps to ensure reliability by upgrading and replacing core applications, infrastructure and cybersecurity tools. For example, core projects include a refresh of the Transmission Rights Auction platform and the completion of the Supervisory Control and Data Acquisition (SCADA) / Energy Management System (EMS) upgrade. We are also investing in a Market Analysis and Simulation Toolset, a tool to monitor, correct, improve or alter market design or operations over the multiple timeframes once MRP goes live.

Adapt short- and long-term planning to meet evolving system needs

One operational challenge the IESO must manage is that electricity needs are not static. Rather, they are subject to a broad range of forces and variables. The dynamic nature of Ontario's electricity requirements means the IESO must take a flexible and responsive approach to planning the system. We must have the ability to identify, react, and adapt to changing realities.

When it comes to electricity planning, understanding what's important to consumers, communities and businesses at the regional level is critical. Every region of the province has unique characteristics and energy needs, which the IESO must understand, consider and plan for.

Over the next three years, we will continue to adapt our short- and long-term planning processes to meet evolving system needs – not just for the province as a whole, but for its many regions and individual communities. We will identify system needs and opportunities, monitor evolving technologies and supply options, and effectively plan transmission so that electricity is available where and when it is needed. To achieve these objectives, we will update our demand forecasting tools and our energy modelling system to ensure we have access to state-of-the-art technologies.

We are also taking steps to improve how we identify and assess distributed energy resources and other non-wires alternatives as these technologies will undoubtedly become more important as Ontario transitions to a cleaner energy supply mix. There will, however, continue to be situations when transmission solutions (poles, wires and stations) will be the only viable option.

We will focus on increasing the transparency of our transmission planning processes to ensure all affected stakeholders, communities, utilities, residents and businesses know what we are contemplating – and why. Every region has its own specific needs and interests so providing opportunities to gain insight from stakeholders and communities is also of paramount importance to inform our decision-making. To ensure electricity infrastructure gets built in a timely manner, we need all of our partners to understand the big picture and the need to expand the system.

By working closely with our partners, we will proactively identify where in the province new, large customers are likely to connect and then develop transmission plans to supply those sites. This foundational work is critical to enable economic development and ensure the necessary supply chains exist to support the energy transition.

To meet future system needs, the IESO will be recommending a relatively large number of transmission projects in the coming years. Transmission projects can take at least seven to 10 years to build, and for reliability purposes it is imperative that these projects be completed on time. For this reason, we will put more emphasis on monitoring the implementation of our plans, understanding any potential implementation risks, and preparing to take action to ensure long-term reliability, if needed.

Cost-effectively acquire services to maintain reliability in the evolving sector

The IESO has worked with sector stakeholders to develop a Resource Adequacy Framework to address evolving reliability needs in a cost-effective and flexible manner while balancing ratepayer and supplier risk.

We remain committed to the using competitive mechanisms to meet Ontario's resource adequacy needs and are working with stakeholders, communities and others to deliver on the Resource Adequacy Framework.

To facilitate competition and provide business planning certainty, our efforts have been structured around three timeframes: short, medium and long-term. In the short term, capacity auctions will be the primary mechanism to meet needs, while existing resources capable of expansions or upgrades are the focus of our medium-term procurements. For new projects with longer lead times, we will conduct longer term procurements to respect developers' need for certainty and a reasonable return on their investments.

In addition to procuring more capacity from existing and new resources, the IESO is also actively exploring the requirements to fully integrate these assets into grid operations and leverage the critical services they can provide – including, most importantly, energy.

Champion cybersecurity, situational awareness and best practices within the sector

Protecting the IESO grid against threats and vulnerabilities remains a high priority, both in the physical and cyber realms. Cyberattacks are becoming more common and more complex with every passing year. For this reason, the IESO continues to work closely with sector partners to share information and deepen situational awareness. The safe and reliable operation of Ontario's power system is built upon a large, decentralized supply chain – and we are already taking steps to reinforce the weakest links.

Given the rate at which cyber risks are increasing, this work will continue for the foreseeable future. Ransomware, malware, social engineering and phishing are the most common ways that bad actors try to access the grid – but this is not unique to Ontario. In fact, it's a global phenomenon and a broadly shared concern. We will remain vigilant and continue to collaborate with experts from around the world to identify, mitigate and minimize the collective risks to reliability.

In 2019, the IESO became the first system operator in North America to be accountable for providing cybersecurity-related services to the broader electricity sector. Lighthouse, the cornerstone of our cyber offerings, provides a near real-time view into threats and incidents that can impact the power grid. Designed to improve the security and resilience of the system, this detection, assessment and information-sharing service is the result of a one-of-a-kind partnership with the Canadian Centre for Cyber Security, a trusted federal source of cybersecurity information, advice and guidance that builds on the IESO's existing leadership and capabilities.

We will continue to expand the reach and effectiveness of our flagship Lighthouse program to ensure we enroll as many members as possible. A holistic view and understanding of market participants' cybersecurity postures and program objectives is required to develop an informed and coordinated approach to cyber resilience for Ontario's electricity sector.

As cybersecurity events, and ransomware attacks in particular, continue to increase across the sector, the IESO is also focused on bolstering its cyber incident response capability. These initiatives include developing cyber incident response playbooks and conducting regular tabletop exercises to practice response execution in an effort to reduce the potential impact and accelerate resolution timelines.

Drive Business Transformation

To drive business transformation, we will evolve our internal processes, technologies and tools, identifying and building next-generation skills and competencies while defining and enhancing the IESO culture and employee experience.

Define and enhance our desired culture and employee experience

The IESO's organizational success is underpinned by our employees. For this reason, we are taking concrete steps to modernize our corporate culture and enhance the employee experience. The IESO is on a journey to establish a more inclusive culture where our people can realize their full potential.

Our vision is to create a sense of belonging, where diverse expertise and perspectives are valued. We must operate in a fair and consistent manner, make employees feel safe challenging the status quo, and ensure corporate values are reflected in the attitudes and behaviours of our workforce. IESO employees have a strong sense of purpose, and we are making the necessary investments in our people and our workplace to enable them to deliver results that support it.

We have already taken a number of actions, with more to follow. The IESO is working to support its employees by promoting a clear understanding of our purpose, strategic priorities, and key activities. Leaders must create an environment of inclusivity, enhance their team's connection to support IESO's priorities and encourage diverse perspectives while investing in each other's success.

This evolution requires ongoing organizational focus and change in a number of areas. We must fully align our workforce to common goals and priorities. This shared understanding will help to build a united, cohesive team with a common commitment to achieving our goals.

We are also proceeding with an organizational alignment review that will be implemented in 2023. This review will ensure we have the right organizational structure in place to provide clarity for decision-making through well-defined leadership roles with clear accountabilities. This will support the delivery of our strategy and mandate moving forward.

The review will enable the IESO to identify existing strengths and opportunities for enhancements to our current organizational structure; align roles and accountabilities to the refreshed corporate strategy; clarify accountabilities and decision-making both vertically and horizontally; empower leaders within their scope of authority; and better enable our leaders to successfully guide their teams in implementing the strategic plan and delivering our core mandate.

Before the pandemic, we also launched a program to assess our broader space needs and explore the benefits offered by co-locating more employees at a single location. These benefits included advancing our culture, offering employees more flexibility and choice in how and where they work within the office, and optimizing our real estate footprint with savings realized outside of this business plan's time horizon. While the strategies to achieve our goals have evolved over time, many of our objectives remain the same: a more flexible, inviting and cost-effective workspace that responds to emerging workplace trends and employee feedback, supporting a culture based on teamwork and collaboration, and an improved employee experience overall.

Although the pandemic has provided an opportunity for us to reconsider and reevaluate our space needs, especially in the context of a proposed hybrid work model, we will continue to prioritize employee wellbeing, business productivity and cost containment.

Identify and build next-generation skills and competencies

Ensuring our employees have the skills they need to excel in a changing environment is a high priority. Learning needs change over the course of every career. For this reason, we offer learning and development opportunities for staff at different points in the employee lifecycle. Although some training content is tailored to meet the needs of employees at specific levels in the organization, we firmly believe leadership can be found across the IESO. It is a skill we plan to nurture, as all employees play a key role in helping the IESO achieve its strategic objectives.

Internal capacity building will be even more critical in the years to come. By making strategic investments in learning and development, we are taking steps towards aligning program offerings with corporate priorities and employee interests, which is essential to driving engagement, commitment and loyalty.

We are proactively working to build the necessary capabilities for the future to deliver on our mandate. For example, forecasting demand and ensuring resource availability is a complex task that requires expertise across the organization, including planning, operations, contract management, information technology and market development, among others.

We are also developing plans to attract, engage and retain top-level talent in certain key areas, including cybersecurity, data science, artificial intelligence and machine learning, stakeholder and community relations, contract management, and economics We will also focus to a greater degree on succession planning and strengthening inclusive leadership capabilities.

As is the case with many of our sector partners, the IESO is experiencing a demographic shift with the planned retirement of some long-term employees. We are actively recruiting from top academic institutions to attract staff with the optimal combination of skills, experience and passion to drive the organization forward.

To deliver the best results, employees need to be future-oriented, solutions-driven and capable of responding positively and effectively to changes in the environment. They also need the right tools and technologies to do their work.

Evolve business processes, technologies and tools

Driving business transformation involves optimizing our workforce as well as the systems and processes that support them. As with every aspect of Ontario's electricity sector, the changes required to make this happen are significant and wide reaching. Today, we are making the necessary investments to facilitate this transformation and deliver long-term value to residents, communities, businesses and institutions across Ontario.

Complex information technology (IT) programs and tools enable us to perform essential tasks that include forecasting demand, dispatching resources and monitoring the grid for cyber threats. After years of deferring investments in a risk-informed way, many of the IESO's IT systems require

renewal as they approach their end of life. Some of these upgrades will be made to control room systems to support the integration of emerging resources, and to improve situational awareness. In the coming years, we will continue to update or replace many of these key IT systems that help us maintain the reliability of the grid.

Good decisions require good data. Given our central role in managing the power system and the scope of our IT tools and systems, the IESO has access to a wealth of operational electricity data stretching back to the opening of Ontario's electricity market in 2002. When fully utilized, this data can provide unique insights into the complex inner-workings of electricity production, usage, planning, forecasting and much more.

Earlier this decade, the IESO embarked on a program of work to evolve our data and analytics maturity level and capabilities. By developing a data strategy and enterprise data catalogue, the IESO is treating organizational data as an invaluable business asset. We continue our work to leverage this data to identify additional market efficiencies, support reliable grid operations and improve our risk management practices.

We are also evolving and enhancing many of the IT systems that support our operations staff to ensure they have maximum visibility into different grid assets.

Financial Overview

The 2023-2025 Business Plan provides an overview of the resources required to maintain the high levels of performance necessary for the IESO to deliver on its core responsibilities, as well as deliver on the first three years of a refreshed strategy, committed to helping drive and guide a transition to ensure a reliable, affordable and sustainable energy future.

The IESO is moving forward on key initiatives that are critical to maintaining its core operations and to support the significant growth in the industrial, mining and agricultural sectors, as well as major expansion in transportation electrification, which will collectively drive higher electricity demand than Ontario has seen in many years; demand is expected to increase by nearly two per cent per year during the next 10 years. These demand increases are being compounded by nuclear retirements and refurbishments as well as the expiration of a large number of generator contracts, which impacts available supply. Energy needs are emerging as early as 2025.

To achieve this outcome, the IESO is proposing increases to its revenue requirement of 5.8%, 4.8%, and 5.2% over the three year planning period. The rapid increase in the interest rate is forecasted to add $5.4 million of surplus through interest income to the IESO in 2022 by year-end. This rate of increase was not budgeted thus the surplus is deemed an uncontrollable variance that is excluded from the percentage year over year increase between 2022 and 2023 funding requirements. Over the 2023-2025 planning period, for the average residential electricity bill, this translates to an 8.3 cents per month increase. The IESO has taken steps to manage our exposure to macroeconomic trends and will continue to do so in support of value for ratepayers. The IESO has and will continue to carefully review all expenditures and find efficiencies, where possible, to minimize the impact to ratepayers of Ontario while we invest to support the significant transformation of the sector.

We have identified and leveraged efficiencies in several areas. As noted above, we anticipate a large increase in new generation and other contracts over the next three years and have overhauled some of our contract management and associated registration activities. By introducing contract procurement and registration fees that are paid by the project proponents, IESO expenses are offset and impacts to Ontario ratepayers are reduced. At the same time, further development of systems to track these contracts (Beacon system), automation of contract settlements and energy efficiency processes to streamline approvals have yielded operational efficiencies. Furthermore, we continue to realize efficiencies by examining our long-term office space needs.

In the 2023-2025 Business Plan, the IESO is proposing to:

- Continue work started in 2022 under Resource and Transmission Adequacy and Enabling Resources, furthering incremental investments to secure additional supply and expansions needed to address electricity needs emerging and the unprecedented transformation of the electricity system over the next decade.
- Deliver on government initiative work related to Class B and Interruptible rate pilots, potential program to provide new contracts for existing small hydroelectric generation facilities, enhanced energy efficiency conservation and demand management programs, along with other smaller initiatives.

- Complete the $233 million Market Renewal Program (MRP) investment, at which time the new market will begin to generate significant ratepayer savings building on the benefits that the market has delivered to consumers over the past 20 years. The program investment will be amortized over a 20-year period. The new market will introduce new features and tools that require additional resources for market operations, monitoring and ongoing maintenance and support. As such, the business plan includes resources for additional staff, technical consultants and support & maintenance to operate the renewed market.
- Strengthen IESO's preparedness to support Ontario's electricity transformation through enhancing cybersecurity posture, reinforcing the resilience and integrity of the electricity grid, sustaining our critical IT systems and enabling the grid transformation program. It will also include strengthening stakeholder and community connections, and continuing to build out workforce capacity and capabilities to promote a high-performing organization.

These investments are necessary to enable the IESO to play a critical role in driving and guiding the energy transformation underway.

The 2022 forecast is below approved budget due to significantly higher interest income, increased electricity demand thus higher revenue and lower expenses driven by project and staff hiring delays. The 2023 higher expenses are driven by incremental initiatives and amortization impacts of assets placed into service in late 2022. In 2024 and 2025, expenses are impacted by transition to post MRP integration functions and services including amortization impacts, and further investments most notably in initiatives to ensure resource acquisition to meet system needs by 2026. The 2023-2025 business plan has significantly higher interest income and revenue from registration fees used to offset the revenue requirement.

After rigorous review, staffing levels will increase in 2023 as a number of strategic positions are added to support key initiatives (including the MRP). For 2023, the IESO anticipates an average of 914 full-time equivalent employees to deliver on core electricity system responsibilities and initiatives, as well as to support the MRP. Staffing levels will remain relatively flat in 2024 as the MRP begins to wind-down, with certain staff returning to core functions, concluding the transition in 2025 when the average full-time equivalent number of employees will be reduced to 900.

As part of its mandate, the IESO operates several programs that are funded from other sources and are not included in this business plan, including: the smart metering entity, market rule enforcement and education, and energy-efficiency programs.

The IESO has approval from the Ontario Energy Board to maintain an operating reserve of $10 million to manage cost or revenue variances from budgets caused by changes to the external environment that impact the IESO and may not be within its control or reasonably foreseeable. This practice is adopted by similar sector organizations. As the IESO enters into its first three-year business plan, and given the complexity and uncertainty around the transformation of the sector, there is potential for additional unplanned needs that may be material in scope. The IESO will be recommending to the OEB an increase to the operating reserve to a balance of $15 million, to be funded through its forecasted 2022 surplus, to address these potential needs.

Detailed Financials

The following table outlines 2023-2025 business plan operating revenues and expenses:

Pro Forma Statement of Operations
For the Year Ended December 31
(in Millions of Canadian Dollars)

($ Millions)	**2022 Budget**	**2022 Forecast**	**2023 Budget**	**2024 Budget**	**2025 Budget**
Revenue					
IESO Usage Fee	201.5	204.1	208.4	218.4	229.7
Expenses					
Baseline Expenses	172.8	171.4	175.4	181.4	187.7
Resource and Transmission Adequacy	1.7	1.4	6.0	8.8	7.3
Enabling Resources	0.4	0.6	0.8	0.9	0.9
Pathway to Decarbonization	1.3	0.9	-	-	-
Other Government Priorities	4.6	4.3	2.9	2.5	2.5
MRP – ongoing operation of new functions	0.5	0.2	1.9	3.0	4.2
Cybersecurity	-	0.9	1.6	1.6	2.1
Strengthening Engagement	-	-	0.7	1.1	1.6
Culture, Employees and Capabilities	-	-	0.8	0.8	1.0
Sustaining Technology, Evolving Processes and Tools	-	-	1.9	2.3	2.2
Operating Expenses sub-total	181.3	179.7	192.0	202.2	209.4
Amortization	20.0	18.5	23.1	22.0	27.0
Net Interest	(5.0)	(10.4)	(11.5)	(9.7)	(9.2)
Registration Fee	-	(0.8)	(0.5)	(0.5)	-
Market Renewal Program	5.2	4.3	5.3	4.4	2.5
Total Expenses	**201.5**	**191.3**	**208.4**	**218.4**	**229.7**
Uncontrollable Interest Variance		*5.4*			
Adjusted Total Expenses	*201.5*	*196.7*	*208.4*	*218.4*	*229.7*
Year over year variance		*-*	*5.8%*	*4.8%*	*5.2%*
Operating Surplus/(Deficit)	**-**	**12.8**	**-**	**-**	**-**
Accumulated Operating Surplus	8.7	15.0	15.0	15.0	15.0
Potential Rebate to Market Participants	-	6.5	-	-	-

Capital

As with previous years, the business planning process establishes an appropriate capital envelope for core operating initiatives over the business planning timeframe, with commitments approved individually, on an ongoing basis.

There will be increased capital investments over the period of the business plan in order to make significant investments in the IESO's facilities ($30 million) and backup operating and data centres

($10.4 million) that are required to maintain our facilities, drive business transformation and maintain reliable system and business operations.

In addition to these major investments, a number of other capital projects will be undertaken to fulfill our mandate and advance our refreshed strategy. Details for the larger initiatives are outlined in Appendix 3.

The Market Renewal Program capital costs for 2023-2025 in the table below are the latest estimate of program spending and are in alignment with the revised schedule and in-service date approved by the IESO board.

Project details and associated descriptions are included in Appendix 3.

Capital ($ Millions)	**2022 Budget**	**2022 Forecast**	**2023 Budget**	**2024 Budget**	**2025 Budget**
Core Operations Initiatives	30.0	30.0	23.0	28.6	30.6
Space Needs Program & Facility Investment	-	-	7.0	10.0	13.0
Back Up Operating and Data Centre Relocation	-	-	5.0	5.0	-
Market Renewal Program	41.2	37.1	51.0	32.3	14.6
Total Capital Envelope	**71.2**	**67.1**	**86.0**	**75.9**	**58.2**

Full Time Equivalent (FTE) Staffing

In 2023, the average core operations FTEs of 805 is higher than 2022 levels by 91 FTEs due to delayed hiring of resources in 2022 and additional resources to support the IESO's initiatives on-boarded throughout 2023. Core operations FTE levels in 2024 increase to 838, mainly due to ramp-up of staff required to support additional energy procurements and prepare for the new market functions/services. In 2025, as Market Renewal Program (MRP) is completed, some resources will be returning to core operations as others conclude their temporary employments, thus the increase to 856 FTEs.

Staffing levels required to support the MRP implementation will reach 109 FTE in 2023, and are expected to decrease slightly in 2024 as the project moves to operations testing activities. In 2025 some staff are retained to provide market participants and internal staff with training, complete internal documentation, make tool changes post go-live and ensure that a framework is in place to measure the benefits.

Average FTEs

Full Time Equivalents (FTEs)	**2022 Budget**	**2022 Forecast**	**2023 Budget**	**2024 Budget**	**2025 Budget**
Core Operations	730	714	805	838	856
Market Renewal Program	97	92	109	88	44
Total FTEs	**827**	**806**	**914**	**926**	**900**

Market Renewal Financials

As of 2021, the Market Renewal Program (MRP) has entered the final phase of the initiative: implementation. This phase of work will ensure both the IESO and market participants are prepared for the launch of the renewed market.

Market Renewal Program Baseline Schedule, Budget Update and Funding

The IESO has been working with vendors and stakeholders to refine and translate the design into system requirements and rules needed to finalize the delivery schedule for MRP. In August 2022, the IESO Board approved revised program funding and a refreshed schedule, including an in-service date of May 2025. The updated cost estimate for the delivery of MRP is $233 million, including contingency, and is outweighed by the significant ratepayer benefits from project implementation. A recent review of the MRP business case determined the renewed market will deliver substantial net financial benefits of over $700 million to Ontario consumers over the first 10 years of operation.

The capital activities for MRP include solution development deliverables and testing, which requires contracting external vendors as well as broad support from across the organization, including a significant complement of IT resources. MRP activities funded through operating costs include the development of market rules and related stakeholder activities, change management planning and coordination, and updates to internal and external manuals.

In 2025, the IESO will require funding post go-live to deliver market participant support and training, complete internal document updates, and start project closure activities while maintaining a capital budget for additional vendor support and internal IT costs for tool changes identified after the in-service date.

The annual MRP project costs from 2023-2025 are consistent with the Board-approved refreshed schedule and funding.

Appendix 1 – IESO Performance Management – Measures and Targets

The IESO's performance management program provides an important level of oversight for the organization and its stakeholders, and helps to ensure accountability and course correction, as needed.

Measures and targets have been revised to align with the IESO's refreshed strategy and the 2023-2025 Business Plan. Since the strategy update this spring, Directors and ELT members have been engaged in an iterative process to contribute refreshed measures and identify annual targets. This set of measures is intended to help improve engagement and provide clear identification with how work efforts contribute to the IESO's overall strategy success.

Strategic Alignment		Measure	Target			Measure Weight
			2023	2024	2025	
Outcomes	• Drive and guide the evolution of the system to ensure long-term reliability • Maintain affordability via competition and other mechanisms • Effectively respond to changes in policy and customer choices	1. Market Renewal Program delivery: Total actual schedule complete percentage is within planned completion	80%	90%	100%	20%
		2. Maintaining Resource Adequacy: plans in place to ensure that resource adequacy reliability standards are met for the next 5 years	100%	100%	100%	10%
		3. Resource Adequacy procurement: number of supply offers in open and competitive mechanisms exceed the target capacity	20%	22%	24%	10%
		4. Enabling Resources Program delivery: Percentage complete according to program plan	33%	44%	65%	10%

Strategic Alignment		Measure	Target			Measure Weight
			2023	2024	2025	
Enablers	• Evolve the IESO's culture enabled by people, tools, and processes to promote a high-performing organization • Effectively tell the IESO's story to strengthen stakeholder and community connections	5. Employee pulse survey results for specific annual engagement areas of focus 6. Effectiveness of stakeholder engagement actions through positive survey results (within -2% tolerance range)	4% average increase 80%	4% average increase 81%	4% average increase 82%	15% 15%
Key Risk	• Maintain vigilance on cyber security threats to the IESO and the system, and adapt as required	7. Cyber threat intelligence technology implementation 8. Phishing Metrics Trend 9. Determine pathway for assessment of appropriate regulatory instrument for system cyber risk mitigation*	90% <5% Substantial Completion	92% <4% TBD	94% <3% TBD	10% 5% 5%

* 2023 is to develop a measure. Execution against cyber risk mitigation measure will occur in 2024-2025.

Appendix 2 – Enterprise Risk Management

At the IESO, risk management is an integrated discipline that supports informed decision-making throughout the organization. We recognize the pivotal role it plays in balancing strategic planning with business execution and compliance. This facilitates informed decision-making and a conscious evaluation of the upside opportunity and downside aspect of risk.

Our integrated approach to managing risk recognizes the need for clear, timely direction and support from our Board of Directors and senior, business unit and functional management.
Our starting point for managing risk is our strategic planning process, where key risks are identified from the internal and external threats and opportunities. Risks and opportunities are identified by observing, analyzing and anticipating trends along with macroeconomic, industry-specific, regional and local developments. Senior management assesses the risks to achieving our strategic objectives, and incorporates measures into corporate and operating plans to mitigate these risks if they exceed our target risk levels.

The IESO uses a risk management ranking methodology to assess the key risks specific to our achieving our strategic and business plan objectives. Our top strategic risks, aligned with the IESO's strategic objectives and their associated residual risk assessment, are as follows:

Risk	Risk Assessment: Critical Mitigating Actions
Material undersupply of energy at a provincial and regional level Medium-term timelines are becoming more critical within our strategic planning time horizon. As the province's reliability coordinator, the IESO must comply with, oversee and enforce reliability standards and processes that are set by several regulatory bodies within and outside of Ontario. The concern about undersupply arises from not having sufficient time to address the long lead times needed to build infrastructure or the ability to respond to changes in demand.	• Advancing initiatives under the Resource Adequacy framework to design and execute procurements to acquire committed and contracted resources • Expanding transmission planning programs to ensure new capacity can be connected • Enhancing planning and forecasting tools for medium- and long-term energy supply • Delivering annual acquisition report and annual planning outlook to provide stakeholders with much-needed insights into opportunities for existing and new resources • Building alignment with government on how potential barriers to procurements and challenges to new facility development will be overcome

Risk	Risk Assessment: Critical Mitigating Actions
IESO actions to identify and address supply shortfalls not seen as credible by the stakeholder community The stakeholder community authorizes the IESO to take action and provide the resources necessary to create value towards the achievement of cost-effective reliability. Not having credibility with the stakeholder community can impede the IESO's ability to deliver results.	• Advancing initiatives under the Resource Adequacy Framework to design and execute procurements to acquire new supply • Consistently delivering on the Enabling Resources Program to introduce new grid-connected resources • Developing and executing a purposeful approach to stakeholder and community engagement • Enhancing external information sharing and reporting processes
Risk	**Risk Assessment: High** **Mitigating Actions**
The IESO's information technology systems and data are disrupted by cybersecurity threats Cyber attacks on the IESO's information technology systems and data could be highly disruptive to reliability, business systems and data protection through exploiting vulnerabilities across people, processes, and technology. These threats from domestic and foreign threat actors may arise from malicious intent, financial motivation, ignorance and/or complacency. This risk needs to be monitored to protect the business, employees, and safeguard critical data, systems, and facilities from being compromised.	• Promoting a culture of cybersecurity awareness through policies and training • Improving incident response capabilities and communications • Implementing targeted solutions to help better identify and mitigate malicious threat actors from launching a successful attack • Enhancing threat intelligence capabilities and upgrade network architecture, data management and security controls

Risk	Risk Assessment: High Mitigating Actions
Cyberattack impacting non-IESO owned assets required for operating the IESO-controlled grid As cyberattacks targeting critical infrastructure are on the rise, a sector-wide, concerted cyber response is required from government, regulatory bodies, market participants and the IESO to augment response efforts. A holistic view and understanding of market participants' cybersecurity postures and program objectives is required to develop an informed and coordinated approach to cyber resiliency for the Ontario electricity sector.	• Maintain robust reliability practices and contingency plans to respond to significant disruptions • Deliver Lighthouse services under OEB license to promote cyber information sharing and situational awareness across the sector • Conduct sector-wide threat assessments to identify vulnerabilities • Support external activities by developing playbooks and participating in broader groups and forums

Risk	Risk Assessment: High Mitigating Actions
Competitive mechanisms not working as intended impairs the IESO's efficiency mandate The IESO is investing considerable time and resources to renew the wholesale electricity markets and operate the grid to drive reliability outcomes. The IESO's strategic priorities could be impacted if competition and supporting market mechanisms are impaired. If competition does not materialize as expected, the loss of stakeholder confidence could drive an emerging narrative that markets don't work thereby frustrating the IESO's efficiency mandate.	• Design, development and testing of mechanisms as such as Market Power Mitigation under the Market Renewal Program • General Conduct Rule enforcement guidelines • Next phase of resource adequacy initiatives that involve competitive procurements and capacity auction as acquisition mechanisms

Risk	Risk Assessment: High Mitigating Actions
Readiness of our culture, people, processes and tools to rapidly adapt and pivot to address transformation To deliver on the organization's goals and meet the demands of sector transformation, the IESO will need to transform. Meeting the demands of transformation is a complex process involving alignment of leadership, practices and culture. Evolving the maturity of the IESO's culture, people, processes and tools will require some necessary pre- and co-requisite change readiness supports.	• Acquisition of business and grid control tools to support transformation • Resource planning and utilization: roles and accountabilities and workforce planning initiatives • Development of future capability: employee, leadership, technical, and business learning; succession planning • Culture transformation: Equity, diversity and inclusion (ED&I) Annual Plan and employee experience annual areas of focus • Evolve data and information governance practices

Appendix 3 – Capital Spending

Summary of 2023 - 2025 Capital Spending

Change Initiatives/Projects ($ Millions)	2023 Budget	2024 Budget	2025 Budget
Replacement of the Settlement Systems	4.4	0.8	0.1
Data Excellence Program	0.5	0.8	0.5
Wide Area Visualization Environment (WAVE) - Phase 2	0.5	0.3	
Enabling Resources Program	0.3	0.6	3.3
Addressing Market Surveillance Panel (MSP) Recommendations	1.2	0.4	0.5
Dynamic Limits in Real-Time	2.8	0.2	
Enterprise Antivirus Replacement	0.3		
Resource Adequacy Program	1.0	1.2	1.3
Market Analysis and Simulation Toolset (MAST)	0.5	2.4	1.0
Long Term Demand Forecast Tool Replacement	1.0	0.8	
Core Network Refresh	2.0	0.6	
PMU Integration - Phase 3	1.0	1.0	1.0
Space Needs Program	7.0	10.0	13.0
Backup Operating and Data Centres Relocation Project	5.0	5.4	
Meter Data Management System Replacement (MDMS)	0.3	2.0	3.5
Enabling Grid Transformation Program	0.1	1.1	7.0
Lawson Refresh		0.2	1.9
Firewall Refresh	0.2	2.8	
Data Loss Prevention (DLP) Phase 2		1.5	1.0
Windows Infrastructure Refresh	1.9	0.1	
MIM Technical Refresh	1.1		
LogRhythm SIEM Refresh		2.9	0.1
Network WAN Infrastructure		1.6	0.1
Cybectec Refresh		0.9	0.1
Aspen File Server Refresh			2.1
Intrusion Prevention System (IPS) Refresh			1.4
Capital (1 million and above)	**31.1**	**37.6**	**37.9**
Other Initiatives/Projects (Less than a 1 million)	**3.9**	**6.0**	**5.7**
Total Without Market Renewal Program	**35.0**	**43.6**	**43.6**
Market Renewal Program	**51.0**	**32.3**	**14.6**
Total Including Market Renewal Program	**86.0**	**75.9**	**58.2**

2023-2025 Capital Plan Details

Project Name	Project Description
Replacement of the Settlement Systems	In replacing settlement systems that have been in operation since market opening in 2002, this project will address market re-design needs associated with implementation of the Market Renewal Program and enable systems to meet current and future business needs. In 2021, the IESO settled approximately $22B in the IESO-Administered Markets, Ministry of Energy supported programs, and Global Adjustment through the settlement systems.
Data Excellence Program	To help harness the full value of IESO data, this program establishes an evolved data management and analytics framework to support the IESO's complex business needs. Data governance policies and tools (data catalogue), an updated data warehouse strategy and supporting applications for high-value use cases and a centre of excellence for advanced machine learning applications are in the scope of the program roadmap.
Wide Area Visualization Environment (WAVE) - Phase 2	This project will improve situational awareness and maintain ongoing compliance with NERC IRO standards by expanding modelling to neighbouring power systems (NYISO, PJM and Hydro-Quebec), improving the IESO's ability to monitor and respond to real-time conditions that may affect the IESO controlled grid.
Enabling Resources Program	Through the Program the IESO will prioritize and undertake the work to increase the number of resource types (e.g. hybrids, storage) that can participate in the IESO markets to deliver energy, capacity and ancillary services in order to increase options for reliability and competition to drive affordability.
Addressing Market Surveillance Panel (MSP) Recommendations	A portfolio of initiatives to develop, evolve and address inefficiencies in the electricity market in response to observations by the MSP and other stakeholders.
Dynamic Limits in Real-Time	In enabling the continuous assessment of real-time grid conditions, the Dynamic Limits in Real-Time (DLRT) Project will significantly improve the utilization of Ontario's transmission system, resulting in market and system operations efficiencies, and increased system security and resilience.
Enterprise Antivirus Replacement	The current antivirus solution which was commissioned in 2018 has approached end of support by the vendor on the solution lifecycle. The current vendor is moving to a cloud based service offering only, which will not meet the current NERC Critical Infrastructure Protection (CIP) standards. This project will replace the current antivirus solution with a new on-premise solution that will maintain the IESO's security posture and continue to meet the NERC CIP requirements.
Resource Adequacy Program	As part of its commitment to competitive mechanisms to meet Ontario's resource adequacy needs, the IESO is working with stakeholders to implement the Resource Adequacy framework to develop and execute multiple mechanisms, such as the Capacity Auction and Requests for Proposals to acquire products and services needed to maintain reliability cost-effectively.
Market Analysis and Simulation Toolset (MAST)	As the Market Renewal Program (MRP) is introducing wholesale market changes, current tools to monitor, assess and analyze the new market will be insufficient. MAST will deploy a common assessment tool environment that can be utilized in multiple business processes that will monitor, correct, improve or alter market design or operations over the day-ahead, pre-dispatch and real-time periods. The new tools are required after MRP go-live.

Long Term Demand Forecast Tool Replacement	This project will replace the existing Long-Term Demand Forecast tools which have reached end of life and update the end-use load profiles used to develop the long-term forecasts. These tools are essential to support the planning processes that forecast system needs and provide infrastructure investment advice for the next 20 years.
Core Network Refresh	The IESO's Core and Data Centre networks provide the backbone of the IESO's network infrastructure, connecting all systems and locations in a robust and reliable high-performance network. The existing core and data centre infrastructure needs to be refreshed as it is approaching the end of manufacturer support.
PMU Integration - Phase 3	Phasor Measurement Units (PMUs) can continuously deliver high-quality, time synchronized real-time power system data at a high frequency (30-60 samples per second). Obtaining PMU data from across Ontario will improve real-time monitoring of the IESO-controlled grid; obtaining PMU data from other jurisdictions will improve wide-area view; and both will improve the IESO's overall situational awareness. PMUs also provide the IESO the ability to diagnose incidents and to more efficiently comply with several NERC reliability standards. Building on the earlier phases of this work, Phase 3 will integrate PMU data into the IESO's operations support tools and services, as well as live information into the Control Room. The Market Rules to support this change have been implemented and will become enforceable at the end of 2024 to give participants and the IESO sufficient time to implement these changes.
Space Needs Program	IESO owns and leases three office facilities in the Greater Toronto Area. Our primary location in Mississauga, which the IESO owns and operates, was built in 1989 and requires significant investments in its electrical, mechanical and structural systems over the next 4-5 years. Building on the experience from an office pilot project being undertaken in 2022, the results will define the path forward with respect to the IEOS's overall office footprint and the modernization of the workspace. The modernization of the workspace will be critical to meet the needs of today's workforce and supports the attraction and retention of IESO staff
Backup Operating and Data Centres Relocation Project	As part of its system operator mandate, the IESO operates a Backup Operating Centre (BOC) and Backup Data Centre (BDC) to ensure continuous operation of Ontario's power system and IESO's business operations in event of an emergency affecting the power system or IESO's control centre. These facilities are also required in order to comply with North American Electric Reliability Corporation (NERC) reliability and critical infrastructure protection standards. The current BOC and BDC are reaching the end of their current lease terms and no longer meet the evolving needs of the IESO. This project will determine and secure a new location for these two critical facilities and make the necessary investments in order to meet both regulatory compliance and reliability needs.
Meter Data Management System Replacement (MDMS)	The current Meter Data Management solution that supports the IESO settlement processes is currently deployed on an application that cannot be upgraded. The business capabilities that the application supports will be delivered as part of an alternative solution through the Meter Data Management System Replacement project.

Enabling Grid Transformation Program	In conjunction with the PMU Phase 3, Wide Area Visualization - Phase 2 and Dynamic Limits In Real-Time projects, this program will implement new technologies, processes, and more dynamic tools to support the operation of the transforming grid with more diverse resource types and a more complex transmission system. This work is critical to support resource retirements/replacements, meet incremental system demand by adding supply resources to the system, as well as provide future options for de-carbonization.
Lawson Refresh	Lawson Financials, the current financial and accounting application that supports both the Market and Corporate accounts has been used at the IESO since 1998. The last Lawson refresh project was completed in 2020 and is approaching end of life. This project will refresh our current financial system to ensure that it continues to meet our future financial accounting needs with a vendor supported tool.
Firewall Refresh	The existing IESO firewalls which provide access control to critical parts of the network such as the DMZ and internal corporate network are nearing the end of vendor support and need to be upgraded. This project seeks to build on the strengths of the existing security architecture by upgrading the key security controls at the firewall perimeter of IESO's data network and allow the IESO to take advantage of features which are used to reduce the risk of evolving cyber attacks and ensure mitigation of security concerns related to the industry.
Data Loss Prevention (DLP) Phase 2	Data loss prevention (DLP) is an approach that seeks to improve information security and protect business information from data breaches. This project will implement a technological DLP solution that will provide features and benefits in a variety of situations, all of which will allow the IESO to better understand how high-value data is handled within the network and will automate the prevention of data sharing with unauthorized personnel.
Windows Infrastructure Refresh	The current version of Microsoft Windows Server operating system is nearing end-of-life at which time Microsoft no longer provides support for the product, including critical security patches. This project will move us to the latest supported version of the Windows operating system and refresh the underlying hardware.
MIM Technical Refresh	The Market Information Management (MIM) system is the IESO solution that receives Dispatch Information (bids/offers) from Market Participants and is the repository for the results of the Day Ahead Optimization System and Market Information System. This project will update the solution to use supported hardware and supported technology components.
LogRhythm SIEM Refresh	LogRhythm is IESO's Security Information and Event Monitoring (SIEM) solution which monitors security events by gathering log data across all IT connected systems. This project will refresh the LogRhythm solution to provide more computing capacity to accommodate the growth of IESO's IT systems.
Network WAN Infrastructure	The IESO Wide-Area Network (WAN) infrastructure is a collection of networks that communicate with one another between all IESO locations, and with Market Participants through a WAN provider. This project will replace all WAN infrastructure which is reaching end of life.
Cybectec Refresh	The IESO collects over 100,000 telemetry data points every two (2) seconds and pushes that data into IESO's Supervisory Control and Data Acquisition (SCADA) systems. The Cybectec gateways support this critical function. This project will refresh the existing Cybectec gateways that have reached the end of their useful life.

Aspen File Server Refresh	Aspen is IESO's corporate fileserver which stores much of IESO's business information. This project will replace the underlying hardware and software with new hardware and software and migrate data to the new platform.
Intrusion Prevention System (IPS) Refresh	The Intrusion Prevention System (IPS) prevents network security attacks such as brute force attacks, Denial of Service (DoS) attacks and vulnerability exploits. IPS continuously monitors network traffic to detect/prevent against known and unknown vulnerability. This project will refresh the current IPS as it reaches end of life.

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, Ontario M5H 1T1

Phone: 905.403.6900
Toll-free: 1.888.448.7777
E-mail: customer.relations@ieso.ca

ieso.ca

@IESO_Tweets
linkedin.com/company/IESO

Connecting Today.
Powering Tomorrow.

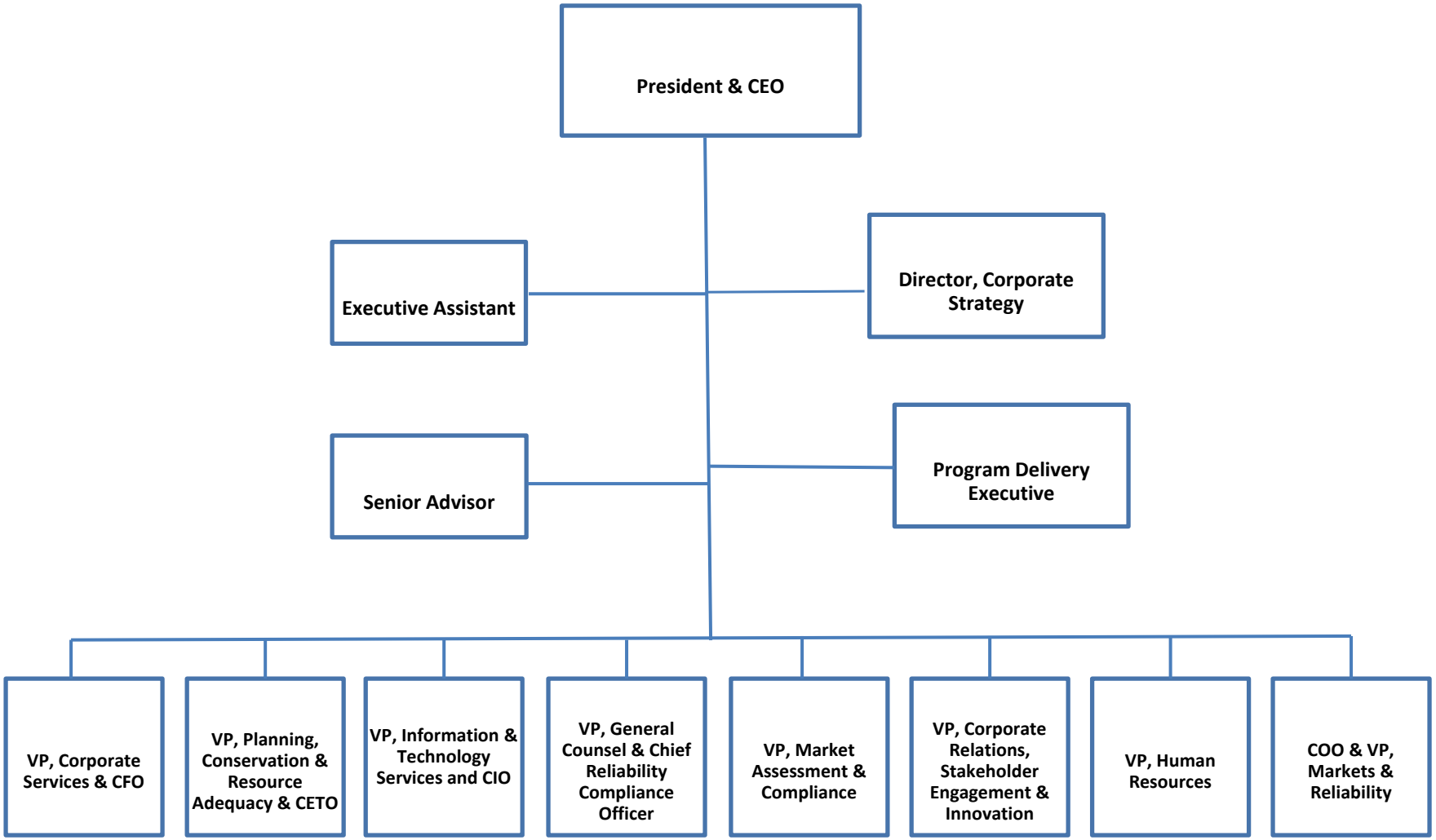
TAB 6

EXHIBIT LIST

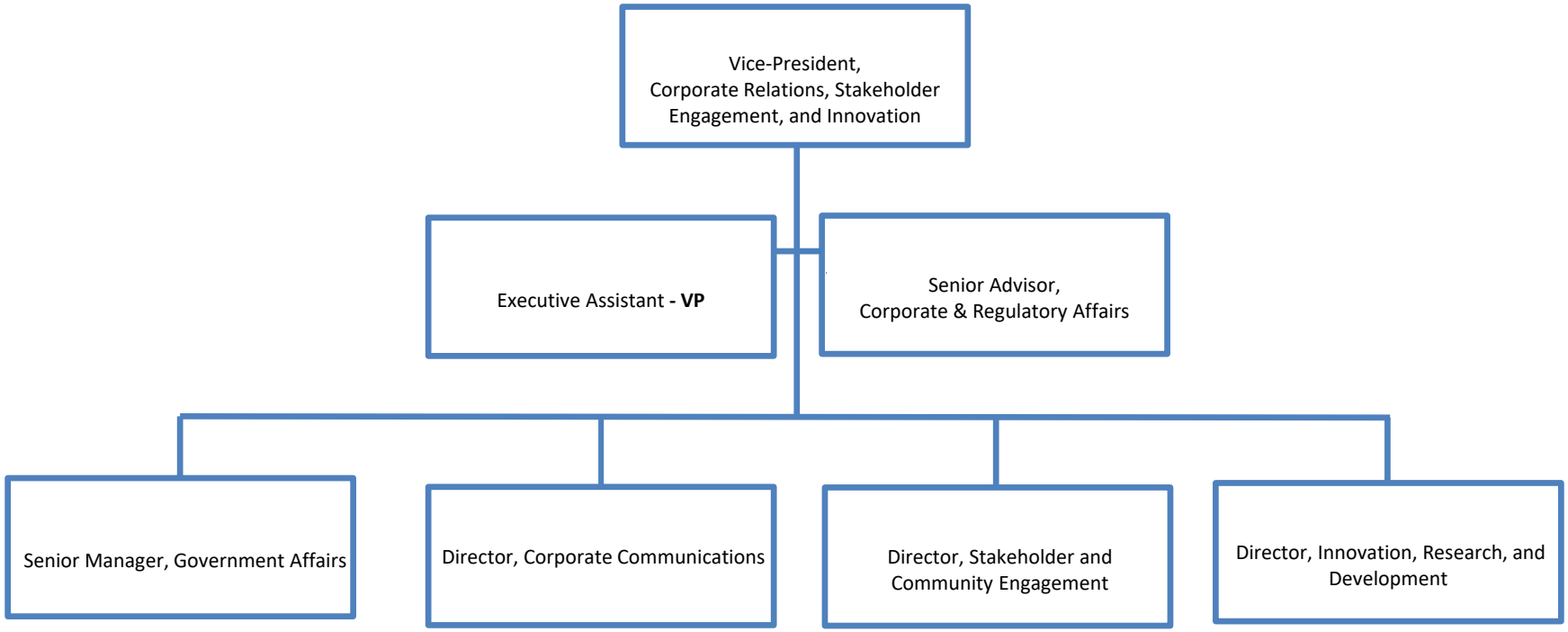
Exhibit	Tab	Schedule	DESCRIPTION
A – ADMINISTRATION & APPLICATION SUMMARY			
A	1	1	Exhibit List
A	1	2	2024 Submission
A	1	3	2025 Submission
A	1	4	Executive Summary
B – BUSINESS PLAN & FINANCIAL INFORMATION			
B	1	1	Minister's Letter on Powering Ontario's Growth
B	1	2	Amendment to the 2023-2025 Business Plan
B	1	3	Approval Letter of the Amendment to 2023-2025 Business Plan from the Minister of Energy
B	1	4	Interim Year Business Outlook 2023-2026
B	1	5	2023-2025 Business Plan
B	1	6	2023 Annual Report and Audited Financial Statements (to be filed at a later date)
C – REVENUE REQUIREMENT AND USAGE FEES			
C	1	1	Incremental Revenue Requirement and Usage Fee Methodology
C	2	1	2024-2025 Incremental Revenue Requirements and Usage Fees
D – OPERATING EXPENDITURES			
D	1	1	Incremental OM&A Overview Attachment 1 - Summary of OM&A Expenses (Appendix 2-JA) (xlsx)
D	1	2	OM&A Business Unit Detail Attachment 1 - OM&A Business Unit Table (Appendix 2-JC) (xlsx) Attachment 2 - Organizational Chart

Exhibit	Tab	Schedule	**DESCRIPTION**
D	1	3	Staffing and Compensation Attachment 1 - Employee Costs (Appendix 2-K) (xlsx)
F – DEFERRAL AND VARIANCE ACCOUNTS			
F	1	1	Forecast Variance Deferral Account

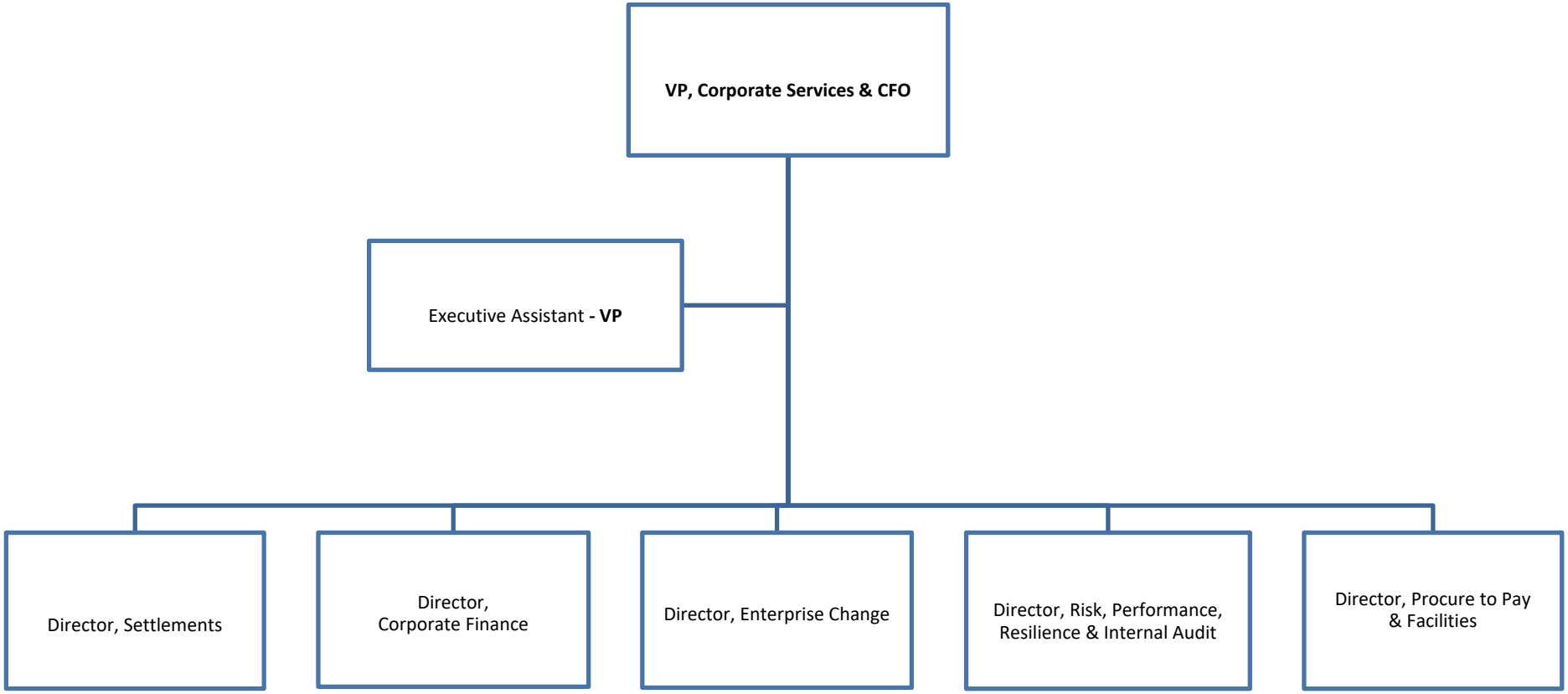
IESO


President & CEO
Executive Assistant
Director, Corporate Strategy
Senior Advisor
Program Delivery Executive
VP, Corporate Services & CFO
VP, Planning, Conservation & Resource Adequacy & CETO
VP, Information & Technology Services and CIO
VP, General Counsel & Chief Reliability Compliance Officer
VP, Market Assessment & Compliance
VP, Corporate Relations, Stakeholder Engagement & Innovation
VP, Human Resources
COO & VP, Markets & Reliability

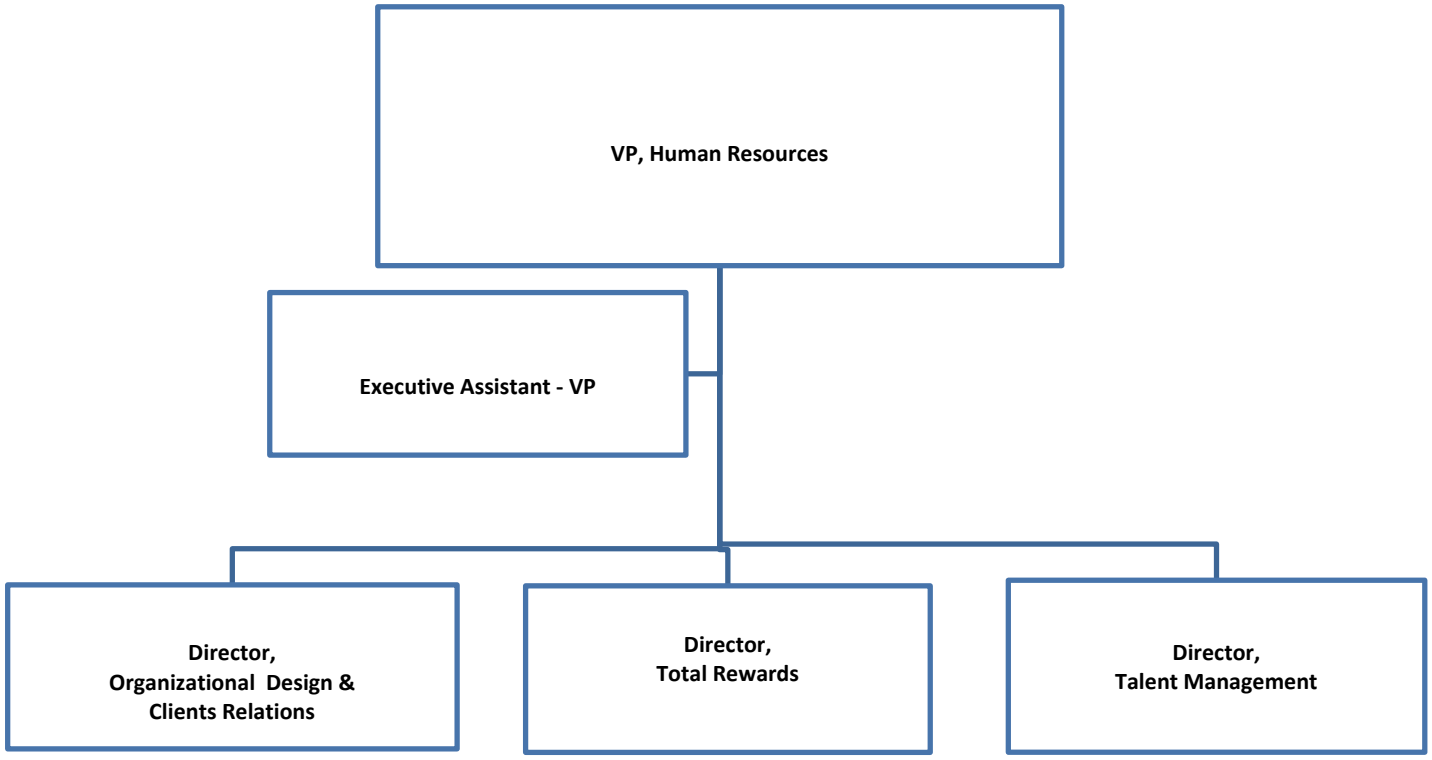
CORPORATE RELATIONS, STAKEHOLDER ENGAGEMENT & INNOVATION



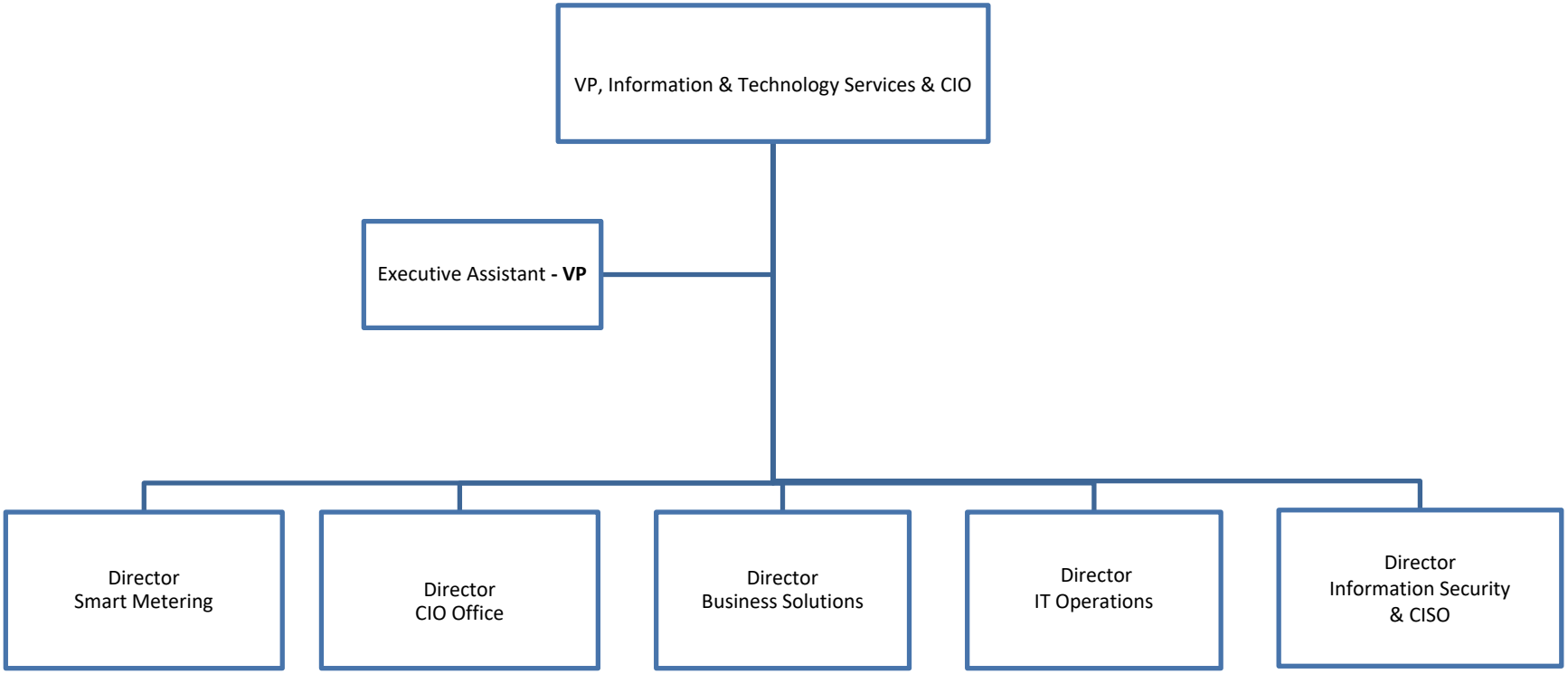
CORPORATE SERVICES



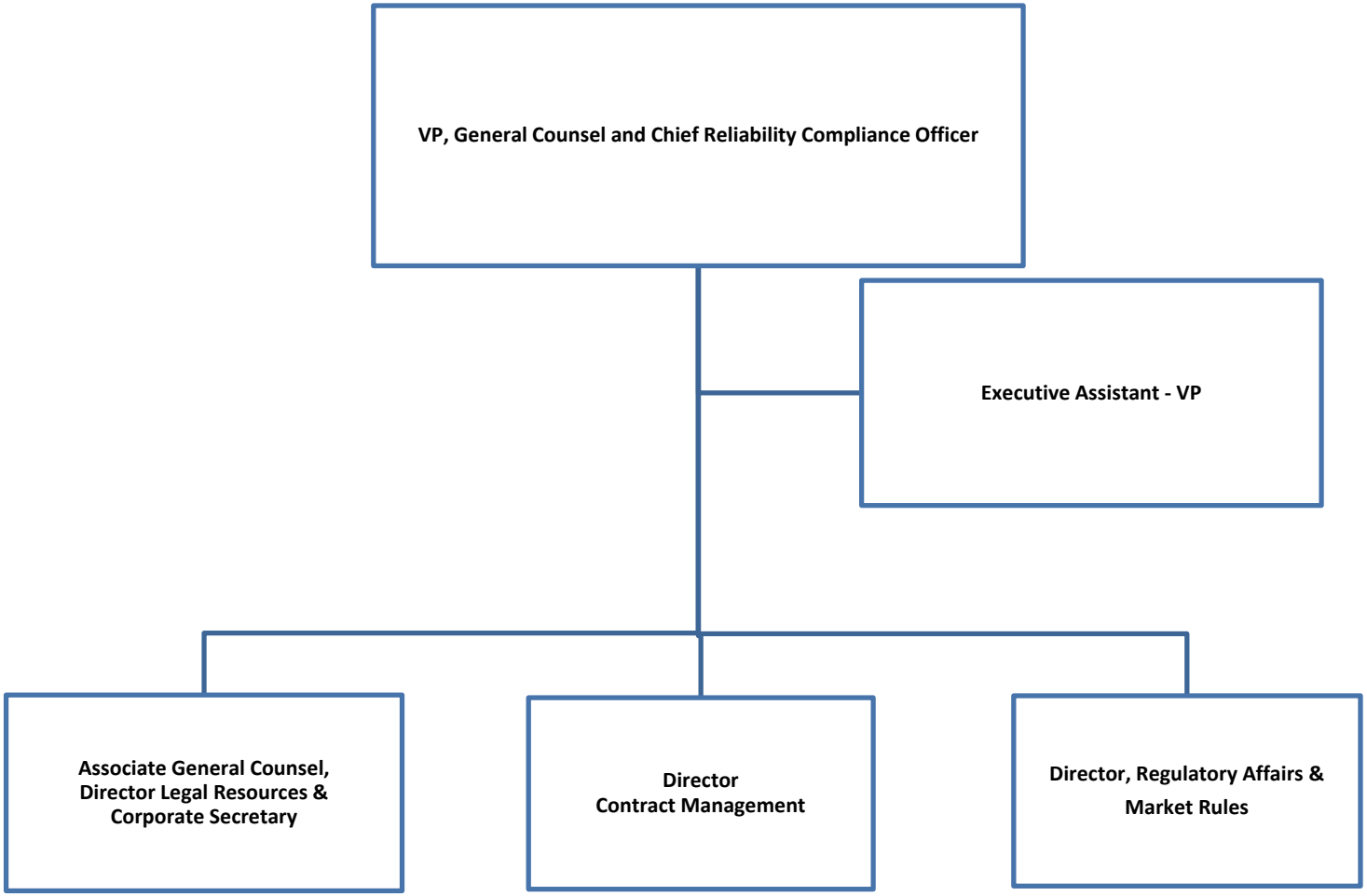
HUMAN RESOURCES



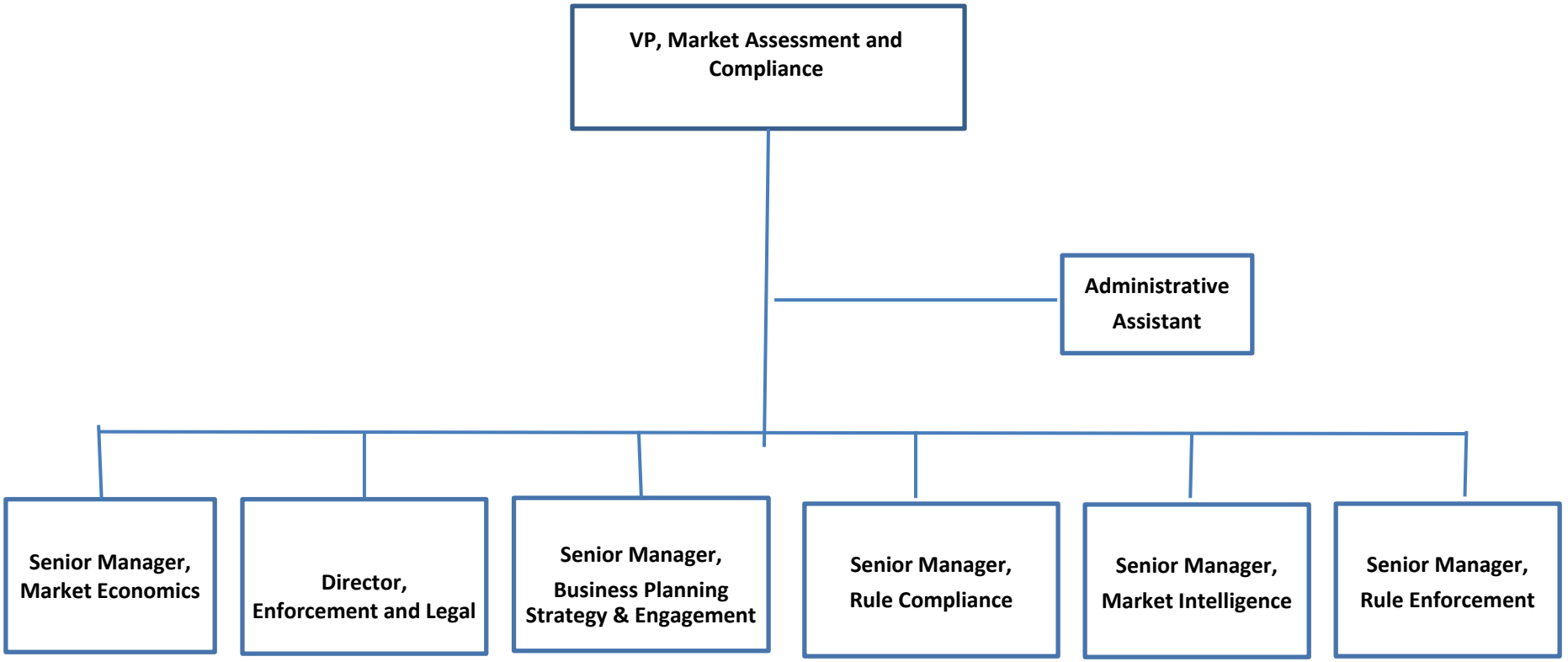
INFORMATION & TECHNOLOGY SERVICES



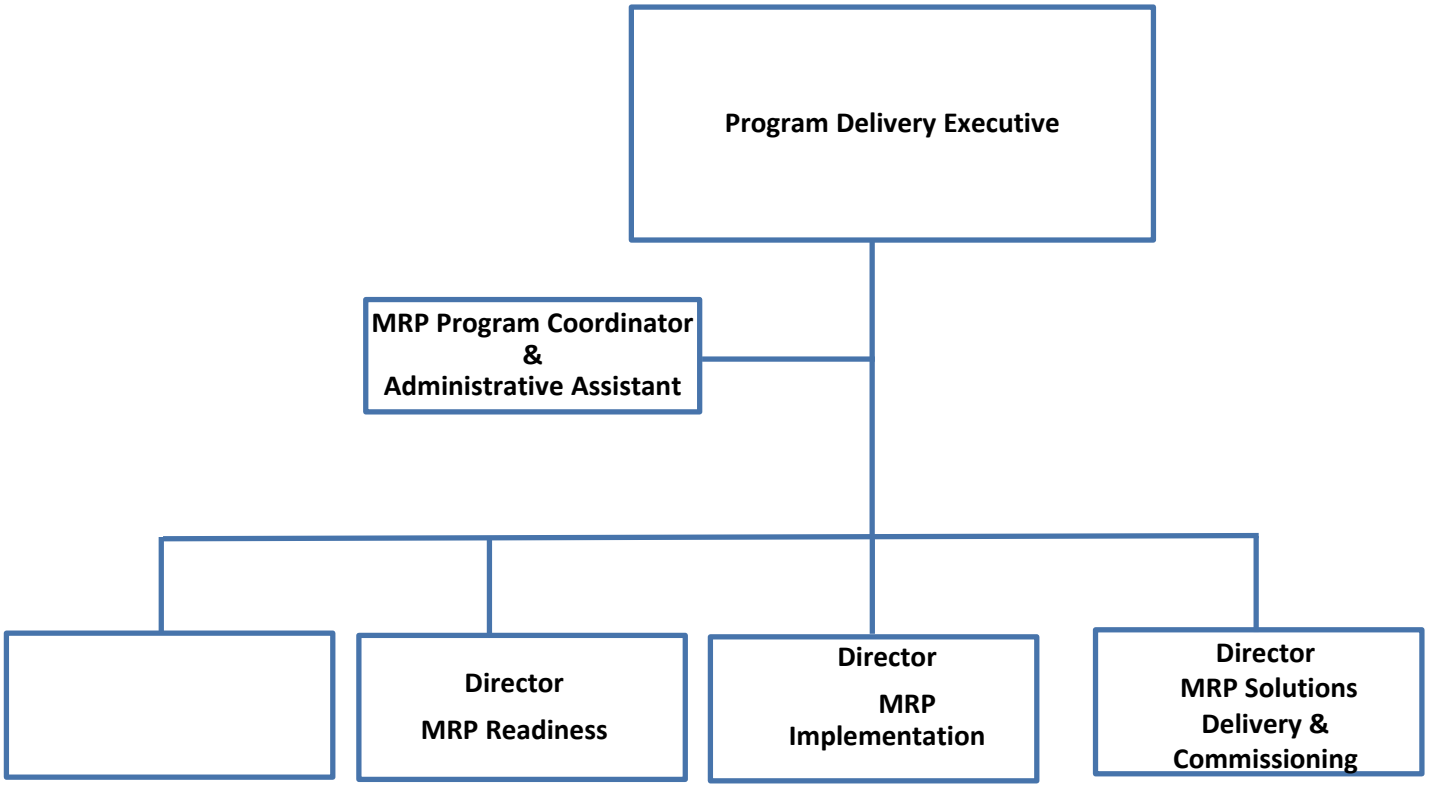
LEGAL RESOURCES AND CORPORATE GOVERNANCE



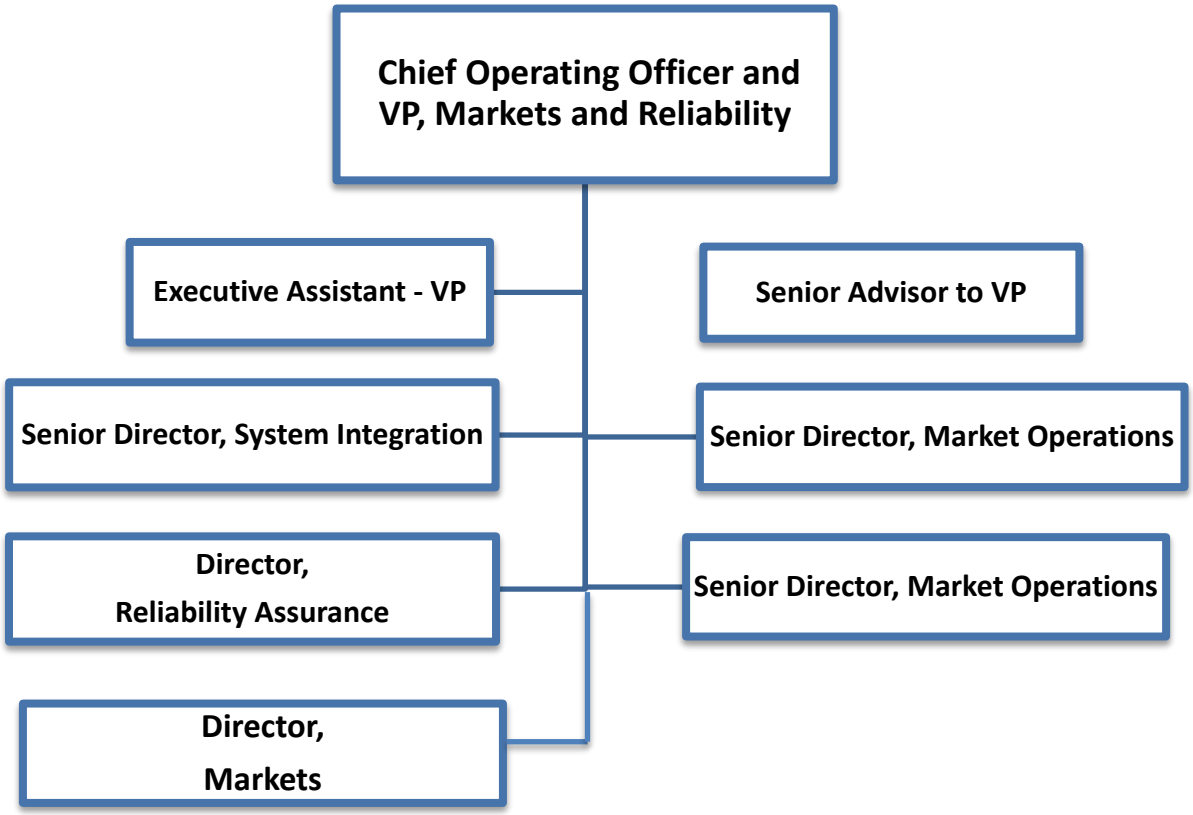
MARKET ASSESSMENT AND COMPLIANCE DIVISION



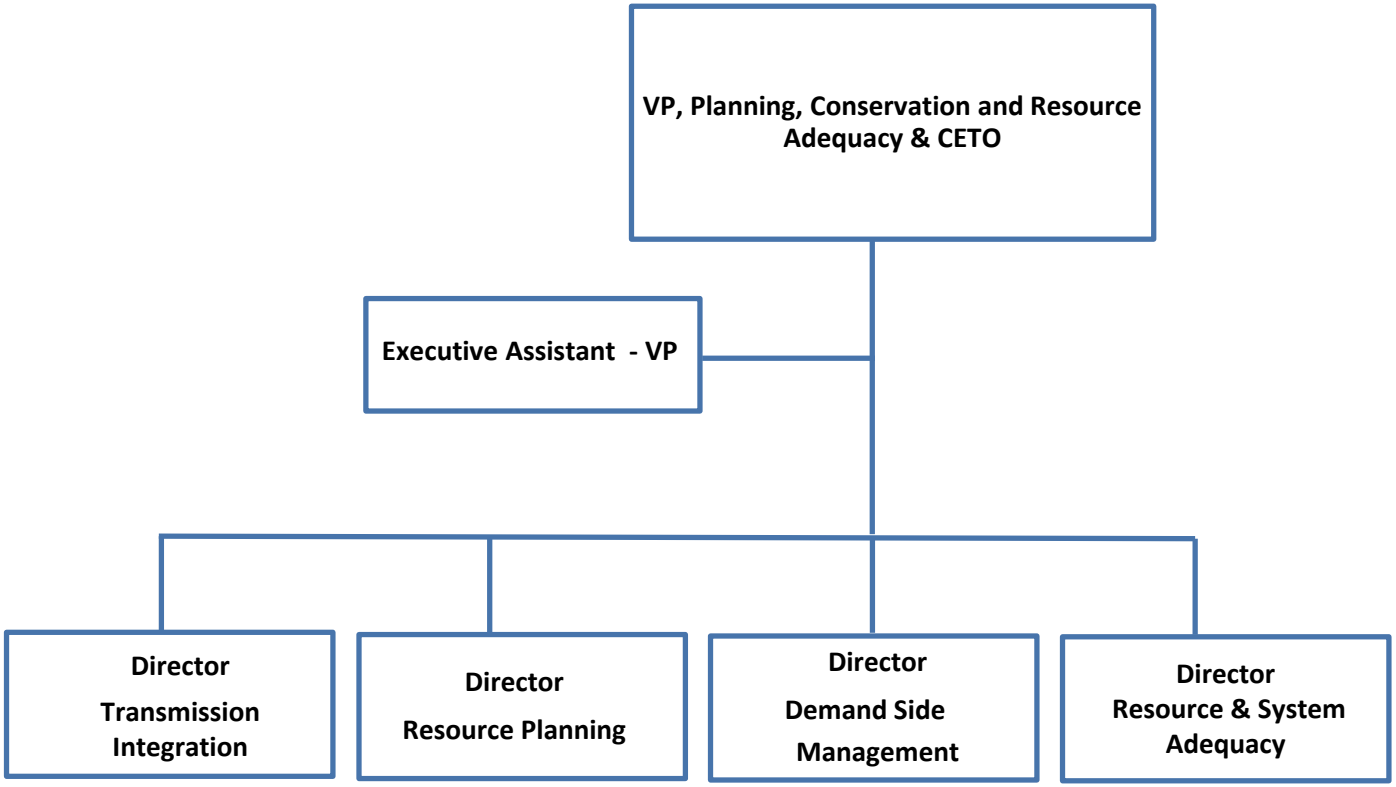
MARKET RENEWAL PROGRAM



MARKETS AND RELIABILITY



PLANNING, CONSERVATION & RESOURCE ADEQUACY



TAB 7

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

DECISION AND ORDER

EB-2019-0242

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO

Application to review amendments to the market rules made by the Independent Electricity System Operator

BEFORE: Cathy Spoel
Presiding Member

Emad Elsayed
Member

Susan Frank
Member

January 23, 2020

TABLE OF CONTENTS

1 INTRODUCTION AND SUMMARY 1

2 PROCESS 2

2.1 THE APPLICATION 2
2.2 NOTICE OF HEARING, INTERVENTIONS, COST RESPONSIBILITY AND COST AWARD ELIGIBILITY 2
2.3 MOTION TO STAY 3
2.4 HEARING OF THE APPLICATION 4

3 BACKGROUND 5

4 THE STATUTORY TESTS 8

5 POSITIONS OF THE PARTIES 11

5.1 OVERVIEW OF THE PARTIES' EVIDENCE 11
5.2 AREAS OF AGREEMENT 12
5.3 DISPUTED MATTERS 13

6 ORDER 28

1 INTRODUCTION AND SUMMARY

This is the Decision and Order of the Ontario Energy Board (OEB) on an application filed by the Association of Major Power Consumers in Ontario (AMPCO) for an order revoking a set of amendments to the wholesale electricity market rules made by the Independent Electricity System Operator (IESO) (Amendments), and referring them back to the IESO for further consideration (Application). The Application was filed under section 33 of the *Electricity Act, 1998* (Act). AMPCO also filed a Notice of Motion requesting an order of the OEB under section 33(7) of the Act staying the operation of the Amendments pending the completion of the OEB's review.

The Amendments at issue (MR-00439-R00 to -R05) enable the evolution of the IESO's Demand Response Auction into a Transitional Capacity Auction, including notably to allow participation by generators that are neither under contract nor rate-regulated. The Amendments were published by the IESO on September 5, 2019 and had an effective date of October 15, 2019.

By Decision and Order dated November 25, 2019, the OEB stayed the operation of the Amendments pending completion of the OEB's review and issuance by the OEB of its order embodying its final decision in this proceeding. The OEB is required by section 33(6) of the Act to issue that order within 120 days of receipt of the Application.

The OEB has considered the Amendments against the statutory tests set out in section 33(9) of the Act, and has concluded that the Amendments: (i) are not inconsistent with the purposes of the Act; and (ii) do not unjustly discriminate against or in favour of a market participant or class of market participants. Accordingly, the Application is dismissed and the stay of the operation of the Amendments is lifted.

2 PROCESS

2.1 The Application

The Application was filed on September 26, 2019 by AMPCO, an organization that represents major power consumers in Ontario, some of whom participate in the IESO-administered markets as Demand Response Resources (DR Resources).

The Application concerns the IESO's new capacity market. The IESO developed a capacity auction (the Transitional Capacity Auction or TCA) to secure capacity commitments to participate in that market. Both DR Resources and dispatchable generating facilities that are neither under contract nor rate regulated are eligible for participation in the TCA. The TCA builds on the IESO's former Demand Response Auction (DRA), which has been in place since December 2015, in which only capacity offered from DR Resources was procured. The Amendments at issue in this proceeding enable that evolution.

The Application requests that the OEB revoke the Amendments and refer them back to the IESO for further consideration on the grounds that the Amendments are: (i) inconsistent with the purposes of the Act; and / or (ii) unjustly discriminatory to DR Resources. According to the Application, the inequity in treatment regarding payment terms for DR Resources and generation resources is unjustly discriminatory to the DR Resources, and will result in outcomes that are inconsistent with the Act. AMPCO's claim is that their capacity offers in the auction will not be able to compete with those of generation resources, since the latter receive an energy payment if dispatched in addition to an availability payment.

As part of its Application, AMPCO also filed a Notice of Motion requesting an order of the OEB staying the operation of the Amendments pending the completion of the OEB's review (Motion to Stay).

2.2 Notice of Hearing, Interventions, Cost Responsibility and Cost Award Eligibility

A Notice of Hearing was issued on October 1, 2019. The OEB attended to service of the Notice of Hearing on all electricity licensees as well as on all entities identified by the IESO as participants in the 2015, 2016, 2017 and 2018 DRAs.

In Procedural Order No. 1, issued on October 4, 2019, the OEB ordered AMPCO to file all affidavit material on which it intended to rely, whether in support of its Application or the Motion to Stay, by October 11, 2019. AMPCO filed affidavit material on that day.

In response to the Notice of Hearing, several interested parties requested intervenor status, the Ontario Energy Association requested observer status, and the Canadian Manufacturers & Exporters indicated that it would be monitoring the proceeding as it unfolded.

On October 18, 2019, the OEB issued Procedural Order No. 2, which established procedures and timelines for dealing with the Application and the Motion to Stay in parallel[1], and granted intervenor status to all those that requested it; namely:

- Advanced Energy Management Alliance (AEMA)
- Association of Power Producers of Ontario (APPrO)
- Capital Power Corporation (Capital Power)
- Kingston CoGen Limited Partnership (KCLP)
- Rodan Energy Solutions Inc. (Rodan)
- School Energy Coalition (SEC)
- TransAlta Corporation (TransAlta)
- IESO

AEMA, Capital Power, Rodan and TransAlta did not actively participate in this proceeding.

In Procedural Order No. 2, the OEB also stated that it intended for the IESO to bear the costs of this proceeding, but invited the IESO to make a submission if it wished to object to bearing the costs of this proceeding or to object to any of the requests for cost award eligibility made by AMPCO, APPrO, SEC and KCLP. After consideration of submissions filed by various parties, the OEB issued its Decision on Cost Responsibility & Cost Eligibility on November 12, 2019. In that Decision, the OEB determined that: (i) the IESO shall bear the costs of this proceeding; (ii) AMPCO, SEC and APPrO are eligible for an award of costs; and (iii) KCLP is not eligible for an award of costs.

2.3 Motion to Stay

In support of their positions on the Motion to Stay, evidence was filed by AMPCO, the IESO and KCLP. Submissions on the Motion to Stay were filed by AMPCO, the IESO, KCLP, APPrO and OEB staff. A Decision and Order staying the operation of the Amendments was issued on November 25, 2019.

[1] Subsequent procedural orders amended, revised or supplemented the procedures and timelines established in Procedural Order No.2.

2.4 Hearing of the Application

Evidence in respect of the Application was filed by AMPCO, the IESO, KCLP and OEB staff. The hearing on the Application commenced on November 25, 2019 and continued on November 28 and 29. Written summaries of planned oral arguments were filed by AMPCO, the IESO, KCLP, APPrO and OEB staff on December 9, 2019. Oral argument by these parties, as well as by SEC, was heard on December 12 and 13, 2019.

3 BACKGROUND

The IESO-Administered Markets

The IESO-administered markets consist of several wholesale markets including energy and operating reserve, procurement markets for ancillary services and, most recently, a market to procure capacity.

The wholesale energy market is the cornerstone of the IESO's market architecture, and has operated since the market opened in 2002. Both generation and load facilities participate in the IESO's markets. Some generation and load facilities are dispatchable – that is, they have the capability to adjust their level of energy production or consumption in response to dispatch instructions received from the IESO. In the IESO's real-time energy market, dispatchable generators and loads make offers to supply and bids to consume energy, respectively. The IESO determines a market clearing price every five minutes, and also sends dispatch instructions to all dispatchable market participants every five minutes. Dispatchable generators are paid the market clearing price for the energy they produce and inject into the grid. Dispatchable loads pay the market clearing price for the energy they withdraw from the grid.

The Developing Capacity Market

The IESO's energy market has been modified over time to incorporate contracted generating resources, to integrate significant amounts of renewable generation, and to support other changes. More recently, similar to other organized wholesale markets in North America, the IESO began to develop a market mechanism to procure capacity.

In 2015, the IESO launched the DRA to procure capacity from DR Resources, which commit to being available to reduce consumption based on market prices during a pre-defined commitment period. The DRA has been run each year in early December, and the associated commitment periods run from May 1 to October 31 for the summer period, and November 1 to April 30 for the winter period.

There are two types of DR Resources that can participate: dispatchable loads and Hourly Demand Response resources. The latter may be dispatched on an hourly basis for up to four hours. There are two types of Hourly Demand Response resources: physical resources, which are directly connected to the IESO-controlled grid; and virtual resources, which typically provide demand response capability through a portfolio of contributors connected at the distribution level.

DRA participants make capacity offers that consist of megawatts of capacity and prices at which they are willing to agree to a capacity commitment. The IESO decides how much DR capacity it wants to procure and at what price. The auction clears where supply

equals demand; this intersection determines the price paid for capacity for the upcoming commitment periods. All proponents whose capacity offer prices are equal to or lower than the auction clearing price are selected for capacity commitments. Regardless of their offer, each DR Resource receives the same auction clearing price for each megawatt of capacity they make available for curtailment upon dispatch from the IESO during the commitment period.

DR Resources make their capacity available by submitting bids to buy energy in each of the "availability window" hours within a business day. The energy bids identify the maximum prices DR Resources are willing to pay for energy. Market prices higher than a DR Resource's bid price results in that DR Resource being dispatched to curtail consumption. There is no payment provided to DRA participants when they are dispatched to curtail consumption, but at the same time they also do not pay for the electricity they are no longer consuming.

The TCA is designed to work in much the same way as the DRA, except that dispatchable generators that are neither under contract nor rate-regulated compete for capacity commitments alongside dispatchable loads and Hourly Demand Response resources. As with the DRA, the TCA design is such that all resources that clear the TCA receive the same availability payment for each megawatt of capacity made available during the commitment period. As with the DRA, DR Resources make their capacity available by submitting bids to buy energy, and are dispatched to curtail consumption to the extent that market prices are higher than their bid prices. Generators who are successful in the TCA have to offer supply into the energy market during the TCA commitment period. Like other generators, they are paid for energy injections at the prevailing market clearing price when dispatched to produce electricity, consistent with initial market design and market rules that pre-date the Amendments made by the IESO in respect of the TCA.

Out-of-Market Payments

A significant feature of the IESO-administered markets is the range of supplemental payments made available outside of the IESO's energy market. These out-of-market payments (so called because the payments are not reflected in the market price for energy) are largely motivated by reliability imperatives that can at times require market participants to operate when it is otherwise uneconomic for them to do so. Different classes of market participants are eligible for different forms of out-of-market payments.

One particular form of out-of-market payment that received significant attention in this proceeding are payments made to generators under the real-time generation cost guarantee (GCG) program. The IESO created this program to manage the reliability risk of generators with large start-up costs opting not to run on days when they may not be

able to recover their costs through prevailing energy prices. In its current form, the GCG program guarantees non-quick start gas-fired generators recovery of their costs to start up and be available (e.g., fuel, incremental operating & maintenance) should market revenues fall short. Absent the GCG program, the only way for a non-quick start generator to attempt to recover these costs is to include an estimate of them in their energy offer prices.[2]

[2] KCLP oral argument, transcripts, v.4, p.120

4 THE STATUTORY TESTS

As set out in section 33(9) of the Act, the tests that apply when reviewing market rule amendments are whether they: (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.

There has been only one prior case under section 33 of the Act in respect of which the OEB issued a final decision. [3] In that case, the OEB determined that unjust discrimination in the context of section 33 of the Act means unjust *economic* discrimination.[4] That case also established that the burden of proof in demonstrating whether market rule amendments pass or fail the statutory tests is on the applicant.[5] All of the parties agreed that these principles are applicable in the current proceeding.

AMPCO's application initially contended that the Amendments failed both of the statutory tests, but later stated that inconsistency with the purposes of the Act flows from unjust discrimination, and that absent unjust discrimination there is no issue with consistency with the purposes of the Act.[6] Accordingly, the central issue in this case is whether the Amendments, by allowing generators and loads to compete in an expanded capacity auction, have the effect of being unjustly discriminatory to DR Resources. Parties made various submissions on whether or not the Amendments were unjustly discriminatory to DR Resources, but generally concurred with the definition of "unjust discrimination" suggested by OEB staff in its written summary of argument; namely, different treatment that is not justified by a difference in circumstances.[7]

While generally agreeing with OEB staff's definition, SEC submitted that the impact of the Amendments on ratepayers must be considered in assessing whether any economic discrimination is unjust.[8] The IESO argued that determining whether discrimination is 'unjust' requires consideration of the interests of others such as the IESO, consumers and generators.[9]

OEB staff submitted that the key underlying question is the degree to which generation and DR Resources are in substantially similar circumstances with respect to their characteristics and to the services they provide to the IESO-administered markets. In the event that their circumstances are found to be dissimilar, different treatment may be

[3] EB-2007-0040
[4] EB-2007-0040, Decision and Order, p.26
[5] EB-2007-0040, Decision and Order, p.18
[6] AMPCO oral argument, transcripts, v.4, p.1-2
[7] OEB staff written argument, p.4
[8] SEC oral argument, transcripts, v.4, p.96
[9] IESO written argument, para 10

discriminatory but would not be unjustly so. However, if their circumstances are substantially the same, different treatment in the broader economic context – that is, through the IESO's market design and its supporting rules – would result in the Amendments being unjustly discriminatory.[10]

There was disagreement among the parties as to whether the test for unjust discrimination is qualitative or quantitative. AMPCO argued that "unjust" discrimination in this statutory context means discrimination that is not economically justified and that it is a *qualitative – not a quantitative* – test.[11] SEC argued that the test for unjust discrimination is not entirely qualitative, and that there has to be some material negative impact, otherwise the question of what constitutes discrimination becomes an entirely theoretical discussion.[12] The IESO agreed with SEC's argument and also submitted that, if the risk of a DR Resource being activated (and incurring the related activation costs) is "infinitesimally small", then there is no unjustness.[13]

All parties, including the IESO, agreed that it was appropriate to consider the Amendments in the broader market context and not in a 'vacuum'.[14] However, the IESO's position was that AMPCO's requested remedy of revoking the Amendments because other market rules and the original market design may make the Amendments unjustly discriminatory to DR Resources amounts to an impermissible challenge to those other rules.[15]

AMPCO clarified its position that it was not asking the OEB to find whether or not the IESO should implement energy or activation payments for DR Resources and that there are other options and approaches that have been successfully and relatively easily implemented in the past.[16] In any event, AMPCO concluded that, while there are "fixes" available that do not involve disrupting existing market rules, it is not a problem for the OEB to solve but rather the IESO.

Findings

The OEB finds that the question of consistency with the purposes of the Act is only relevant to the extent there is unjust discrimination. In no other manner are the Amendments inconsistent with the purposes of the Act.

[10] OEB staff written argument, p.4
[11] AMPCO written argument, paras 13-17 and oral argument, transcripts, v.4, p.36-37
[12] SEC oral argument, transcripts, v.4, p.95
[13] IESO oral argument, transcripts, v.4, p.170
[14] IESO oral argument, transcripts, v.4, p.153
[15] IESO oral argument, transcripts, v.4, p.152-153
[16] AMPCO oral reply argument, transcripts, v.5, p.19-20

On the matter of discrimination, the OEB finds that, as in the Ramp Rate case[17], discrimination means economic discrimination.

On the question of whether the Amendments are unjustly discriminatory, the OEB finds that three elements are required.

First, there must be economic discrimination. Discrimination can arise from differences in treatment and, in the context of the electricity markets, this can mean differences in treatment for different classes of market participants when considered in the context of the IESO-administered market as a whole.

Second, it must be shown that the difference in treatment is not justified by a difference in circumstances. This is not to say that differently situated parties cannot be treated differently; treatment can be unequal yet not inequitable or "unjust". It is only different treatment in the absence of material and relevant differences in the situation or characteristics among the affected market participants that raises the prospect of unjust discrimination.

Third, the claim of discrimination cannot be purely qualitative; it must have some quantitative aspect to it. The OEB appreciates that as the Amendments are prospective, quantification will be based on estimates and assumptions about the operation of the market, but within that context, the OEB requires adequate information on the nature and extent of the economic impacts in order to make a finding of unjust discrimination.

With respect to the IESO's argument that the OEB does not have jurisdiction to review the Amendments, as the OEB noted in its decision on the Motion to Stay, the fact that the lack of energy payments for DR Resources may be a circumstance that results in the Amendments being discriminatory does not mean that, in reviewing the Amendments, the OEB is conducting a review of the market rules relating to energy payments. The OEB maintains that view in this Decision.

[17] EB-2007-0040

5 POSITIONS OF THE PARTIES

5.1 Overview of the Parties' Evidence

Colin Anderson, in his capacity as president of AMPCO, was the witness for the applicant. Mr. Anderson's testimony described the reasons behind AMPCO's view that the absence of energy market payments to DR Resources for energy delivered via curtailment would put DR Resources at a competitive disadvantage in the TCA and would likely cause them to be replaced by generators. He provided examples involving a steel manufacturer as a DR Resource that incurs costs analogous to those of generators in order to deliver energy.

The IESO's witnesses were David Short, Director of Capacity Market Design, and Candice Trickey, Director of Demand Side Strategy. They described the operation of the IESO's markets, the Amendments that establish the TCA, the design of prior DR programs, and other features of the IESO's market programs such as the GCG program.

John Windsor, Vice President of Energy Services & Asset Management of Northland Power Inc. appeared as a witness on behalf of KCLP, a partnership that owns a gas-fired generator that would be eligible to participate in the TCA. Northland Power Inc. is an owner of KCLP. He provided background on the generation facility and described the significance of potential revenues through the TCA in any decision to continue to operate the facility in the Ontario market.

Brian Rivard appeared as an expert witness on behalf of KCLP. Dr. Rivard's testimony introduced the concept of horizontal equity and included detailed scenario analyses of the offer strategies of differently configured market resources in the presence or absence of energy payments for DR Resources.

OEB staff retained London Economics International (LEI), specifically A.J. Goulding and Adam Hariri, as expert witnesses, to prepare an independent report and provide testimony with a focus on how DR Resources are compensated in U.S. markets that are subject to the jurisdiction of the Federal Energy Regulatory Commission, including consideration of energy, capacity and other payments. LEI identified key contextual differences between the markets in Ontario and the U.S.; among others, those differences include the disconnect between wholesale electricity prices and fixed retail rates that presented a barrier to demand response in the U.S.

While APPrO and SEC participated actively in the cross examination of witnesses and argument, neither provided evidence or witnesses of their own.

5.2 Areas of Agreement

In addition to the areas of agreement amongst the parties noted in section 4 above, there also appeared to be general agreement among the parties that:

- The Amendments are not inconsistent with the purposes of the Act, except for the issue of unjust discrimination on which the parties were divided
- There is a need to retain additional capacity resources in order to maintain reliability
- The use of competition is an appropriate means to retain additional resource commitments
- DR Resources and generators are functionally equivalent regarding their ability to balance supply and demand upon dispatch in the energy market

An area about which there was partial agreement pertains to the costs of providing DR, and the differences in the kinds of costs that DR Resources may incur when doing so. Given the significance of the question of costs to the proceeding, the OEB sees benefit in describing these in further detail.

The first point of agreement pertains to the concept of the value of lost load, or VOLL – that for any given energy consumer, there is a maximum price for energy above which the consumer would rather forgo the opportunity to consume the energy than pay to continue consuming. It was not contested that this value can vary by consumer. A VOLL would be equal to the added value that a load derives from the energy as an input in the production of a product or service. This concept arose frequently in the hearing.

There also appeared to be no general disagreement among the parties that DR Resource costs could be categorized as follows:

- *Cost related to availability*: These are the costs that a DR Resource would incur in order to be a participant in the DRA, and be available in the event a DR activation arises.
- *Costs related to an activation event*: Such costs would parallel the start-up costs faced by a non-quick start generator.
- *Costs related to the amount of energy made available via an activation to curtail demand:* These costs parallel a generator's marginal costs of generating electricity.

There was also general agreement that the first type of costs (related to availability) are appropriately recovered via DR Resource offer prices in the TCA.

Parties further generally agreed that there are activation costs for both generation and DR Resources. However, there was no consensus as to the nature of those costs and

whether they should be included in offers made by DR Resources in the capacity market or in the bids they make in the energy market. Parties disagreed whether these costs could be managed by DR Resources via their TCA bids, should be compensated through the provision of energy payments like those made to generators or should be compensated by creating for DR Resources an out-of-market mechanism similar to the GCG program. The specific positions of the parties in relation to this matter are discussed below.

It was also noted that the latter two cost categories, which relate to DR activation costs, can arise out-of-market when DR Resources are either tested or activated to assist the IESO in responding to emergency conditions on the grid. Parties agreed that, since these are out-of-market activations, DR Resources cannot manage any resulting costs via their bid prices in the energy market. The IESO has recently adopted market rule amendments that will provide compensation to Hourly Demand Response resources for test and emergency activations.[18]

5.3 Disputed Matters

AMPCO's fundamental position in this proceeding is that the Amendments are unjustly discriminatory to DR Resources since they will be unable to compete on a level playing field with generation resources in their bidding in the TCA.

By contrast, the position of the intervenors that participated in the proceeding (IESO, KCLP, APPrO and SEC) was that the Amendments are not unjustly discriminatory for various reasons.

The positions of the parties and OEB staff on areas where there was no agreement are discussed further below.

Do the Amendments have an unjustly discriminatory effect given the payments available to generators in the energy market? Do the Amendments have an unjustly discriminatory effect given payments available to generators outside of the energy market? Has there been an assessment of these issues?

In this proceeding, an inquiry into the presence of economic discrimination requires an assessment of the kinds of payments resources are eligible for in the IESO-administered markets. As discussed in section 3 above, the two main categories of payment are energy payments (paid to generators upon dispatch) and out-of-market payments.

[18] The market rule amendments did not contain provisions to compensate DLs for test and emergency activations as they already benefit from the make whole payment program related to local prices that Ms. Trickey briefly described. Transcripts, v.3, p.30-31

A. Absence of energy payments for DR Resources

AMPCO

AMPCO argued that, while DR and generation resources clearing the TCA are each obligated to also participate in the energy market with daily bids and offers, respectively,[19] and both incur costs when activated in the energy market, only generators receive payments for activation. All generators receive energy payments, and some also receive payments under the GCG program.[20] [21] Generators therefore do not need to factor the risk of incurring costs of activation into their capacity offers.[22]

In contrast, DR Resources must include forecast activation costs in their TCA bids, or risk activation and incurring associated costs without compensation. AMPCO contends that the effect of the Amendments is therefore to create a TCA in which DR Resources must compete with generators at a disadvantage.[23]

AMPCO argued that, given the functional equivalence of the services provided by DR Resources and generation resources, there is no economic justification for DR Resources having to recover anticipated activation costs through their TCA bids, or risk losses, when generators can recover costs associated with their dispatch in the energy market through payment streams not available to DR Resources.[24] [25] The absence of economic justification for discriminating against DR Resources makes the discrimination "unjust" and AMPCO summed it up as follows:

> *Functional equivalence, different compensation, lack of economic justification; that is the 'unjust' component of the 'unjust discrimination' test under s.33 of the Act.*[26]

IESO

The IESO's position is that the Amendments are not unjustly discriminatory because they treat DR and generation resources equally in the TCA. That is, all DR and generation resources that successfully bid into the TCA receive the same availability payments

[19] AMPCO oral reply argument, transcripts, v.5, p.24
[20] AMPCO oral argument, transcripts, v.4, p.11
[21] Transcripts, v.2, p.29
[22] AMPCO oral argument, transcripts, v.4, p.34
[23] AMPCO oral reply argument, transcripts, v.5, p.12
[24] AMPCO written argument, paras 13–17 and oral argument, transcripts, v.4, p.36-37
[25] AMPCO oral argument, transcripts, v.4, p.11
[26] AMPCO oral argument, transcripts, v.4, p.11-12

irrespective of whether they are subsequently economically activated in the energy market.[27]

The IESO argued that there is no evidence that the current market design that treats generators and load participants differently in the energy market is defective or inequitable, and what evidence there is, is that there is no basis for making energy payments to DR Resources.[28]

The IESO further indicated whether DR resources should receive energy payments is an energy market design issue that is "irrelevant to the main point [at] issue [in this proceeding], which is, is there any competitive disadvantage in the capacity auction".[29] The IESO also noted that it is currently undertaking a stakeholder engagement process to assess whether DR Resources should receive energy payments. The IESO stated it will make a final decision on that matter in June 2020. The IESO agreed that the scope of that stakeholder engagement would be broadened to assess activation payments, as well as energy payments, given the amount of discussion related to out-of-market GCG payments to generators.[30]

KCLP

KCLP supported the IESO's position that, under the TCA, DR and generation resources are treated exactly the same: they compete in an auction to provide a unit of capacity, and every participant that clears the auction receives exactly the same auction clearing price. Both DR Resources and generators are given a fairly high degree of discretion to establish their energy market bids or offers at a price which allows them to recover their VOLL or their variable costs of providing energy when activated.[31] KCLP referred to the evidence of Dr. Rivard, who noted that "not getting an energy payment right now, based on history seeing how often they would actually be activated is, in my words, *de minimus* in expectation, in which case they could offer in that capacity auction exactly the same that they would have had generators not been there".[32]

KCLP also argued that, if DR Resources received an energy payment for an economic activation, it would be a double benefit because the DR Resource avoids the cost of consuming and would also receive an energy payment from the IESO to avoid this cost.[33]

[27] IESO written argument, p.1
[28] IESO oral argument, transcripts, v.4, p.152-153
[29] Transcripts, v.5, p.28
[30] Transcripts, v.3, p.91-93
[31] KCLP written argument, paras 18-24
[32] Transcripts, v.2, p.191
[33] KCLP written argument, para 38

APPrO

APPrO stated that it relied largely on the independent expert evidence filed by KCLP to establish that the Amendments afford fair and equitable treatment to auction participants and do not unjustly discriminate against DR resources.[34] APPrO also referred to the evidence of Dr. Rivard in support of its position that paying an energy payment to DR Resources for economic activations would afford a competitive advantage to DR Resources over generators in the TCA.[35]

OEB Staff

OEB staff submitted that there are key differences in circumstances between generation and DR Resources. When generation is dispatched, it sells energy it owns into the market. When making energy available to other loads via a curtailment, a DR Resource is simply choosing not to buy energy.

Given the evident differences in the circumstances of generation and load resources, the difference in eligibility for energy payments to generation and DR Resources upon dispatch is not unjustly discriminatory. Further, an energy payment to DR Resources would constitute a double payment for the reduction in demand in addition to avoided costs.[36]

SEC

SEC argued that, in order to show that the Amendments are unjustly discriminatory, AMPCO would need to demonstrate that there is a material negative impact and not just theoretically. If there is no discrimination, in fact, then there is no unjust discrimination.[37]

As a more general matter, SEC raised a concern that the IESO should have done the economic assessment on the issue of energy payments or activation payments to DR Resources before the Amendments were approved by the IESO Board of Directors. SEC noted that it is important to remember that only the IESO has the information to properly undertake such an empirical analysis.[38]

[34] APPrO written argument, para 3
[35] APPrO written argument, para 25
[36] OEB staff written argument, p.7
[37] SEC oral argument, transcripts, v.4, p.95
[38] SEC oral argument, transcripts, v.4, p.105-106

B. Absence of out-of-market payments to DR Resources

As discussed in section 3, in addition to the payments that generators receive for the energy they supply, there are also some out-of-market 'make whole' payments that are currently available to some generators but not to DR Resources in the event of activation.[39]

AMPCO

During the oral hearing, AMPCO questioned witnesses about the GCG program, and about past IESO and Ontario Power Authority programs that provided compensation for activation for DR Resources. It argued that DR Resources are at a competitive disadvantage in the TCA relative to generation resources because they do not have access to such out-of-market compensation.[40]

AMPCO noted, if the OEB finds the Amendments create a TCA that is discriminatory against DR Resources, "it is not up to the Board to fix that problem. It is up to the IESO". AMPCO added that the IESO has already done this in respect of out-of-market test and emergency activations, where the IESO determined compensation for DR Resources was appropriate. There is therefore no bar to the IESO implementing activation payments in relation to DR Resources, as an alternative to energy payments, if appropriate.[41]

IESO

The IESO submitted that the evidence before the OEB is that it is entirely within DR Resources' control to manage the probability or risk of activation by including economic activation costs in their energy market bids; and if they do this, the risk and associated cost of being activated is remote and immaterial.[42]

The IESO further argued that, where there are costs caused by uneconomic activations of DR Resources due to testing, the IESO has a program that is similar to those available to generators in that it also provides for out-of-market compensation. The IESO noted those are the only costs that DR Resources are exposed to that they cannot avoid through their energy market bids and the only place to put them was in their capacity auction bid.[43]

---

[39] KCLP oral argument, transcripts, v.4, p.119-120. KCLP discusses two generator cost guarantee programs introduced by the IESO: the real-time generation cost guarantee program in 2003 and the day-ahead cost guarantee program in 2006.
[40] AMPCO written argument, paras 5-7
[41] AMPCO oral reply argument, transcripts, v.5, p.20
[42] IESO written argument, paras 20-21, and the evidence of IESO's witnesses, transcripts v.3, p.23-24
[43] IESO oral argument, transcripts, v.4, p.165

KCLP

KCLP noted that the GCG programs were created to address a deficiency in the energy markets to provide assurance to certain generators that had long start-up times. In order to minimize potential losses, they avoided starting up unless they could cover all of their costs. The result of the introduction of the GCG program was that generators no longer had to build these costs into their energy market offers and, as a result, could avoid those potential losses.[44]

KCLP's witness, Mr. Windsor, stated that the GCG program guarantees recovery of about 10% to 15% of the overall variable costs associated with running the generation unit for a typical period of time.[45]

OEB Staff

OEB staff noted that both experts in this proceeding indicated that DR Resources can incur start-up costs that are akin to those recovered by eligible generators under the GCG program.[46]

OEB staff submitted that determining whether there is unjust discrimination absent a mechanism through which DR Resources can recover activation costs depends on the OEB's assessment of the similarity of circumstances between GCG-eligible generators and DR Resources.

OEB staff agreed that both DR and generation resources can provide capacity to the market on a functionally equivalent basis, and did not dispute that each resource type may incur certain costs, including start-up and variable costs. OEB staff noted that, while it is conceivable that some start-up costs could be incurred by some DR Resources, there was no evidence on the record that any DR Resource faces physical or operational constraints of a similar magnitude to those faced by GCG-eligible generators.[47]

OEB staff questioned IESO's suggestion that they have other "similar programs" to the GCG for DR Resources where the example provided was payments for out-of-market activations involving Hourly Demand Response resources. OEB staff noted that such payments are not similar in nature because they are "make-whole" payments for "testing" required by the IESO, rather than payments related to participating in the market.[48]

[44] KCLP oral argument, transcripts, v.4, p.119-120
[45] Transcripts, v.2, p.29
[46] OEB staff written argument, p.8
[47] OEB staff written argument, p.10
[48] OEB staff written argument, p.9

Does FERC Order 745 provide any guidance for Ontario?

AMPCO's application referenced, among other things, the U.S. Federal Energy Regulatory Commission (FERC) Order 745, issued in 2011.[49] This Order established that DR Resources participating in organized wholesale energy markets would be compensated through the payment of the locational marginal price for curtailing their load if dispatched. In the Order, FERC concluded that it would be "unjust" and "unreasonable" to not pay DR Resources the same energy price as generators due to their functional equivalence in relation to balancing supply and demand. FERC Order 745 stated the following:

> *...when a demand response resource has the capability to balance supply and demand as an alternative to a generation resource ... payment by an RTO or ISO of compensation other than the [locational marginal price] is unjust and unreasonable. ... As stated in the NOPR, we believe that paying demand response resources the LMP will compensate those resources in a manner that reflects the marginal value of the resource to each RTO and ISO.*[50]

While AMPCO stated that the FERC Order neither should nor could be directly applied to the Ontario context, it submitted that the Order, given the hearing process that preceded it, could nevertheless provide a starting point for determining appropriate treatment for DR Resources.[51]

There was also general agreement, including among both experts (Mr. Goulding and Dr. Rivard), that FERC's actual approach in Order 745 involving paying the full locational marginal price to DR Resources that passed a net benefit test was not applicable to Ontario. Beyond the basic matter of FERC not having jurisdiction in Ontario, an additional practical reason for that is the Global Adjustment (GA), which is unique to Ontario.

Also, as discussed in LEI's report on DR programs in selected US markets (LEI Report)[52], a primary goal of FERC Order 745 was to address barriers to DR that FERC identified, such as the lack of a direct connection between wholesale market prices and fixed retail prices, and a lack of dynamic retail prices (i.e., retail prices that change as the marginal wholesale costs change). Due to this disconnect, "customers do not have the ability to respond to the often volatile price changes in the wholesale market and demonstrate the need for including demand response as part of wholesale market

[49] AMPCO Application, paras 36-43
[50] AMPCO written argument, para 37
[51] Transcripts, v.1, p.33-35
[52] LEI Report, 'Demand response programs in selected US markets', filed November 8, 2019

design." [53] Ontario does not have the same disconnect between wholesale market prices and retail prices.

Findings

While useful as an example of an approach taken in another jurisdiction, the OEB finds that FERC Order 745 is not relevant to the determination of the issues in this proceeding given the differences in the markets.

Frequency of Dispatch/Activation

a) What is the risk of activation?

b) To what extent is the historical experience regarding activation indicative of future expectations?

c) Can DR Resources adequately address this activation risk?

AMPCO

a) AMPCO noted that the costs associated with activation (i.e., curtailment) are specific to each individual DR Resource in the auction based on a number of business and operational factors; no two DR Resources are likely to have the same characteristics, inputs or outcomes. As a result, the risk of activation differs across DR Resources.[54]

b) AMPCO argued that, as DR-related technologies change, so might the frequency of investment by DR Resources. Consequently, the past under one set of rules and conditions cannot be assumed to necessarily predict the future under another, more equitable set of rules.[55]

c) AMPCO responded to IESO's position that there is no activation risk for DR Resources that cannot be managed through their energy bids. AMPCO noted that the costs at risk are the costs of activation, and the only way for DR Resources to cover that risk is through their capacity offers because they are not getting any other payments upon activation. Generators recover their activation costs through their energy payments, so they do not have to manage that risk through their capacity offers. AMPCO added that despite what the IESO says, there is no bidding strategy that can protect DR Resources from this risk beyond including that risk in their capacity offers. In the TCA, there is only a

[53] LEI Report, p.14
[54] AMPCO Response to OEB staff IR #1
[55] AMPCO written argument, paras 13-17

protective bidding strategy for DR Resources and that is if they receive energy payments, so that the cost of activation would not need to be reflected in their capacity offers.[56] DR Resources were able to manage that risk, without energy payments, in the DRA by reflecting the activation costs in their capacity offers because they were all exposed to the same risk (i.e., no unfair competitive disadvantage).[57]

IESO

a) The IESO noted that DR Resources have been economically activated in the energy market in very limited circumstances since the DRA was launched in 2015 – once in 2019 for Hourly Demand Response resources, while dispatchable loads have been dispatched less than 1% of the time.[58] This is likely due to the relatively high prices at which DR Resources bid into the energy market.[59] The IESO also noted that it has not conducted any analysis to assess the reasons for the historical decline – from 244 to 64 – in annual DR activations since the DRA was created. [60]

b) The IESO stated that "based only on historical bids of dispatchable loads, the IESO would expect little change to the frequency of economic activations for DR resources in 2021, 2022, or 2023." [61]

c) According to the IESO, all of the activation costs that AMPCO alleges DR Resources are exposed to, when they are activated in the energy market, can be included in their energy market bids; in other words, they do not need to be included in their capacity offers in the TCA.[62] In the IESO's view, DR Resources are capable of entirely managing that risk by bidding high enough into the energy market, so that they do not get called upon and avoid incurring activation costs. It does not matter what the costs are called – value of lost load, activation costs, start-up costs, shutdown costs – that a DR Resource is potentially exposed to when activated in the energy market, they can manage those costs through their energy market bids.[63] IESO argued that AMPCO's claim is an abstract, theoretical claim of discrimination.[64]

[56] AMPCO oral reply argument, transcripts, v.5, p.16
[57] AMPCO oral reply argument, transcripts, v.5, p.5-12
[58] IESO Evidence, paras 36-39
[59] During this period, the HOEP has averaged about $25/MWh, while dispatchable load bid prices have averaged about $1,500/MWh and HDR bid prices have averaged about $1,700/MWh.
[60] IESO Response to OEB staff Supplemental IR #14
[61] IESO Response to OEB staff Supplemental IR #14
[62] Transcripts, v.5, p.13
[63] Transcripts, v.5, p.28-29
[64] Transcripts, v.5, p.31

KCLP

KCLP argued that the IESO-administered markets provide market participants a fair degree of flexibility, in terms of deciding how they bid into those markets and deciding how they choose to compete in those markets. The fact that one market participant may choose to adopt what it called “an irrational or uncompetitive economic bidding strategy” and consequently lose out in a competitive market is not sufficient grounds to justify a finding of unjust economic discrimination, particularly if it can be shown that that market participant could have avoided the problem by adopting a different bidding strategy.[65]

SEC

SEC referenced IESO's evidence that DR Resource activations are expected to remain infrequent in the future and submitted that, if that is the case, then there would be an extremely low need for a DR Resource to build anything into its capacity offer to recover the costs of activation. The test is not whether there is no risk that there will be activation, but that there has to be some meaningful risk which would have a meaningful impact on costs and a meaningful impact on the bids that DR Resources would make into the TCA. SEC therefore noted that, on the basis of the IESO’s evidence, there cannot be said to be any discrimination between DR Resources and generators in the TCA.[66]

Findings

The OEB finds that the two classes of market participants, generators and DR Resources, will be treated differently if they successfully bid in the TCA. There was little disagreement in the proceeding that differences in treatment result from the different payments that different resources are eligible to receive if activated. These include energy payments and out-of-market payments such as the GCG. In this way, there at least appears to be discrimination.

In theory, these differences in treatment could result in unjust economic discrimination as the DR Resources, being ineligible for those payments, may have to substantially lower their offers to uneconomic levels if they wish to successfully compete in the TCA. For DR Resources, the costs associated with activation will not be recoverable in the current market.

[65] KCLP oral argument, transcripts, v.4, p.117
[66] SEC oral argument, transcripts, v.4, p.97

Is there sufficient evidence to determine if there will be economic discrimination? Is there sufficient evidence to determine that any economic discrimination will be "unjust"?

AMPCO

AMPCO acknowledged that it must demonstrate the basis for the OEB to find that the Amendments result in unjust discrimination or are contrary to the objectives of the legislation[67] but it took the position that extensive economic analysis is not necessary for AMPCO to discharge its burden.[68]

AMPCO argued that the test for unjust discrimination is a qualitative, rather than quantitative test and that "functional equivalence, different compensation, lack of economic justification; that is, the 'unjust' component of the 'unjust discrimination' test under section 33 of the Act".[69]

It was AMPCO's evidence that DR Resources incur real costs to curtail their load, and that these costs are beyond the cost of lost production.[70] AMPCO stated that the cost elements associated with curtailment are specific to each individual participant based on a number of business and operational factors and no two participants are likely to have the same characteristics, inputs or outcomes.[71] In testimony, AMPCO cited an example from the steel industry, but without quantifying any costs.[72]

IESO

IESO argued that the evidence before the OEB does not support energy payments for DR Resources. AMPCO has not provided any expert evidence to the contrary. Other than referencing FERC's Order 745 and its "net benefits" test, AMPCO has not provided any evidence to show that the absence of energy payments for DR Resources in Ontario is unjust.[73]

KCLP

KCLP argued that AMPCO has provided insufficient evidence to substantiate its allegation of discrimination and to fulfil this prong of the legal test. There is no direct

[67] AMPCO oral argument, transcripts, v.4, p.15
[68] AMPCO oral argument, transcripts, v.4, p.24
[69] AMPCO oral argument, transcripts, v.4, p.11-12
[70] AMPCO oral argument, transcripts, v.4, p.27
[71] AMPCO Response to OEB staff IR#1(a)
[72] Transcripts, v.1, p.16
[73] IESO written argument, paras 16-17

evidence from any AMPCO member or other DR Resource that they would be unjustly discriminated against.[74]

APPrO

APPrO argued that AMPCO's evidence in this proceeding is deficient and falls short of discharging the burden of demonstrating that the Amendments unjustly discriminate against DR Resources. AMPCO has not advanced an analysis, study, or report that sets out the potential economic impacts of the Amendments on its members. The OEB should afford AMPCO's evidence the commensurate evidentiary value for what it is; that is, a theoretical concern from a non-market participant that is unsupported by experience, facts or data.[75]

SEC

SEC said that it had no reason to doubt the steel manufacturer example that AMPCO provided with respect to incremental activation costs. However, there are a number of uncertainties. There is a broad array of DR Resources and it is not clear how relevant that type of incremental activation cost is in relation to other types of DR Resources and/or what the overall magnitude is. There was also evidence on Hourly Demand Response resources in this proceeding, but it is uncertain if they have any incremental costs.[76] Unfortunately, neither AMPCO, nor probably more importantly, the IESO provided any impartial analysis regarding the actual impact on customers of providing energy payments to DR Resources.[77]

OEB Staff

OEB staff noted that, beyond anecdotal examples, there is no evidence on the record regarding the quantum and types of costs DR Resources may incur upon activation. Furthermore, there was little evidence on how widespread these costs are across the diverse group of DR Resources.[78]

Findings

The OEB finds that there is insufficient evidence to make a finding that the Amendments will result in unjust discrimination.

[74] KCLP written argument, para 40
[75] APPrO written argument, paras 10, 12, 14
[76] SEC oral argument, transcripts, v.4, p.91-92
[77] SEC oral argument, transcripts, v.4, p.100
[78] OEB staff written argument, p.6

At Section 4 of this Decision, in describing the test to be applied to assess whether there is unjust discrimination, the OEB identified three elements: (i) there must be evidence of discrimination, in the form of different treatment; (ii) it must be shown that the different treatment is being applied to market participants despite an absence of material and relevant differences in their circumstances; and (iii) the economic impact of the different treatment must be quantified – it cannot be purely qualitative.

In the preceding sections, the OEB found that there is no question that different resources are treated differently, in the form of differences in eligibility for payments. For example, certain generators are eligible for activation payments and start-up costs as part of the GCG program. These payments are specific to the circumstances of each generator. DR Resources do not have access to these payments.

On the question of differences in circumstances between generation and DR Resources, the evidence before the OEB is that both generators and DR Resources incur activation costs, and that these costs vary among members of each of these two classes of market participants. Generation and DR Resources are functionally equivalent in balancing supply and demand in the energy market. Theoretically, there are no relevant differences in their circumstances.

On the third element of demonstration of unjust discrimination being the quantification of the economic impact, there was no evidence presented by any party on the range of costs incurred by any of these market participants. The only example of costs that might be incurred by any of AMPCO's members was that of an unidentified steel manufacturer. Even then, there was no evidence of what the costs might actually be. The absence of quantitative evidence on costs that different parties incur does not permit the OEB to conclude with certainty whether the circumstances between generators and DR Resources are in fact similar or different, and whether, as a consequence, different treatment could constitute unjust discrimination. In addition, the experience to date under the DRA indicated that there has been very limited activation of DR Resources, which suggests that there could have been very limited economic impact on the DR Resources. However, there was no data on the financial or economic cost to DR Resources or a forecast as to the frequency of activation over the next decade. Absent this information, the extent of the economic impact to DR Resources cannot be estimated.

Given the insufficiency of evidence, as described above, the OEB has no basis on which to make a positive finding of unjust discrimination and return the Amendments to the IESO for reconsideration.

The OEB is cognizant of AMPCO's members' reticence to share their economic data with each other, and other competitors. That said, there are methods by which this information

could be shared with the OEB without compromising the confidentiality of any individual market participant's information.[79]

Could adjustments be made to the energy market rules or the capacity market rules to address the activation issue?

While the OEB has no authority in this proceeding to require the IESO to make any changes to any of its market rules, and will make no findings on the appropriateness of any particular approach, there was considerable discussion about alternatives to the current payment structure in the context of bid activation.

The major threads of discussion on this issue related either to the eligibility for payments to DR Resources upon dispatch, the expansion of out-of-market provisions, or alternative approaches to the design of bids in the energy market.

AMPCO

While AMPCO has advocated for an energy payment (a payment to DR Resources upon activation equal to the prevailing energy price), its final argument in this proceeding noted that an energy payment is not the only way to rectify the alleged discrimination.

AMPCO noted that "there are several examples of historical programs in which DR Resources were provided with administratively set (rather than market determined) activation payments".[80] AMPCO also noted that, unlike energy payments to compensate DR Resources, such alternative mechanisms would involve changes to the market rules that would not result in disrupting the initial market design.[81] AMPCO urged the OEB, in referring the Amendments back to the IESO, to provide guidance to the effect that the IESO should provide a mechanism through which DR Resources will have a reasonable opportunity to recover their incremental costs of activation.[82]

OEB Staff and KCLP

As noted above, OEB staff and KCLP submitted that an energy payment made to DR Resources in order to compensate for variable costs of activation would constitute a

[79] The OEB's *Rules of Practice and Procedure* and its *Practice Direction on Confidential Filings* make provision for the confidential treatment of information in appropriate cases. In assessing requests for confidential treatment, the OEB considers (among other things) whether the information is commercially sensitive and the potential harm that could result from disclosure in terms of a person's competitive position.
[80] AMPCO written argument, para 27
[81] AMPCO oral reply argument, transcripts, v.5, p.20
[82] AMPCO written argument, para 43

double payment for the reduction in demand since it would provide revenue in addition to avoided costs.[83]

Dr. Rivard noted during cross examination that, if DR Resources have to raise their energy bid price above VOLL in order to reflect one-time costs of activation, it is not ideal from a market design standpoint.[84] He also noted that there is a potential that the DR Resource is at disadvantage in the sense that it is not offered exactly the same kind of guarantee for what is a same cost.[85]

In response to a question from the OEB during the oral hearing regarding whether all types of resources would need to get the same payment for energy (as well as capacity) for it to be a fair competitive market, Mr. Goulding explained that one might conclude that it is fair if all resources get the same energy payment (market clearing price) for the same service. However, the avoided cost associated with a DR Resource introduces a challenge, since that, itself, may or may not be considered a form of energy payment. Mr. Goulding expressed the view that it would be fair if the DR Resource is compensated at its short run marginal cost when activated. While doing so would require a host of new market rules, it gets away from the double payment issue.[86]

Observations

The OEB acknowledges that the IESO has a study underway to determine what, if any, payments should be made to DR Resources. It is beyond the scope of this proceeding for the OEB to comment on this study or any potential changes that may arise from it.

However, the OEB believes some general observations might be helpful. When considering market changes, the IESO should examine the total costs and compensation available to capacity market participants, whether that compensation is in the capacity market or the energy market, and whether that compensation is an out-of-market payment or some form of energy payment. The priority is to ensure that there is no unjust discrimination for or against any class of market participants. This is particularly relevant as the capacity market continues to expand by adding other types of resources.

[83] OEB staff written argument, p.7
[84] Transcripts, v.2, p.141
[85] Transcripts, v.2, p.114-115
[86] Transcripts, v.1, p.164-165

6 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. The Application by the Association of Major Power Consumers in Ontario for an order under section 33 of the *Electricity Act, 1998* revoking the market rule amendments identified as MR-00439-R00 to –R05: "Transitional Capacity Auction" and referring the amendments back to the IESO for further consideration is denied.

2. The stay of the operation of the market rule amendments identified as MR-00439 -R00 to –R05: "Transitional Capacity Auction", as ordered by the Decision and Order of the OEB dated November 25, 2019, is lifted.

3. Parties eligible for an award of costs shall submit their cost claims by February 6, 2020. A copy of the cost claim must be filed with the OEB and one copy is to be served on the IESO. The cost claims must comply with section 10 of the OEB's *Practice Direction on Cost Awards*.

4. The IESO will have until February 13, 2020 to object to any aspect of the costs claimed. A copy of the objection must be filed with the OEB and one copy must be served on the party against whose claim the objection is being made.

5. A party whose cost claim was objected to will have until February 20, 2020 to make a reply submission as to why its cost claim should be allowed. A copy of the submission must be filed with the OEB and one copy is to be served on the IESO.

All materials filed with the OEB must quote the file number, EB-2019-0242, be made in a searchable/unrestricted PDF format and sent electronically through the OEB's web portal at https://pes.ontarioenergyboard.ca/eservice. Two paper copies must also be filed at the OEB's address provided below. Filings must clearly state the sender's name, postal address and telephone number, fax number and email address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at https://www.oeb.ca/industry. If the web portal is not available parties may email their documents to the address below. Those who do not have computer access are required to file seven paper copies.

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.

With respect to distribution lists for all electronic correspondence and materials related to this proceeding, parties must include the Case Manager, Michael Bell at Michael.Bell@oeb.ca and OEB Counsel, Ljuba Djurdjevic at Ljuba.Djurdjevic@oeb.ca.

ADDRESS

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4
Attention: Board Secretary

Email: boardsec@oeb.ca

Tel: 1-888-632-6273 (Toll free)

Fax: 416-440-7656

DATED at Toronto January 23, 2020

ONTARIO ENERGY BOARD

Original Signed By

Christine E. Long
Registrar and Board Secretary

TAB 8

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

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 constrained 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 unconstrained 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

TAB 9

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



Monitoring Report on the IESO-Administered Electricity Markets

for the period from
May 2015 – October 2015

November 2016

PUBLIC

Page Left Blank Intentionally

Table of Contents

Executive Summary 1
Matters to Report in the Ontario Electricity Marketplace 1
Market Outcomes 3
Chapter 1: Market Outcomes 1
1 Pricing 1
2 Demand 48
3 Supply 51
4 Imports, Exports and Net Exports 57
Chapter 2: Analysis of Anomalous Market Outcomes 64
1 Introduction 64
2 Anomalous OR and HOEP Events 66
2.1 Examples of Large Variations Leading to Scarcity of Dispatchable Capacity 69
2.2 Highest HOEP and OR payments During Wind Production Shortfall 69
2.3 High HOEP and OR Payments 71
2.4 Differences Between Forecast and Actual Supply and Demand 73
2.5 Forecast errors put more strain on OR supply 75
2.6 Reduction in Total Offers of OR 76
2.7 Control Action Operating Reserves are Scheduled More Frequently 77
2.8 Other North American ISOs are Facing Similar Challenges 79
2.9 Market Design Changes are needed to Keep Pace 81
3 Negative HOEPs 83
4 Anomalous CMSC Payments 83
5 Anomalous IOG Payments 83
6 Five Highest Daily DA-PCG Payment Totals 84
7 High RT-GCG Payments 84
Chapter 3: Matters to Report in the Ontario Electricity Marketplace 86
1 Introduction 86
2 Panel Investigations 86
3 New Matters 86
3.1 Inefficiency on Ontario's Interties Induced by the Two-Schedule System 86
3.2 A Review of the IESO's Real-Time Cost Guarantee Program 101
3.3 Appendix A 130
Chapter 4: Future Market Developments and Panel Recommendations 131
1 Future Development of the Market 131
1.1 Market Renewal 131
1.2 Enabling System Flexibility 133
2 Past Panel Recommendations and Investigations 133
2.1 Limiting CMSC Payments During Ramp-Down 133
2.2 IESO Concludes its Investigation into Abitibi-Consolidated Company of Canada and Bowater Canadian Forest Products Inc. 134
3 Recommendations in this Report 135

List of Tables

Table 1-1: Average Effective Price by Consumer Class 1
Table 1-2: Factors Contributing to Differences between One-Hour Ahead Pre-Dispatch Prices and Real-Time Prices 20
Table 1-3: Monthly Average Hourly Electricity Prices –Ontario and Surrounding Jurisdictions 37
Table 1-4: Average Long-Term Transmission Right Auction Prices by Interface and Direction 43
Table 1-5: Average Short-Term Transmission Right Auction Prices by Interface and Direction 44
Table 1-6: Average Monthly Export Failures by Interface Group and Cause 60
Table 1-7: Average Monthly Import Failures by Interface Group and Cause 62
Table 2-1: Summary of Anomalous Events during Summer Periods in 2013, 2014 and 2015 64
Table 2-2: Anomalous HOEP and OR Payment Events May 1, 2015 to October 31, 2015 66
Table 2-3: Hourly Average and Maximum Wind Production and Shortfalls 68
Table 2-4: OR Requirement Shortfalls January 1, 2012– December 31, 2015 (Number of intervals) 69
Table 2-5: Market Data Tuesday May 5, HE 16, 2015(MW and $) 70
Table 2-6: Market Data Friday October 2, HE 9, 2015 (MW and $) 72
Table 2-7: Number of Intervals with CAOR Schedules 78
Table 2-8: Anomalous DA-PCG Payments (daily) Five Highest Daily DA-PCG Payments 84
Table 2-9: Highest RT-GCG Payments May – October 2015 85
Table 3-1: Profit (Loss) During MGBRT Hours 122
Table 3-2: Comparison of Revenue Offset Methodology 123
Table 3-3: Annual RT-GCG Savings……. 127
Table 3-4: Assessing the RT-GCG Program 129

List of Figures

Figure 1-1: Monthly Average Effective Electricity Price and System Costs 5
Figure 1-2a: Average Effective Electricity Commodity Price for Direct Class A Consumers by Component 8
Figure 1-2b: Average Effective Electricity Commodity Price for Class B & Embedded Class A Consumers by Component 9
Figure 1-3: Monthly (Simple) Average Hourly Ontario Energy Price (HOEP) 10
Figure 1-4: Natural Gas Price and On-peak Hourly Ontario Energy Price 11
Figure 1-5: Frequency Distribution of Hourly Ontario Energy Price 13
Figure 1-6: Share of Resource Type setting Real-Time Market Clearing Price 15
Figure 1-7: Share of Resource type setting the One-Hour Ahead Pre-Dispatch Market Clearing Price 16
Figure 1-8: Difference between the HOEP and the One-Hour Ahead Pre-Dispatch Price 18
Figure 1-9: Difference between the HOEP and the Three-Hour Ahead Pre-Dispatch Price 22
Figure 1-10: Monthly Global Adjustment by Components 23
Figure 1-11: Total Hourly Uplift Charge By Component and Month 25
Figure 1-12: Total Monthly Uplift Charge by Component and Month 27
Figure 1-13: Average Monthly Operating Reserve Prices, by Category 29
Figure 1-14: Average Internal Nodal Prices by Zone 31
Figure 1-15: Import Congestion by Interface Group 34
Figure 1-16: Export Congestion by Interface Group 35
Figure 1-17: Import Congestion Rent & Transmission Rights Payouts by Interface Group 39
Figure 1-18: Export Congestion Rent & TR Payouts by Interface Group 42
Figure 1-19: Transmission Rights Clearing Account 47
Figure 1-20: Monthly Ontario Energy Demand 49
Figure 1-21: Monthly Total Energy Withdrawals, Distributors and Wholesale Loads 50
Figure 1-22: Resources Scheduled in the Real-Time Market (Unconstrained) Schedule 52
Figure 1-23: Average Hourly Operating Reserve Scheduled by Resource or Transaction Type 54
Figure 1-24: Unavailable Generation Relative to Installed Capacity 55
Figure 1-25: Total Monthly Imports, Exports & Net Exports 57
Figure 1-26: Net Exports by Interface Group 59
Figure 2-1: OR Schedules and 10S Price Tuesday May 5, HE 16, 2015 71
Figure 2-2: OR Schedules and 10S Price Friday October 2, HE 9 2015 73
Figure 2-3: Anomalous HOEP and OR Payment Events 74
Figure 2-4: OR Market Participant's Market Share by Scheduled MWs 76
Figure 2-5: Total OR Offers 77
Figure 3-1: Example of Trade between Ontario and New York 89
Figure 3-2: Example of Excessive Net Exports to New York 90
Figure 3-3: Example of Insufficient Net Exports to New York 91
Figure 3-4: Net Exports and the New York – Ontario Cost Spread 95
Figure 3-5: Distribution of the Wedge between Price and Cost at the New York Intertie 97
Figure 3-6: Net Exports, New York – Ontario Cost Spread and Ontario Cost-Price Spread 99
Figure 3-1: Average RT-GCG Payments and Dawn Daily Gas Price 108
Figure 3-A1 : Example of 'Choosing' MGBRT Period August 10, 2015 130

Executive Summary

Matters to Report in the Ontario Electricity Marketplace

Review of Generation Cost Guarantee Program

In this report the Panel provides a more comprehensive overview of issues associated with the Independent Electricity System Operator's (the IESO) Real-Time Generation Cost Guarantee (RT-GCG) program under which guarantees are paid to certain gas-fired generators for start-up and operations costs. This program has been the subject of long-standing interest and past Panel commentary, and has recently been under review in an IESO stakeholder engagement. The Panel actively participated in that stakeholder engagement.

At the most fundamental level, the Panel questions the extent to which the RT-GCG program is truly necessary to serve a reliability purpose. The Panel's analysis suggests that starts under the program support reliability in only a small number of hours each year. The IESO has not provided any analysis of the continued need for the program, although the Panel has recommended on more than one occasion that such an analysis be done.

The Panel acknowledges that the IESO has to manage changing conditions between day-ahead and real-time. The Panel also acknowledges that the IESO is deferring a comprehensive overhaul of the RT-GCG program in favour of a longer-term solution in the form of an enhanced intra-day unit commitment program. However, by the IESO's own admission that solution is several years away. While the Panel is supportive of a comprehensive overhaul of the program, it is unclear to the Panel why changes to the program that have the potential to save millions in costs should not be made now pending the implementation of the more enduring solution.

Two changes in particular appear to the Panel to be desirable in the near term. First, the Panel believes that there is no demonstrable need for the RT-GCG program to guarantee start-up operations and maintenance costs in order to achieve the objective of incenting generators to come online to support reliability. Second, in the Panel's view it is similarly unnecessary for a generator to recover all of its costs through revenues earned in the market and yet still receive a guarantee payment under the RT-GCG program. Changes to these two elements of the RT-GCG program alone would, by the Panel's estimation, reduce RT-GCG payments to generators by

approximately $40 million per year in the aggregate. These savings would ultimately avail to the benefit of Ontario ratepayers.

Recommendation 3-1

The Panel recommends that the IESO eliminate from the Real-time Generation Cost Guarantee program the guarantee associated with: (a) incremental operating costs for start-up and ramp to minimum loading point; and (b) incremental maintenance costs for start-up and ramp to minimum loading point.

Recommendation 3-2

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

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

Review of the Efficiency of Intertie Trading given Ontario's Two-Schedule System

This report contains the Panel's analysis of how Ontario's two-schedule, single price system is contributing to the inefficiency of intertie trading with Ontario's neighbours. Since the two-schedule system (prices and schedules are determined by two different algorithms) can create a difference between the price paid for energy and the cost of producing it, exports of power are inefficient when the price exporters pay is less than the cost of producing power.

The Panel has assessed the extent to which inefficient trades are created as a by-product of the two-schedule system, finding that there are opportunities to reduce inefficient trade by, for example, pricing intertie transactions at the cost of production at the intertie. The IESO has initiated work on a Market Renewal stakeholder engagement, in which it plans to examine opportunities to improve efficiency by replacing the two-schedule system, including through the introduction of locational marginal pricing. The Panel strongly supports this work.

Market Outcomes

The Panel's review and analysis of market outcomes covers the period from May 1, 2015 to October 31, 2015 (the Current Reporting Period).

High HOEPs and Uplift Payments

In the Current Reporting Period there were nine instances where the Hourly Ontario Energy Price (HOEP) was above $200/MWh and 15 instances where Operating Reserve (OR) payments in an hour were above $100,000. All but one of the high OR payments, and all of the high HOEP events, were associated with shortages of dispatchable capacity resulting from errors in the forecast of production from renewable resources.

The forecast errors associated with these events arose when production from renewable resources was less than forecast, a situation which requires other resources to respond on short notice to provide additional energy. Since these forecast errors only emerge in real-time, the IESO must often dispatch higher cost, fast responding resources to make up the shortfall. Frequently the resources which are available to respond are those which have been scheduled to provide operating reserve (that is, capacity that is held on standby to ensure reliability in the event of a large generator or transmission line going offline). When the resources scheduled for OR are dispatched to provide energy in response to forecast errors, there may not be enough other capacity online to meet both the energy demand and the OR requirement. In some cases the IESO has experienced an OR shortfall, in which case both energy and OR prices increase to reflect the scarcity of dispatchable capacity.

The IESO has launched a stakeholder engagement to develop solutions that will provide additional real-time flexibility when forecast errors require a response within one hour or less. The IESO has articulated principles by which it will evaluate proposed solutions, including transparency, cost-effectiveness, and creating an enduring solution. One option that would help to mitigate the impact of forecast errors is more frequent intertie scheduling. Currently, intertie schedules are fixed for one hour. Allowing intertie schedules to adjust within the hour would give the IESO greater dispatch flexibility to manage forecast errors. As Ontario is frequently a net exporter, reducing exports when the IESO experiences a scarcity of dispatchable capacity

would help the IESO respond to forecast errors that otherwise require the dispatch of more expensive resources.

An additional issue the Panel has identified is the real-time pricing of operating reserve, which the Panel believes could be improved to more transparently reflect the increasing value of operating reserve as more OR resources are needed. The IESO offers Control Action Operating Reserve (CAOR) into the OR market in large blocks, which can mask the increasing value of OR as more CAOR is scheduled. The Panel has made one recommendation to the IESO to consider whether the transparency and effectiveness of OR price signals could be enhanced.

Recommendation 2-1

Given the number of recent changes in the operating reserve market, the Panel recommends that the IESO review whether the real-time operating reserve prices transparently reflect the value of operating reserve as more Control Action Operating Reserve capacity is scheduled, and whether changes to Control Action Operating Reserve offer quantities and prices could enhance the efficiency of the operating reserve market.

Demand and Supply Conditions

In 2015 Ontario electricity demand peaked for the third consecutive year in the winter, reaching total consumption of over 13.5 TWh over the month of January. In the Current Reporting Period, the peak in monthly demand occurred in July at 12.6 TWh.

408.5 MW of nameplate generating capacity was added to the grid over the Current Reporting Period, consisting of wind (308.5 MW) and solar (100 MW) resources. In addition, 237 MW of nameplate generating capacity was connected at the distribution level.

Market Prices and Effective Prices

In the Current Reporting Period, the average effective price increased to $60.00/MWh for Direct Class A consumers and to $104.93/MW for Class B & Embedded Class A consumers. The primary factor behind the higher average effective prices was an increase in the Global Adjustment (GA). Direct Class A consumers saw the average GA increase by over $8.00/MWh

while Class B & Embedded Class A consumers experienced an average GA increase of over $14.00/MWh.

The Current Reporting Period saw two of the three highest monthly effective electricity prices for Class B & Embedded Class A consumers since market opening, reaching $111.77/MWh in May and $110.19/MWh in June.

The Panel has previously identified a need to obtain more data on the consumption of Class A consumers embedded within distribution systems. This data is not currently in the hands of the Panel, the IESO or the Ontario Energy Board. Without this data, the Panel cannot accurately track the effective price paid by Class A consumers as whole, as a number of Class A consumers are embedded within distribution systems.

Generation connected at the distribution level is an increasingly important component of Ontario's power supply, yet there is little real-time data regarding supply from these facilities. The Panel has identified a similar need to obtain data on production from embedded generation resources. Embedded resources include variable generators (primarily wind and solar powered generators) that feed into the distribution system and behind-the-meter generators that satisfy on-site demand. These resources reduce the level of demand on the IESO-controlled grid, and without data on their production it is challenging to accurately track changes in demand for electricity. In addition, Class A consumers connected at either the transmission or distribution level have a strong incentive to reduce their peak demand by reducing consumption or through self-generation. The Panel will continue to explore options that may be available to enable the collection and analysis of real-time data on embedded Class A consumption and embedded generation.

Chapter 1: Market Outcomes

This chapter reports on outcomes in the IESO-administered markets for the period between May 1, 2015 and October 31, 2015 (the Current Reporting Period), with comparisons to the period between November 1, 2014 and April 30, 2015 (the Previous Reporting Period) and other periods where relevant.

1 Pricing

This section summarizes pricing in the IESO-administered markets, including the Hourly Ontario Energy Price (HOEP), the effective price (including the Global Adjustment and uplift charges), operating reserve prices, and transmission rights auction prices.

Table 1-1: Average Effective Price by Consumer Class November 2014- April 2015 & May 2015 – October 2015 ($/MWh)

Description:

Table 1-1 summarizes the average effective price[1] by consumer class for the Current Reporting Period and the Previous Reporting Period. The average effective price is the sum of the average HOEP, the average Global Adjustment (GA), and average uplift charges. Results are reported for three consumer groups: Class A consumers that are directly connected to the IESO-controlled grid (Direct Class A); Class A consumers that are connected at the distribution level (Embedded Class A) and Class B consumers (Class B & Embedded Class A);[2] and "All Consumers", which is provided for reference purposes and represents what the effective price would have been for all consumers but for the change in the methodology for allocating the GA that took effect in January 2011. Information pertaining to Embedded Class A consumers is aggregated with information pertaining to Class B consumers because information regarding hourly consumption by Embedded Class A consumers is not readily available. Accordingly, average effective price information pertaining to Class A consumers relates only to Direct Class A consumers.

[1] This price does not include delivery, regulatory or debt retirement charges.
[2] Aggregating Class B consumers with embedded Class A consumers has the effect of under-representing the average effective price paid by Class B consumers, as the lower prices paid by Embedded Class A consumers reduces the average.

Customer Class	Average HOEP ($/MWh)	Average Global Adjustment ($/MWh)	Average Uplift ($/MWh)	Average Effective Price ($/MWh)
Direct Class A – Current*	21.07	36.53	2.40	60.00
Direct Class A - Previous	25.96	28.17	2.54	56.68
Class B & Embedded Class A - Current	22.76	79.53	2.64	104.93
Class B & Embedded Class A - Previous	28.19	65.11	2.78	96.07
All Consumers - Current	22.56	74.38	2.61	99.56
All Consumers - Previous	27.94	60.97	2.74	91.66

*Current means the Current Reporting Period and Previous means the Previous Reporting Period.

Relevance:

In Ontario, the effective price a consumer pays for electricity depends on its consumer class. Consumers are divided into two groups for purposes of the allocation of the GA: Class A—consumers with an average peak demand between 3 MW and 5 MW[3] that fall within certain industrial classifications and consumers with consumption greater than 5 MW (these consumers, typically factories or other large industrial consumers, can be directly connected to the IESO-controlled grid or connected at the distribution level); and Class B—all other consumers (including, for example, all small commercial and residential consumers).[4] Since January 2011, the GA payable by a Class A consumer is determined based on their peak demand factor, which is the ratio of the consumer's electricity consumption during the five peak hours in a year relative to total consumption by all consumers in each of those hours. The GA payable by a Class B consumer is, and has always been, based on the consumer's consumption during the period.[5]

Many Class B consumers—those that use less than 250,000 kWh of electricity per year and some others—are eligible for the Regulated Price Plan (RPP) prices set by the Ontario Energy Board (OEB). They pay those prices unless they choose to enter into a contract with an electricity retailer (in which case they pay the contract price) or they opt out of the RPP. The commodity

[3] Effective July 1, 2015, Class A was expanded to include certain consumers with a peak demand greater than 3 MW but less than or equal to 5 MW. As this expansion occurred mid-reporting period, a weighted average of the calculation was used for the Current Reporting Period results.
[4] See Ontario Regulation 429/04 (Adjustments under Section 25.33 of the Act) made under the *Electricity Act, 1998*, available at: http://www.ontario.ca/laws/regulation/040429.
[5] For more information on the GA allocation methodology and its effect on each consumer class see the Panel's June 2013 Monitoring Report, pages 69-92, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2012-Oct2012_20130621.pdf

price payable by Class B consumers that are not eligible for the RPP or that opt out of the RPP depends on their meter. If they have an interval meter, they pay the HOEP. If they do not have an interval meter, they pay a weighted average HOEP based on the net system load profile in their distributor's service area. For consumers that are not on the RPP, the GA appears as a separate line item on their electricity bill. Since RPP prices include a forecast of the GA, the GA is not a separate item on RPP consumer bills.

The GA primarily recovers the cost of payments to contracted and regulated generating resources when market revenues are insufficient to cover their contracted or regulated rates.[6] The HOEP and the GA are inversely proportional, as the recovery of contract and regulated payments through the GA to generators generally increases if market revenues decrease. When market prices rise, the amount of the contract or regulated payments to be recovered through the GA declines.

In the Panel's April 2015 Monitoring Report,[7] the need to obtain hourly generation and consumption data was discussed, specifically pertaining to embedded generation, behind-the-meter generation and consumption by Embedded Class A consumers. This data is not currently in the hands of the Panel, the IESO or the OEB. The Panel noted that assessing the impacts of certain market changes is difficult, if not impossible, without this hourly generation and consumption data.

Specifically, without this data, the Panel cannot accurately track the effective price paid by Class A consumers as whole, as a number of Class A consumers are embedded within distribution systems. In addition, Class A consumers connected at either the transmission or distribution level have a strong incentive to reduce their peak demand by reducing consumption or through self-generation. The Panel is therefore also interested in ascertaining the impacts of the GA allocation methodology on Class A consumption patterns. Access to hourly data for embedded Class A consumers and behind-the-meter generation is required for these purposes.

[6] The costs associated with compensating loads under the IESO's demand response programs and administering various other conservation programs (such as the saveONenergy program) are also recovered through the GA. Additional information regarding the GA is available at: http://www.ieso.ca/Pages/Ontario%27s-Power-System/Electricity-Pricing-in-Ontario/Global-Adjustment.aspx

[7] For more information on this topic see pages 105-109 of the Panel's April 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2013-Apr2014_20150420.pdf

Generation connected at the distribution level is an increasingly important component of Ontario's power supply, yet there is little real-time data regarding supply from these facilities. The Panel has identified a need to obtain data on production from embedded generation resources. Embedded resources include variable generators (primarily wind and solar powered generators) that feed into the distribution system, and behind-the-meter generators that satisfy on-site demand. These resources reduce the level of demand on the IESO- controlled gird, and without data on their production it is challenging to accurately track changes in demand for electricity.

The Panel will continue to explore options that may be available to enable the collection and analysis of real-time data on embedded Class A consumption and embedded generation.

Commentary and Market Considerations:

The average effective price increased for both Direct Class A consumers and Class B & Embedded Class A consumers during the Current Reporting Period relative to the Previous Reporting Period and to the May to October period in 2014 (the Summer 2014 Period).[8] The average effective price for both consumer classes was approximately $11.00/MWh greater in the Current Reporting Period than in the Summer 2014 Period.[9]

The GA was the primary driver behind the increase in the effective price for both consumer classes; reductions in the average HOEP and the average uplift relative to the Previous Reporting Period were more than offset by increases in the average GA as also shown in Figures 1-2A and 1-2B.

Relative to the Previous Reporting Period, Direct Class A consumers saw the average GA increase by over $8.00/MWh while Class B & Embedded Class A consumers experienced an average GA increase of over $14.00/MWh. As illustrated in Figure 1-10 below, this increase is primarily attributable to increased payments to prescribed or contracted hydroelectric generators

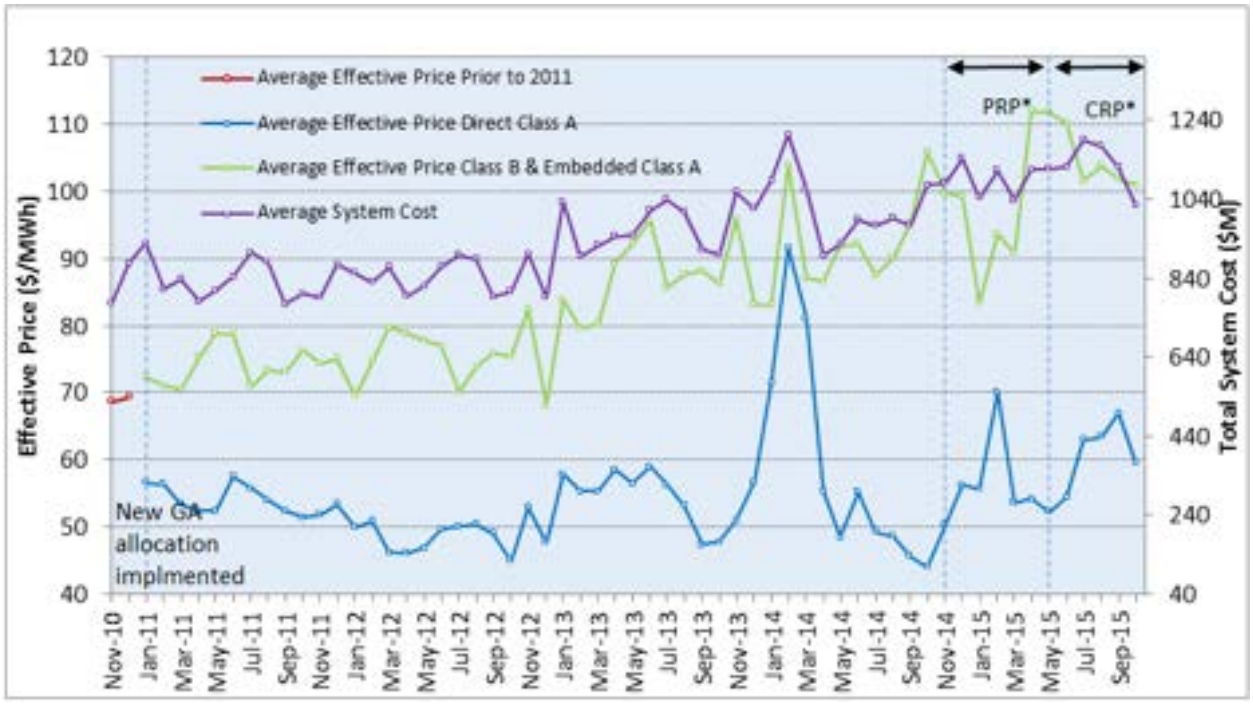
[8] The expansion of Class A as noted in the Description section above affects the comparability of prices between the Current and Previous Reporting Periods as some consumers that were formerly included in Class B price calculations have been included in the Class A price calculations as of July 1, 2015.
[9] For more information on the effective price in the Summer 2014 Period see pages 6-8 of the Panel's October 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2014-Oct2014_20151008.pdf

and renewable power contract holders, as well as increased payments under the IESO's conservation programs.

Figure 1-1: Monthly Average Effective Price and System Cost
November 2010 – October 2015
($/MWh & $)

Description:

Figure 1-1 plots the monthly average effective price for Direct Class A and Class B & Embedded Class A consumers, as well as the monthly average system cost[10] (System Cost), for the previous five years.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

This Figure highlights the changes in the effective price paid by each consumer class over the past five years, as well as the changes in System Cost.

Commentary and Market Considerations:

[10] The System Cost is the sum of the HOEP, the GA and the uplift charges paid by consumers in a given month. It does not account for any amounts paid by exporters.

The Current Reporting Period saw two of the three highest average monthly effective prices for Class B & Embedded Class A consumers (May at $111.77/ MWh and June at $110.19/ MWh), as well as two of the three highest average monthly System Cost (July at $1.189 billion and August at $1.175 billion), since market opening.

Within the Current Reporting Period, the two highest monthly effective prices for Class B & Embedded Class A consumers corresponded with the two lowest monthly effective prices for Direct Class A consumers. This highlights the continued trend that has been observed since January, 2011 when the GA allocation methodology was changed, shifting a greater portion of the GA to Class B consumers.

A lower HOEP results in the GA accounting for a greater portion of total System Cost. Class B consumers bear a greater portion of that total as Class A consumers are incented to reduce consumption during hours of peak system demand to minimize the amount of the GA they are charged. The GA avoided by Class A consumers is allocated to Class B consumers.

The HOEP was lowest during the first two months of the Current Reporting Period (see Figure 1-3 below). As the HOEP increased through the summer and into the fall, the Class B & Embedded Class A effective price decreased and the Direct Class A effective price increased. For Direct Class A consumers, September was the highest-priced month of the Current Reporting Period at an effective price of $66.92/MWh. This represents the fifth highest-priced month since the change in the GA allocation methodology in January 2011.

Total System Cost in the Current Reporting Period peaked in July and declined for three consecutive months beginning in August, most notably in September and October. The primary driver for the decline was a reduction in nuclear output relative to the Summer 2014 Period due to long term planned outages taken at one of Ontario's nuclear facilities beginning in early September and lasting through the end of October (see Figure 1-10 below). The contribution of nuclear facilities to the GA began to rise again in October. The resulting increase in the GA was offset by lower uplift and a lower HOEP in October (see Figure 1-2A and 1-2B below).

Figures 1-2A & 1-2B: Average Effective Price by Consumer Class and by Component

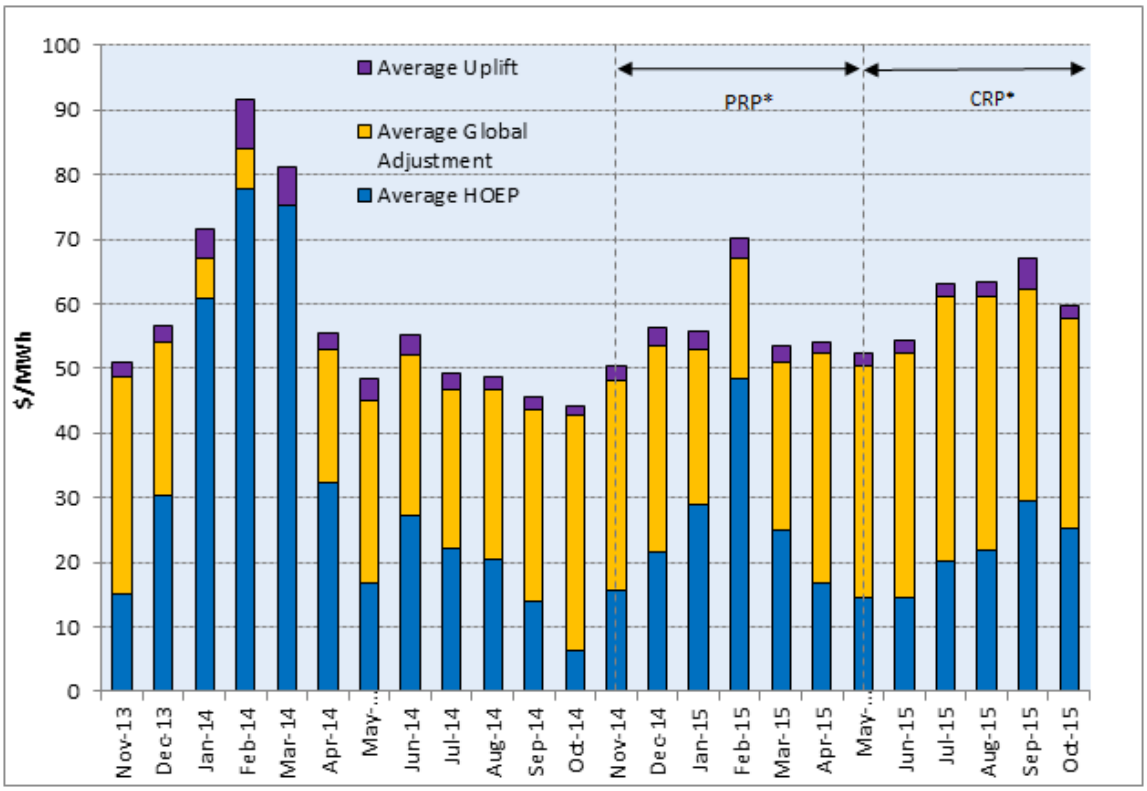
Description:

Figures 1-2A and 1-2B divide the monthly average effective price into its three components (average HOEP, average GA, and average uplift charges) for Direct Class A and Class B & Embedded Class A consumers for the previous two years.

As noted previously, the GA and the HOEP typically have an inverse relationship: when the HOEP decreases, the GA increases. The GA allocation methodology and the extent to which Class A consumers respond to that methodology are responsible for the significant difference in the average effective price paid by each consumer group. As the GA is charged to Class A consumers based on their share of peak load during the five hours with the highest total demand in a 12-month base period,[11] Class A consumers can substantially reduce their GA by reducing their consumption during these hours. When the average GA makes up an increasing portion of System Cost the average effective price paid by Class B consumers increases proportionately more than that paid by Class A consumers. This relationship is readily apparent in the Current Reporting Period.

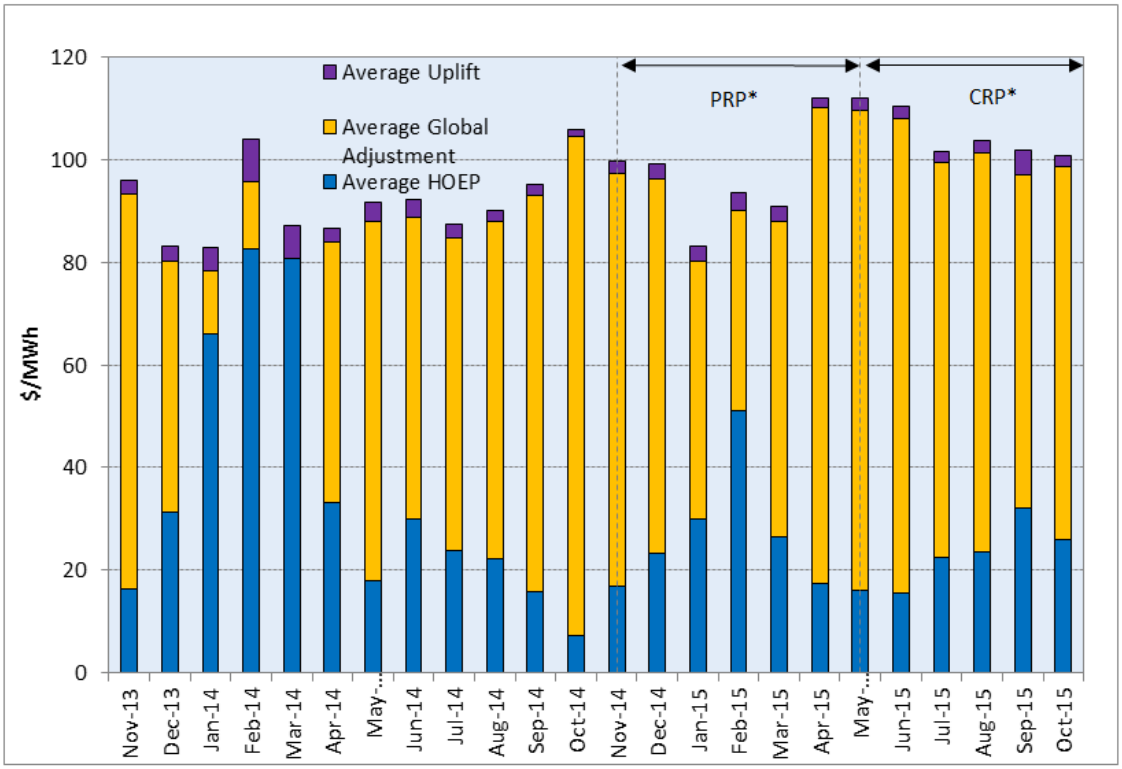
[11] Each base period runs from May 1 in one year to April 30 in the following year. The GA allocation for the Current Reporting Period is based on the base period from May 2014 to April 2015.

Figure 1-2A: Average Effective Price
for Direct Class A Consumers by Component
November 2013 – October 2015
($/MWh)



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Figure 1-2B: Average Effective Price for
Class B & Embedded Class A Consumers by Component
November 2013 – October 2015
($/MWh)



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

These two figures illustrate how changes in the individual components of the effective price affect the average effective price paid by each consumer group.

Commentary and Market Considerations:

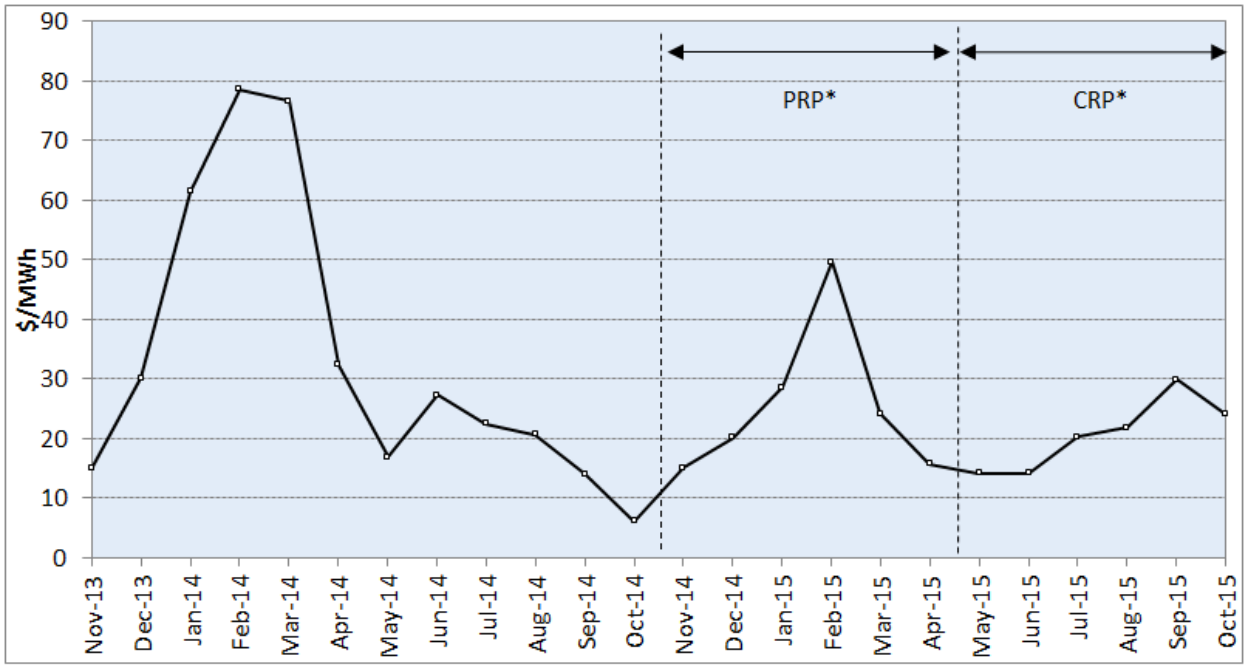
The impact of the change in the GA allocation methodology introduced in 2011 is evident in the Current Reporting Period; while the GA was the predominant component of the effective price paid by each consumer class, the average effective price for Class B and Embedded Class A consumers was nearly 75% higher than that of Class A consumers. As the HOEP rose from June through September, the effective price for Class B & Embedded Class A consumers exhibited a general downward trend, while the effective price for Direct Class A consumers exhibited an upward trend, save for October.

The Current Reporting Period marked the first time since market opening that the effective price for Class B & Embedded Class A consumers exceeded $100/MWh throughout the entire period. Class B & Embedded Class A consumers experienced the highest average effective price for a reporting period since market opening, while Direct Class A consumers experienced the second highest average effective price in any reporting period.

Figure 1-3: Monthly (Simple) Average HOEP
November 2013 – October 2015
($/MWh)

Description:

Figure 1-3 displays the simple monthly average HOEP for the previous two years.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

The HOEP is the market price for a given hour and is one component of the effective price paid by consumers. The HOEP is the simple average of the twelve Market Clearing Prices (MCPs) within the hour that are set every five minutes by balancing supply and demand. The HOEP is paid directly by consumers who participate in the wholesale electricity market, and indirectly by consumers who pay the OEB's RPP.

Commentary and Market Considerations:

The average HOEP in the Current Reporting Period was $20.75/MWh; nearly $5.00/MWh lower than in the Previous Reporting Period and almost $3.00/MWh greater than in the Summer 2014 Period.[12] Relative to the Previous Reporting Period, the lower average HOEP is to be expected given the lower demand in the Current Reporting Period (70.24 TWh vs 74.34 TWh in the Previous Reporting Period). This outcome can largely be attributed to higher demand associated with the extreme cold weather experienced in the Previous Reporting Period.

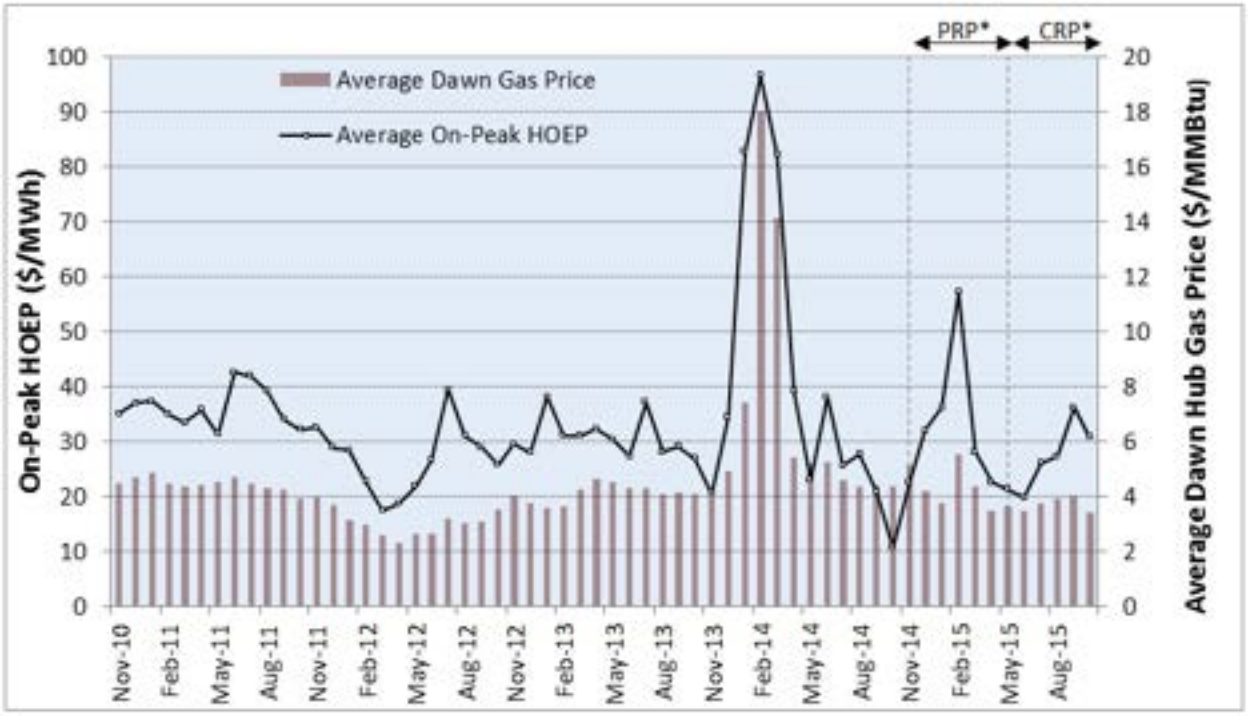
Relative to the Summer 2014 Period, demand in the Current Reporting Period was only slightly higher (< 1 TWh) but a difference in the available supply mix between the two Periods contributed to a notable difference in monthly average outcomes relative to the Summer 2014 Period. Planned outages of number of Ontario's nuclear generators removed a significant portion of baseload supply from the supply mix in the Current Reporting Period. September and October were the two lowest-priced months of the Summer 2014 Period, but represented the two highest-priced months in the Current Reporting Period.

Figure 1-4: Average Monthly Dawn Hub Day-Ahead Natural Gas Price and Average Monthly On-peak HOEP November 2010 – October 2015 ($/MWh & $/MMBtu)

Description:

Figure 1-4 plots the monthly average Dawn Hub day-ahead natural gas price and the average monthly HOEP during on-peak hours, for the previous five years.

[12] For more information regarding the monthly average HOEP in the Summer 2014 Period, see pages 12 – 14 of the Panel's October 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2014-Oct2014_20151008.pdf



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

The Dawn Hub is the most active natural gas trading hub in Ontario, and has the largest gas storage facility in the province. Gas-fired facilities can typically purchase gas day-ahead in order to ensure sufficient time to arrange for transportation; for that reason, the Dawn Hub day-ahead gas price is a relevant measure of the cost of natural gas in Ontario. Natural gas prices are compared to the HOEP during on-peak hours, as gas-fired facilities frequently set the price during these hours.

Commentary and Market Considerations:

In the four years prior to the Current Reporting Period, movements in the average Dawn Hub gas price and the average on-peak HOEP have been highly correlated; the correlation coefficient between the two variables was 0.71. The average day-ahead gas price decreased in the Current Reporting Period to $3.72/MMBtu relative to the Previous Reporting Period ($4.46/MMBtu). The HOEP experienced a similar decline in the Current Reporting Period (see Figure 1-3). The higher average on-peak HOEP in the Previous Reporting Period is attributable to higher electricity demand due to extreme cold temperatures and, in turn, greater demand for gas.

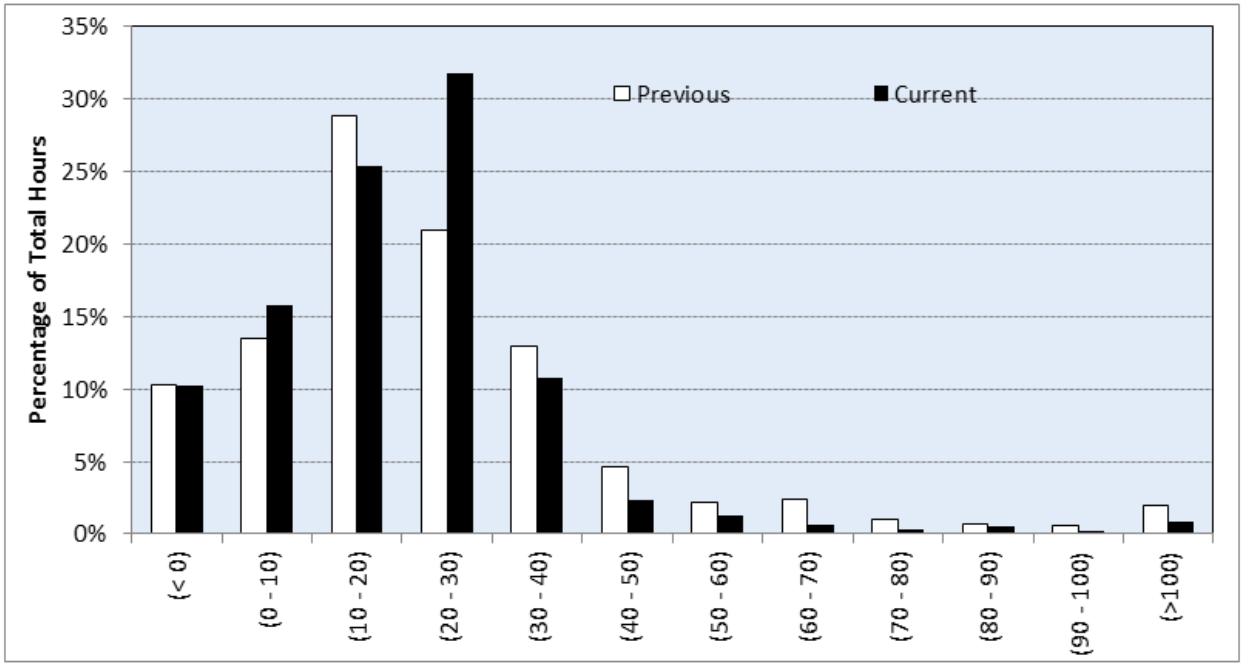
The correlation coefficient between the HOEP and the day-ahead gas price in the Current Reporting Period was 0.20. The two variables were weakly correlated in the Current Reporting Period, relative to the trend of the four years prior, despite gas-fired generators setting the real-time MCP in over 40% of all intervals (see Figure 1-6 below). This may be most attributable to the lack of volatility in the average Dawn Hub gas price relative to the average on-peak HOEP during the Current Reporting Period.[13] The average Dawn Hub gas price exhibited far less volatility than did the average on-peak HOEP, resulting in a weak correlation between the two variables.

Figure 1-5: Frequency Distribution of HOEP
November 2014 – April 2015 & May 2015 – October 2015
(% of hours, $/MWh)

Description:

Figure 1-5 compares the frequency distribution of the HOEP as a percentage of total hours for the Current Reporting Period and the Previous Reporting Period. The HOEP is grouped in $10/MWh increments (for example, the $30/MWh group includes all HOEPs between $20/MWh and $30/MWh), save for all negative HOEPs which are grouped together with all $0/MWh values in the category <=$0/MWh.

[13] The coefficients of variation for the average Dawn Hub gas price and average on-peak HOEP in the Current Reporting Period were 0.16 and 0.50, respectively. In the Previous Reporting Period the coefficients of variation were 0.51 and 0.86, respectively, and in the four years prior to the Current Reporting period they were 0.71 and 0.74, respectively. These results are consistent with the correlation coefficients of the respective time periods; the two variables are more strongly correlated when they exhibit similar levels of variation and are more weakly correlated when one of the variables exhibits greater variation than the other.



*Current means the Current Reporting Period and Previous means the Previous Reporting Period.

Relevance:

The frequency distribution of the HOEP illustrates the proportion of hours that the HOEP falls into a given price range, and provides information regarding the frequency of extremely high or low prices.

Commentary and Market Considerations:

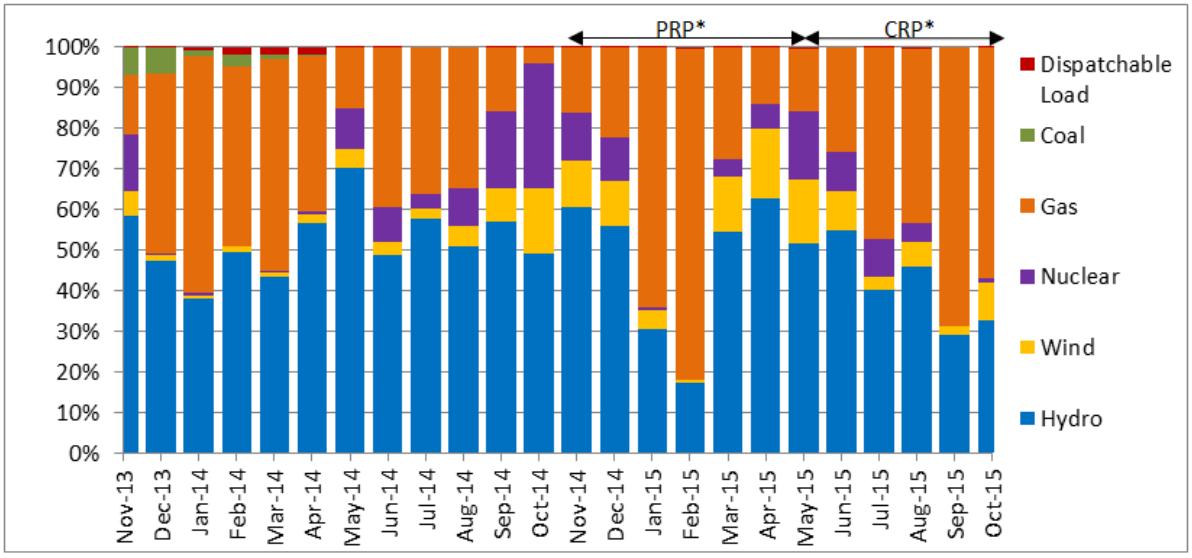
The distribution of the HOEP in the Current Reporting Period was broader than in the Summer 2014 Period, but narrower than in the Previous Reporting Period. The standard deviation of the HOEP in each period is as follows: $20.89/MWh (Summer 2014 Period), $42.14/MWh (Previous Reporting Period), and $31.35/MWh (Current Reporting Period). These standard deviations indicate that the HOEP was more volatile in the Current Reporting Period than in the Summer 2014 Period, but less so than in the Previous Reporting Period. The decrease in volatility relative to the Previous Reporting Period can largely be attributed to the wide range of weather Ontario experienced in the Previous Reporting Period; in particular, Southern Ontario experienced stretches of unseasonably mild temperatures as well as periods of extreme cold temperatures in the Previous Reporting Period.

The increase in the volatility of the HOEP relative to the Summer 2014 Period is in large part attributable to the reduction in baseload supply in the last two months of the Current Reporting Period. The reduction in nuclear supply due to planned outages decreased the number of hours of negative HOEPs in the Current Reporting Period relative to the Summer 2014 Period, and put upward pressure on the HOEP in the later months of the Current Reporting Period.[14]

Figure 1-6: Share of Resource Type setting Real-Time Market Clearing Price
November 2013 - October 2015
(% of intervals)

Description:

Figure 1-6 presents the monthly share of intervals in which each resource type set the real-time MCP, for the previous two years.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

The relative frequency of each resource type setting the real-time MCP is useful in understanding trends in the real-time MCP.

[14] For more information regarding the frequency distribution of the HOEP in the Summer 2014 Period, see page 16 of the Panel's October 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2014-Oct2014_20151008.pdf

Commentary and Market Considerations:

The previously mentioned long-term nuclear outages affected the frequency with which each fuel type set the MCP in the Current Reporting Period. Nuclear, wind and hydroelectric resources are most likely to set the MCP during the shoulder seasons when demand is low and Ontario often experiences surplus baseload generation (SBG) conditions.[15] However, in the Current Reporting Period, gas-fired resources set the MCP most often in September and October as gas-fired units were more frequently needed to compensate for the reduction in Ontario's baseload supply.

During September and October of the Summer 2014 Period, gas-fired units set the MCP in 9.7% of all intervals.[16] In September and October of the Current Reporting Period, gas-fired units set the MCP in 62.6% of all intervals. For the entire Current Reporting Period, gas-fired units set the MCP in 42.6% of all intervals, hydroelectric resources set the MCP in 42.2% of all intervals, and nuclear units set the MCP in 6.9% of all intervals. In the remaining intervals, bio-fuel or dispatchable wind and solar resources were setting the MCP.

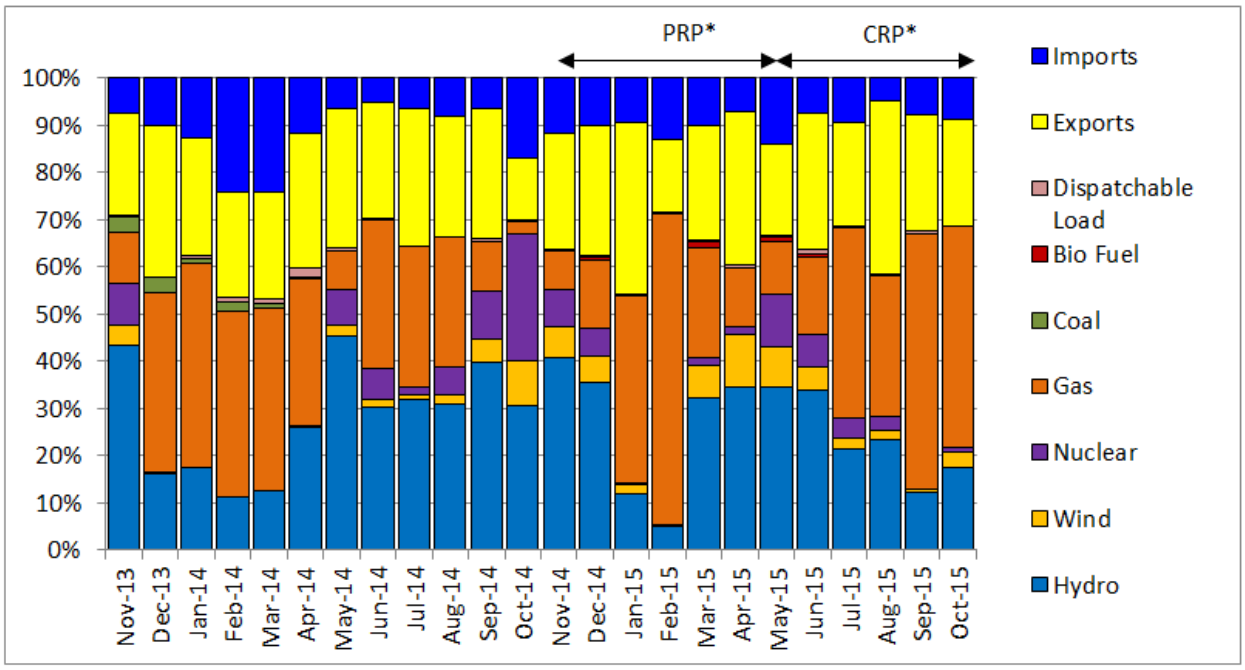
Figure 1-7: Share of Resource Type setting the One-Hour Ahead Pre-Dispatch Market Clearing Price
November 2013 - October 2015
(% of hours)

Description:

Figure 1-7 presents the monthly share of hours in which each resource type set the hour-ahead pre-dispatch (PD-1) MCP, for the previous two years.

[15] SBG conditions arise when baseload generation (comprised of combined heat and power, embedded generation, non-utility generators, nuclear, must-run hydroelectric, solar, wind, and commissioning units) is greater than Ontario demand and forecasted exports. For a description of facilities that are classified as baseload, see: http://www.ieso.ca/imoweb/pubs/consult/se91/se91-20120808-SBG_Explanation_FPFG.pdf.

[16] For more information on resources setting the real-time MCP in the Summer 2014 Period see pages 16 – 18 of the Panel's October 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2014-Oct2014_20151008.pdf



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

When compared with Figure 1-6 (resources setting the real-time MCP), the relative frequency of each resource type setting the PD-1 MCP provides insight into how the marginal resource mix changes from pre-dispatch to real-time. Of particular importance is the frequency with which imports and exports set the PD-1 MCP, as these transactions are unable to set the real-time MCP.[17] When the price is set by an import or export in pre-dispatch, a divergence between the pre-dispatch and the real-time MCP is more likely to occur.

Commentary and Market Considerations:

Similar to the situation described in the Commentary section associated with Figure 1-6, the reduction in baseload supply in September and October of the Current Reporting Period led to an increase in high-priced resources setting the PD-1 MCP in those months. The most notable result, relative to the Summer 2014 Period, is the frequency with which gas-fired generators set

[17] Due to scheduling protocols, imports and exports are scheduled hour-ahead. Therefore, in real-time imports and exports are fixed for any given hour and their prices are adjusted in real-time to -$2,000 and $2,000/MWh, respectively. This means that they are scheduled to flow for the entire hour regardless of the price, though their schedule may change within an hour to maintain reliability. As a result, they are treated like non-dispatchable resources in real-time.

the PD-1 MCP; in September and October of 2014, gas-fired units set the PD-1 MCP in 96 hours[18], while in the Current Reporting Period that number increased to 728 hours.

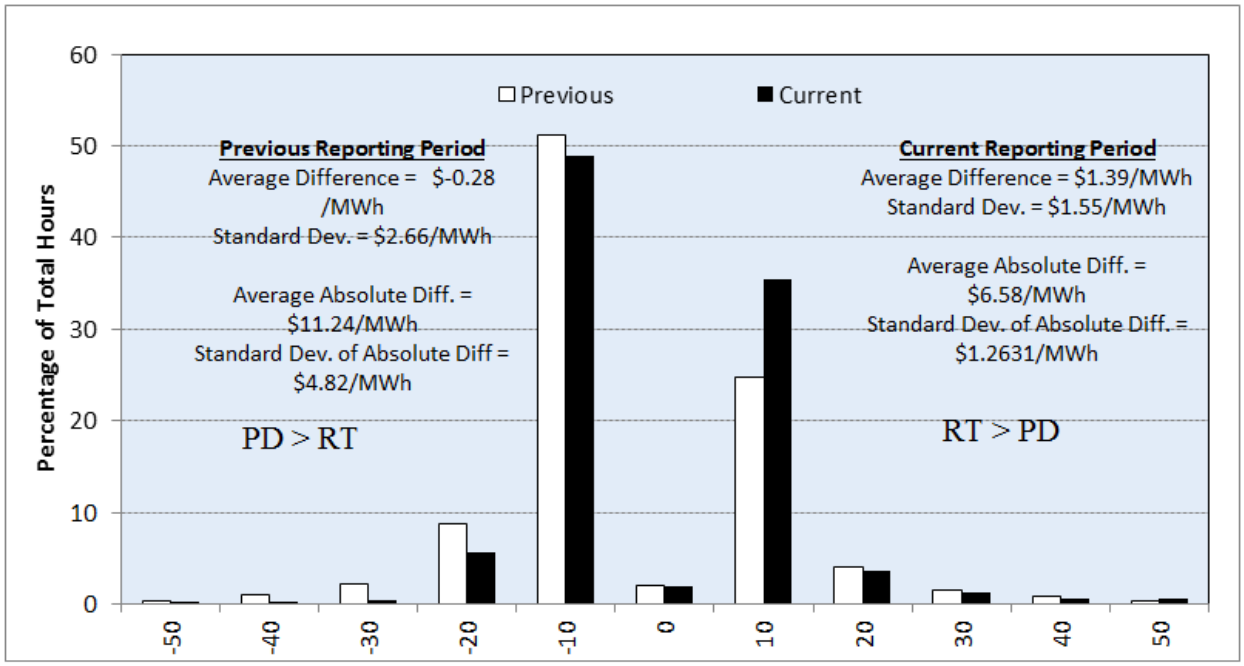
Figure 1-8: Difference between the HOEP and the One-Hour Ahead Pre-Dispatch Price November 2014 – April 2015 & May 2015 – October 2015 (% of hours)

Description:

Figure 1-8 presents the frequency distribution of differences between the HOEP and the PD-1 MCP for the Current and Previous Reporting Periods. The price differences are grouped in $10/MWh increments, save for the $0/MWh category which represents no change between the PD-1 MCP and the HOEP. The number of instances where the absolute difference between the PD-1 MCP and the HOEP exceeded $50/MWh is negligible and so is not included in Figure 1-8, and the same is true of Figure 1-9 in relation to the absolute difference between the three-hour ahead MCP and the HOEP.

Positive differences on the x-axis represent a price increase from pre-dispatch to real-time, while negative differences represent a price decrease from pre-dispatch to real-time.

[18] For more information on resources setting the one-hour ahead MCP in the Summer 2014 Period see pages 18 – 19 of the Panel's October 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2014-Oct2014_20151008.pdf



Relevance:

The PD-1 MCP determines the schedules for import and export transactions for real-time delivery. While intertie transactions are scheduled on the basis of the PD-1 MCP, they are settled on the basis of the HOEP. To the degree that supply and demand conditions change from PD-1 to real-time, imports or exports may be over- or under-scheduled relative to the HOEP. For instance, an exporter that is willing to pay the PD-1 MCP may not want to pay the HOEP if it is higher (due to, for example, a generator outage that occurs between PD-1 and real-time). In such a case, if the exporter was to pay the HOEP they could lose money on the transaction. Conversely, if prices fall, the exporter could see a higher profit but the volume of exports could be sub-optimal.

Commentary and Market Considerations:

Relative to the Previous Reporting Period, differences between the HOEP and the PD-1 MCP were narrower in the Current Reporting Period as the HOEP was within +/- $20/MWh of the PD-1 MCP in 95.4% of all hours, compared to 89.4% in the Previous Reporting Period. This decrease in price volatility between the PD-1 MCP and the HOEP is confirmed by the Current Reporting Period's lower standard deviation ($1.55/MWh) relative to the Previous Reporting Period ($2.66/MWh). The distribution of differences between the HOEP and the PD-1 MCP in

the Current Reporting Period was comparable to that in the Summer 2014 Period[19], and the average absolute difference for the two periods was also similar ($6.58/MWh in the Current Reporting Period and $6.02/MWh in the Summer 2014 Period).

Table 1-2: Factors Contributing to Differences between One-Hour Ahead Pre-Dispatch Prices and Real-Time Prices May 2014 – October 2014, November 2014– April 2015 & May 2015 – October 2015 (MWh & % of Ontario Demand)

Description:

Real-time prices diverge from PD-1 prices as a result of changing conditions from pre-dispatch to real-time. The Panel has identified the following as the six main factors that contribute to the difference between the PD-1 MCP and the HOEP:

Supply

- Self-scheduling and intermittent generation forecast deviation (other than wind);
- Wind generation forecast deviation;
- Generator outages; and
- Import failures/curtailments.

Demand

- Pre-dispatch to real-time demand forecast deviation; and
- Export failures/ curtailments.

Metrics for all but one of these factors are presented in Table 1-2 as the average absolute difference between PD-1 and real-time. The effect of generator outages is not shown in this table as they tend to be infrequent, although short-notice outages can have significant price effects.

[19] For more information regarding the difference between the HOEP and the PD-1 MCP in the Summer 2014 Period, see pages 19 – 21 of the Panel's October 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2014-Oct2014_20151008.pdf

Factor	Current		Previous		Summer 2014	
	Average Absolute Difference (MW per hour)	Average Absolute Difference (% of Ontario Demand)	Average Absolute Difference (MW)	Average Absolute Difference (% of Ontario Demand)	Average Absolute Difference (MW)	Average Absolute Difference (% of Ontario Demand)
Ontario Average Demand	15,205		16,461		15,118	
Pre-dispatch to Real-time Demand Forecast Deviation	211	1.39	213	1.29	213	1.41
Self-Scheduling and Intermittent Forecast Deviation (Excluding Wind)	81	0.53	55	0.33	51	0.33
Wind Deviation	112	0.74	126	0.77	97	0.64
Net Export Failures/Curtailments	82	0.54	101	0.61	76	0.50

Relevance:

Identifying the factors that lead to deviations between the PD-1 MCP and the HOEP provides insight into the root causes of price risks that participants, particularly importers and exporters, face as they enter offers and bids into the market.

Commentary & Market Considerations:

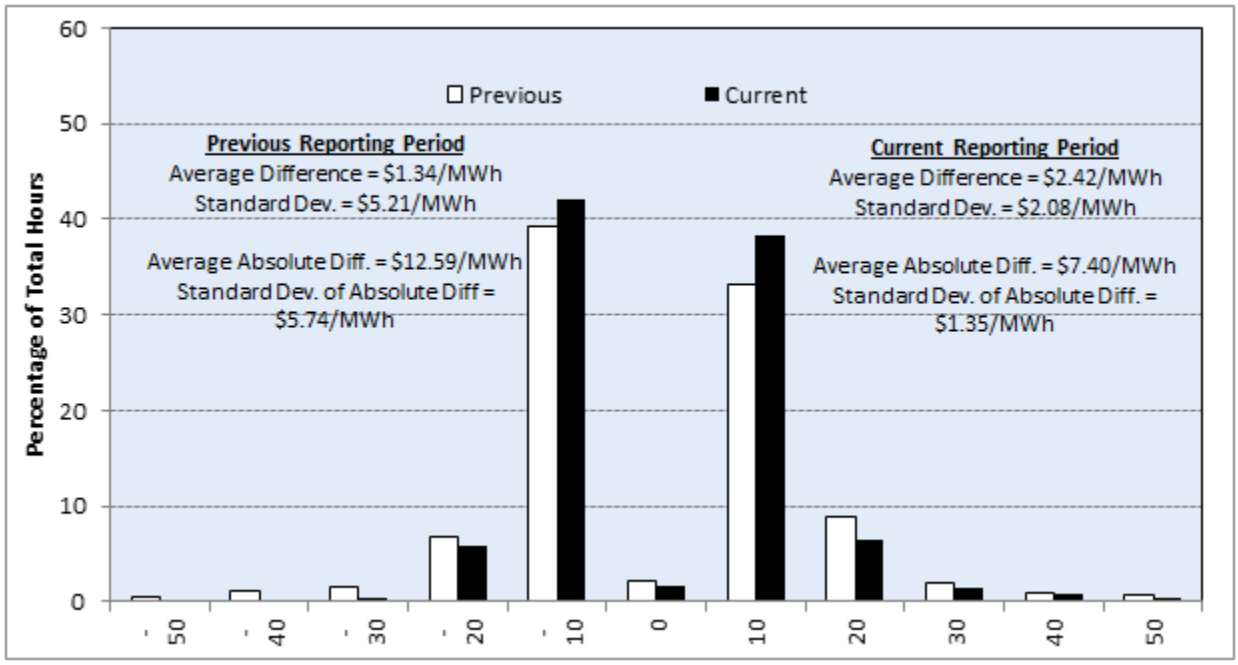
The average absolute difference in demand forecast deviation has remained relatively constant throughout the last three reporting periods. In the Previous Reporting Period, demand forecast deviation represented a smaller portion of Ontario demand due to the higher average demand totals. The average absolute difference of wind deviation as a percentage of Ontario demand in the Current Reporting Period has increased relative to the Summer 2014 Period[20], and is likely to continue increasing as additional wind capacity continues to be added to Ontario's generation fleet.

[20] For more information regarding wind deviation in the Summer 2014 Period, see page 22 of the Panel's October 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2014-Oct2014_20151008.pdf

Figure 1-9: Difference between the HOEP and the Three-Hour Ahead Pre-Dispatch Price
November 2014 – April 2015 & May 2015 – October 2015
(% of hours)

Description:

Figure 1-9 presents the frequency distribution of differences between the HOEP and the three-hour ahead pre-dispatch (PD-3) MCP for the Current and Previous Reporting Periods. The price differences are grouped in $10/MWh increments, save for the $0/MWh category which represents no change between the PD-3 MCP and the HOEP. Positive differences on the x-axis represent a price increase from pre-dispatch to real-time, while negative differences represent a price decrease from pre-dispatch to real-time.



Relevance:

The PD-3 MCP is the last price signal seen by the market prior to the closing of the offer and bid window, after which offers and bids may only be changed with the approval of the IESO.

Differences between the HOEP and the PD-3 MCP indicate changes in the supply and demand conditions from PD-3 to real-time. The resultant changes in price are informative for non–quick

start facilities and energy limited resources,[21] both of which rely on pre-dispatch prices to make operational decisions. Price changes are also important to intertie traders, whose bids and offers are often informed by pre-dispatch prices in Ontario.

Commentary and Market Considerations:

Similar to the results shown in Figure 1-8, the Current Reporting Period demonstrated a greater concentration of price differences within +/- $20/MWh relative to the Previous Reporting Period. As evidenced by the lower standard deviation of price differences in the Current Reporting Period, less volatility existed between PD-3 and real-time than in the Previous Reporting Period.

As should be expected, differences between the PD-3 MCP and the HOEP were broader than differences between the PD-1 MCP and the HOEP in the Current Reporting Period; in approximately 82% of all hours the PD-3 MCP was within +/- $10/MWh of the HOEP, while the PD-1 MCP was within the same range of the HOEP in approximately 86% of all hours. The PD-1 MCP and the PD-3 MCP both most commonly over-forecasted the real-time price. The most frequent occurrence in the Current Reporting Period was for the HOEP to clear between $0.01/MWh and $10/MWh less than the pre-dispatch forecasted MCP; this occurred in 49% of hours with respect to the PD-1 MCP and in 42% of hours with respect to the PD-3 MCP.

Figure 1-10: Monthly Global Adjustment by Component
November 2013 – October 2015
($)

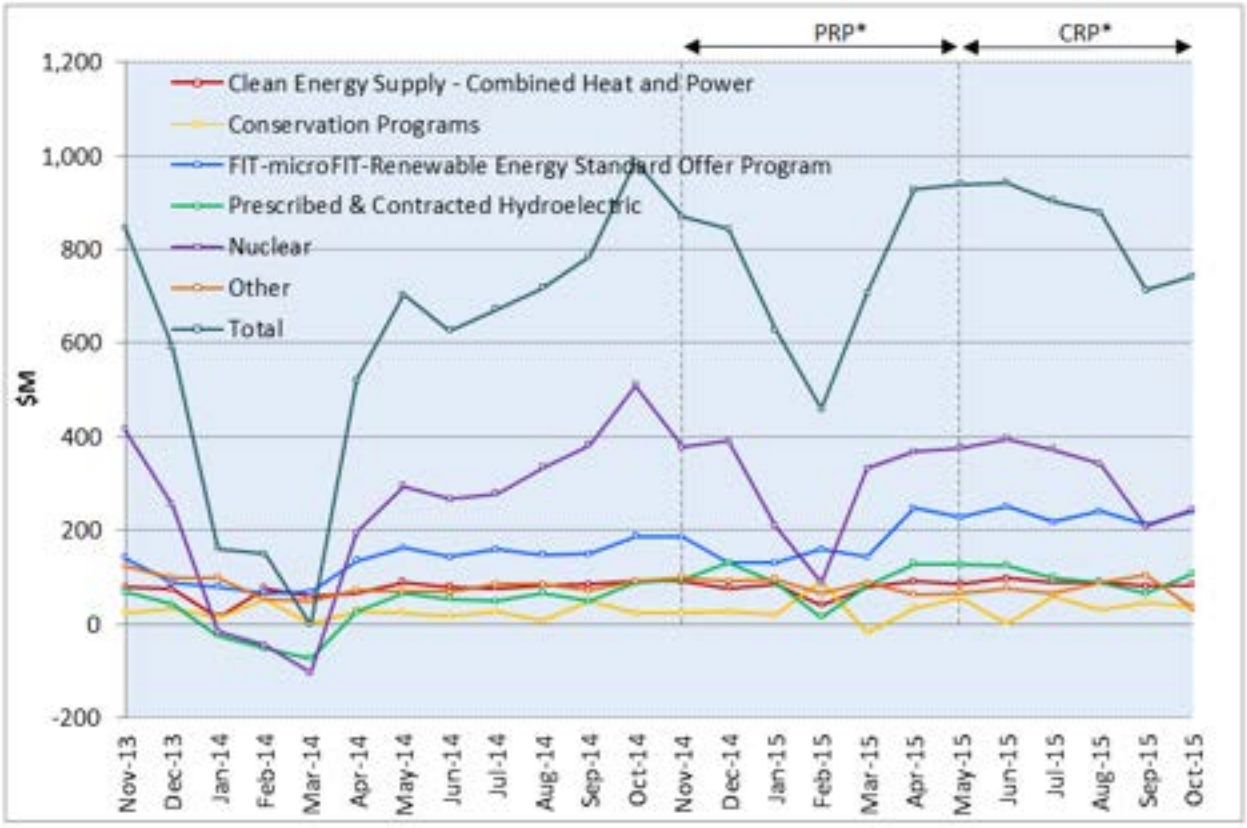
Description:

Figure 1-10 plots the revenue recovered through the GA each month, by component, for the previous two years. For this purpose, the total GA is divided into the six following components:

- Payments to nuclear facilities (Bruce Nuclear Generating Station and Ontario Power Generation's (OPG's) nuclear assets);
- Payments to holders of Clean Energy Supply (CES) contracts and Combined Heat and Power (CHP) contracts;
- Payments to prescribed or contracted hydroelectric generation;

[21] Energy limited resources constitute a subset of generation facilities that experience fuel restrictions such that they cannot operate at capacity for the entire day; instead, they must optimize their production across the highest-priced hours. For example, some hydroelectric facilities regularly experience fuel restrictions due to limited water availability.

- Payments to holders of contracts for renewable power (Feed-in Tariff (FIT), microFIT and the Renewable Energy Standard Offer Program (RESOP));
- Payments related to the IESO's conservation programs; and
- Payments to others (including under the IESO's demand response programs, to holders of non-utility generator contracts and under the contract with OPG's Lennox Generating Station)



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

Showing the GA by component identifies the extent to which each component contributes to the total GA. The high GA totals for a particular component may be the result of increases in contracted rates, increased production, increased capacity, or decreases in the HOEP.

Commentary and Market Considerations:

Four of the five highest monthly GA totals since market opening occurred at the end of the Previous Reporting Period and the beginning of the Current Reporting Period (April through July), with June representing the second highest monthly GA total on record. FIT, micro-FIT and

RESOP contributions to the GA continued to rise, as they surpassed $200 million/month for the first time in April of 2015 and remained above that monthly level throughout the Current Reporting Period. As total renewable capacity in Ontario continues to grow, its proportional contribution to the GA is expected to continue increasing.

As noted in the Commentary associated with for Table 1-1, relative to the Summer 2014 Period increases in payments to hydroelectric and renewable generators and increases in conservation program payments were the primary factors leading to the higher GA in the Current Reporting Period. Relative to the Summer 2014 Period, these payments increased by the following amounts: $243 million for hydroelectric generation; $440 million for FIT, micro-FIT and RESOP generation; and $86 million for conservation programs. This is the first reporting period in which total payments to holders of contracts under the FIT, micro-FIT and RESOP programs exceeded $1 billion ($1.4 billion), which is a product of the aforementioned increase in renewable power capacity in Ontario.[22]

The decline in the GA at the end of the Current Reporting Period corresponds with the decrease in available nuclear supply due to the planned outages noted earlier. This decline in the GA also corresponds with an increase in the HOEP in September and October, which is consistent with the inverse relationship that typically exists between the HOEP and the GA. The HOEP was higher in those months and a greater portion of the compensation payable to generators was recovered through the market. In the Current Reporting Period, September saw the lowest total GA payments to most contracted or regulated generators and the highest monthly average HOEP.

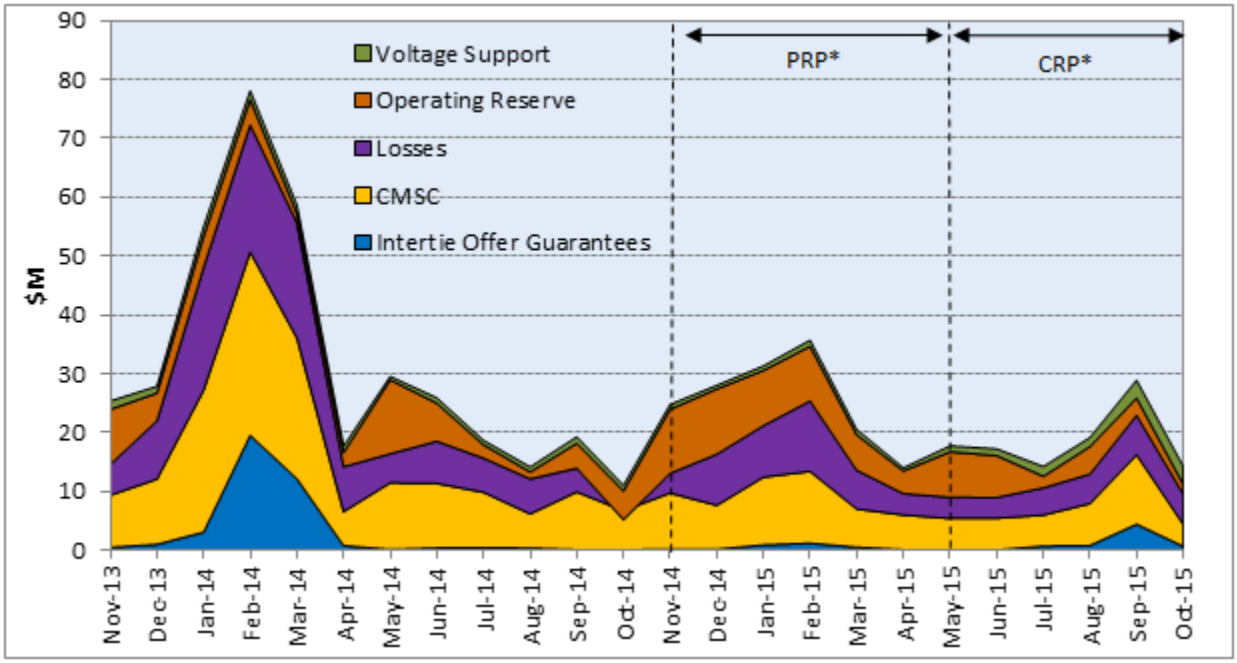
Figure 1-11: Total Hourly Uplift By Component and Month
November 2013 – October 2015
($)

Description:

Figure 1-11 presents the total hourly uplift charges (Hourly Uplift) by component and month, for the previous two years. Hourly Uplift components include Congestion Management Settlement

[22] For more information regarding the monthly GA by component in the Summer 2014 Period, see page 25 of the Panel's October 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2014-Oct2014_20151008.pdf

Credit (CMSC) payments, day-ahead and real-time Intertie Offer Guarantee (IOG) payments, Operating Reserve (OR) payments, voltage support payments, and losses.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

Hourly Uplift is a component of the effective price in Ontario. It is charged to wholesale consumers (including distributors) based on their share of total hourly demand in order to recover the costs associated with various market programs and design features.

Commentary and Market Considerations:

Hourly Uplift attributable to OR declined throughout the Current Reporting Period, as was the case in the Summer 2014 Period, and was significantly lower than in the Previous Reporting Period. Demand in the Current Reporting Period was lower than in the Previous Reporting Period, which in general results in an increase in available OR supply. When less generation capacity is required to meet demand, more capacity is made available as OR supply, placing downward pressure on OR prices. Despite the decline in average OR prices, both OR prices and the HOEP have risen during times of operating reserve scarcity, a pattern which the Panel examines in greater detail in Chapter 2 of this report.

Similar to the HOEP, Hourly Uplift peaked in September during the Current Reporting Period, primarily driven by an increase in CMSC ($11.8 million) and IOG ($4.4 million) payments. In September, IOGs were the highest since the period between November 2013 – April 2014 (the Winter 2014 Period). Ontario was a net importer in 235 hours in September and repeatedly committed upwards of 1,500 MWh of imports, per hour, over evening peak periods through the Day-Ahead Commitment Process. By comparison, Ontario was a net importer in a total of 27 hours in the first four months of the Current Reporting Period and was not a net importer for any hour in September of the Summer 2014 Period.[23]

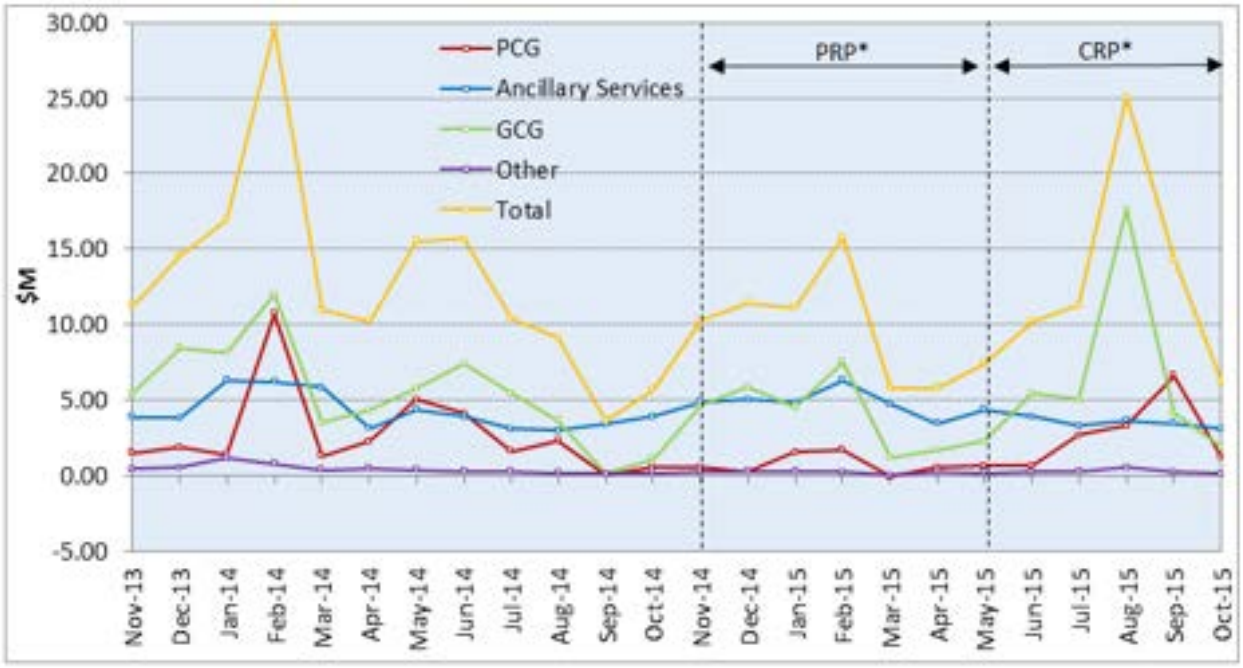
Figure 1-12: Total Monthly Uplift by Component and Month
November 2013 – October 2015
($)[24]

Description:

Figure 1-12 plots the total monthly uplift charges (Monthly Uplift) by component and month, for the previous two years. Monthly Uplift has the following components:[25]

- Payments for ancillary services (i.e., regulation service, black start capability, monthly voltage support);
- Guarantee payments to generators —payments under the Day-Ahead Production Cost Guarantee (DA-PCG) and Real-Time Generation Cost Guarantee (RT-GCG) programs; and
- Other, which includes charges and rebates such as compensation for administrative pricing and the local market power rebate, among others.

[23] Net import figures noted in this paragraph are based on unconstrained schedules.
[24] The Panel has changed the manner in which it allocates Monthly Uplift charges to more closely align reported costs with the month in which they were incurred rather than the month in which they were settled. This primarily impacts the monthly reported totals for payments under the Real-time Generation Cost Guarantee program. For example, in Figure 1-12 all costs submissions for that program for starts occurring between August 11 and September 9, 2015 were settled at the end of September. However, the bulk of the settlements pertain to starts that occurred in August 2015. The Panel now reports these costs to have occurred in August 2015 rather than September 2015. As a result of this change, monthly totals reported in this report will not be directly comparable to those previously reported by the Panel.
[25] The Monthly Uplifts in this figure are all uplifts that are charged other than on an hourly basis.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

Monthly Uplift is a component of the effective price in Ontario. It is charged to wholesale consumers (including distributors) based on their share of total daily or monthly demand, as applicable, in order to recover the costs associated with various market programs and design features.

Commentary and Market Considerations:

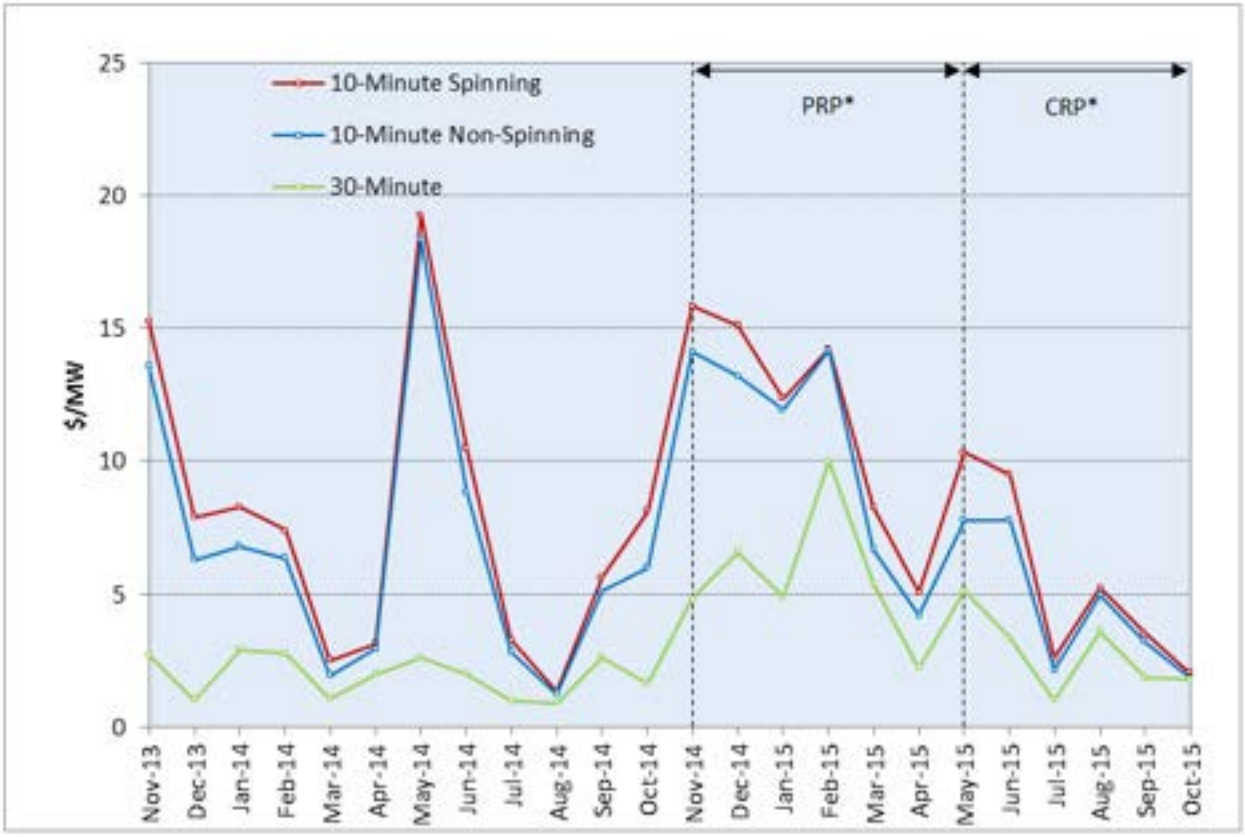
Monthly Uplift charges rose gradually through the first three months of the Current Reporting Period as demand increased with rising temperatures from spring to summer, and then more than doubled from July to August. The Monthly Uplift total of $25.1 million in August was the highest since the Winter 2014 Period and was primarily driven by increases in RT-GCG payments ($17.6 million).

This outcome is attributable to three cost submissions that occurred at the beginning of September. One submission associated with a single RT-GCG start represented 50% of all cost submissions for the settlement period. Two other individual submissions each represented 9.5% of total cost submissions. Chapter 2 provides additional information regarding RT-GCG submissions in the Current Reporting Period.

Figure 1-13: Average Monthly Operating Reserve Prices by Category November 2013 – October 2015 ($/MW)

Description:

Figure 1-13 plots the monthly average OR price for the previous two years for the three OR markets: 10-minute spinning (10S), 10-minute non-spinning (10N), and 30 minute (30R).



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

The three OR markets are co-optimized with the energy market, meaning that resources are scheduled to minimize the combined costs of energy and OR. As such, prices in these markets tend to be subject to similar dynamics.

Resources offer supply into the OR markets just as they offer supply into the energy market; however, OR demand is set unilaterally by the IESO's total OR requirement. The total OR requirement, as specified in the reliability standards adopted by the North American Electric Reliability Corporation and the Northeast Power Coordinating Council, is sufficient megawatts

to allow the grid to recover from the single largest contingency (such as the largest generator tripping offline) within 10 minutes, plus additional OR to recover from half of the second largest contingency within 30 minutes. These requirements ensure that the IESO- controlled grid can operate reliably.

Commentary and Market Considerations:

Average OR prices in the Current Reporting Period were less than half those in the Previous Reporting Period for each class of reserve. Average OR prices for the Current Reporting Period were $5.53/MW, $4.62/MW and $2.79/MW for 10S, 10N and 30R respectively, compared to $11.81/MW, $10.71/MW and $5.65/MW in the Previous Reporting Period. This outcome can be attributed in part to lower demand in the Current Reporting Period, increasing available supply in the OR markets in the vast majority of hours. Despite the decline in average prices, OR prices reached high levels in a few hours when the IESO ran short of OR in order to cover shortfalls in the energy market. This topic is covered in greater detail in Chapter 2.

Average OR prices were slightly lower in the Current Reporting Period relative to the Summer 2014 Period in both of the 10-minute reserve markets, and slightly higher in the 30-minute market. Similar to the Summer 2014 Period, 10-minute prices were highest in May. As reported in Chapter 2, nine of the fifteen anomalous OR payments in the Current Reporting Period occurred during the month of May.

In May of the Summer 2014 Period, voltage reduction was scheduled for a total of 40.4 GWh of OR, while hydroelectric generators were scheduled for a total of 455.4 GWh (representing hydroelectric's lowest monthly total for that period). In May of the Current Reporting Period, voltage reduction was scheduled for a total of 6.6 GWh while hydroelectric generators were scheduled for a total of 662 GWh (hydroelectric's highest monthly total of the Current Reporting Period), indicating less reliance on voltage reductions for OR relative to the same time in the previous year. Despite the increase in available OR supply from hydroelectric resources relative to the Summer 2014 period, the price for each class of OR peaked in May. This topic is also discussed in more detail in Chapter 2.

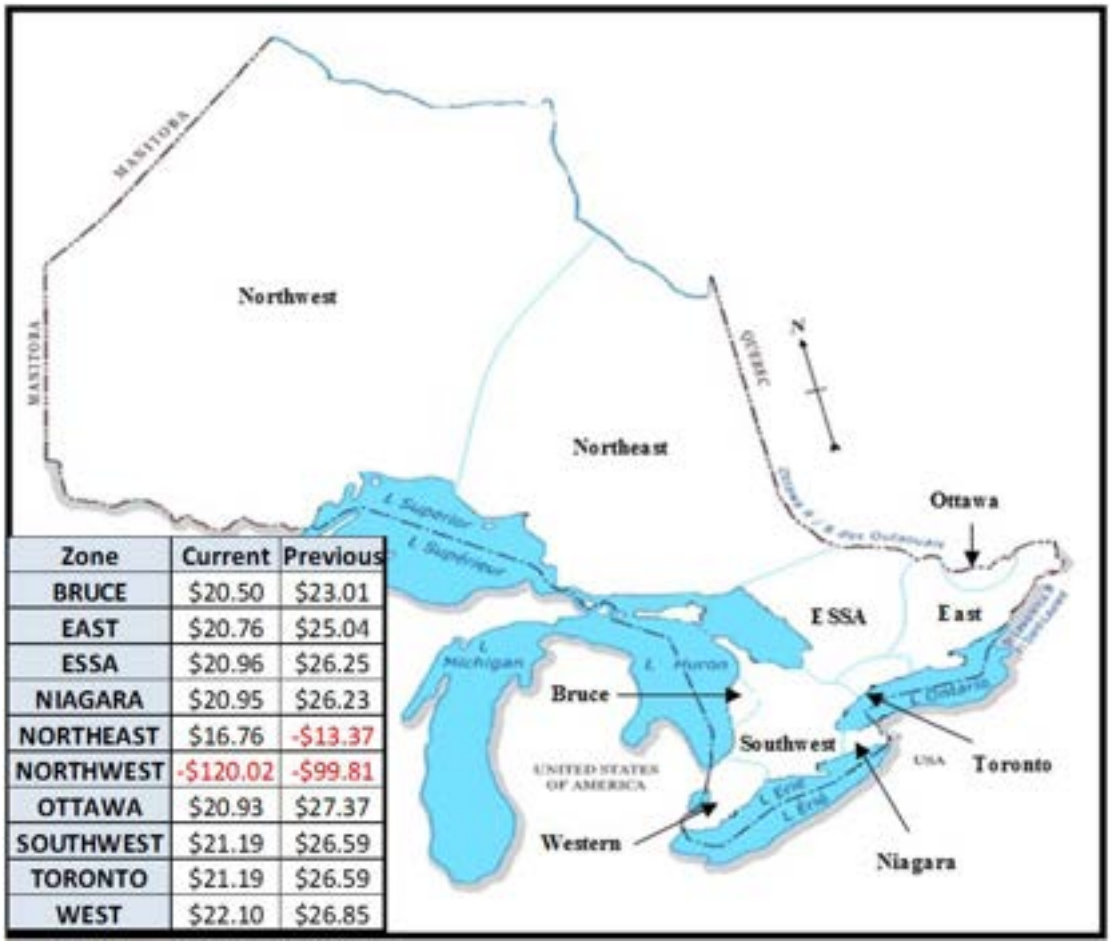
Contrary to the Summer 2014 Period, OR prices did not increase at the end of the Current Reporting Period. Gas-fired generation was online during the fall shoulder season more

frequently than in years past (see Figure 1-6 and associated commentary), increasing the available OR supply and, in turn, placing downward pressure on average OR prices.[26]

Figure 1-14: Average Internal Nodal Prices by Zone
November 2014– April 2015 & May 2015 – October 2015
($/MWh)

Description:

Figure 1-14 illustrates the average nodal price of Ontario's ten internal zones for the Current and Previous Reporting Periods. In principle, nodal prices represent the cost of supplying the next megawatt of power at a given location.



Zone	Current	Previous
BRUCE	$20.50	$23.01
EAST	$20.76	$25.04
ESSA	$20.96	$26.25
NIAGARA	$20.95	$26.23
NORTHEAST	$16.76	-$13.37
NORTHWEST	-$120.02	-$99.81
OTTAWA	$20.93	$27.37
SOUTHWEST	$21.19	$26.59
TORONTO	$21.19	$26.59
WEST	$22.10	$26.85

[26] For more information regarding OR prices in the Summer 2014 Period, see pages 28 – 30 of the Panel's October 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2014-Oct2014_20151008.pdf

Relevance:

While the HOEP is the uniform wholesale market price across Ontario, the cost of satisfying demand for electricity may differ across the province due to limits on the transmission system and the cost of generation in different regions. Nodal prices approximate the marginal value of electricity in each region and reflect Ontario's internal transmission constraints. Differences in average nodal prices identify zones that are separated by system constraints. In zones in which average nodal prices are high, the supply conditions are relatively tight; in zones in which average nodal prices are low, the supply conditions are relatively more abundant.

In general, nodal prices outside the northern parts of the province move together. Most of the time the nodal prices in the Northwest and Northeast zones are significantly lower than the nodal prices in the rest of the province due primarily to two factors: first, in these zones, there is surplus low-cost generation (in excess of demand); and second, there is insufficient transmission to transfer this low-cost surplus power to the southern parts of the province.

Contributing to negative prices in the northern zones are hydroelectric facilities operating under must-run conditions. Must-run conditions necessitate that units generate at certain levels of output for safety, environmental, or regulatory reasons. Under such conditions, market participants offer the must-run energy at negative prices in order to ensure that the units are economically selected and scheduled.

Commentary and Market Considerations:

Other than in the Northeast zone, nodal prices predictably decreased in the Current Reporting Period as a result of lower demand relative to the Previous Reporting Period. Except for the Northeast and Northwest zones, nodal prices across the province tend to closely resemble each other and trend in the same direction, as was again the case in the Current Reporting Period.

The Northeast and Northwest zones often exhibit markedly different nodal price outcomes than the rest of the province for the reasons noted in the Relevance section above. The Northwest zone is a good example of this situation in the Current Reporting Period as its average nodal price trended in the same direction as the rest of the province, but was approximately $125/MWh and $140/MWh lower in the Previous and Current Reporting Periods, respectively.

In the Current Reporting Period, and unlike the rest of the province, the nodal price in the Northeast zone increased relative to the Previous Reporting Period. One factor contributing to this outcome was a reduction in available supply due to increased levels of generator outages during the Current Reporting Period. The total installed generation capacity of dispatchable resources in the Northeast zone is approximately 3,460 MW. During the Current Reporting Period, an average of 701 MW of capacity per month was unavailable due to outages, compared to an average of 591 MW per month in the Previous Reporting Period. September and October had the two highest monthly totals of unavailable supply in the Northeast as a result of generator outages, which corresponded with the two highest monthly average nodal prices in the zone.

Figures 1-15 & 1-16: Congestion by Interface Group

Description:

Figures 1-15 and 1-16 report the number of hours per month of import and export congestion, respectively, by interface for the previous two years.

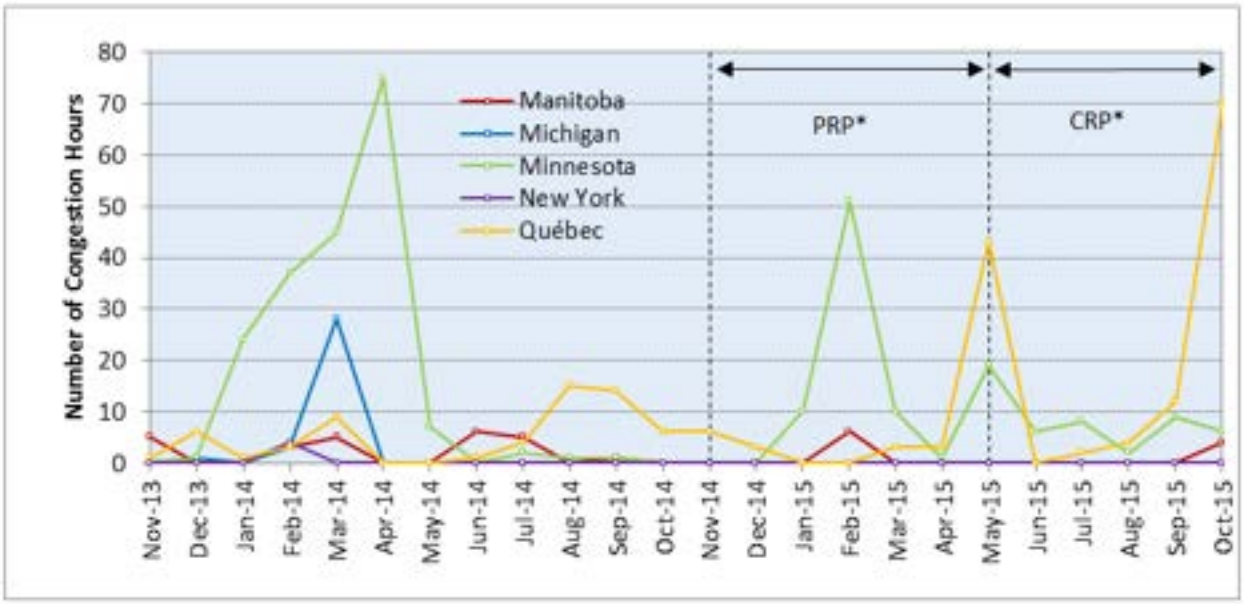
Relevance:

The interties that connect Ontario to neighbouring jurisdictions have finite transfer capabilities. The supply of intertie transfer capability is dictated by the available capacity at each interface, and also by line outages and de-ratings. When an intertie has a greater amount of economic net import offers (or economic net export bids) than its one-hour ahead pre-dispatch transfer capability, the intertie will be import (or export) congested. Demand for intertie transfer capability is driven in part by price differences between Ontario and other jurisdictions.

The price for import and export transactions can differ from the MCP, as it is based on the intertie zonal price where the transaction is taking place. For a given intertie, importers are paid the intertie zonal price, while exporters pay the intertie zonal price. When there is import congestion, importers receive less for the energy they supply while exporters pay less for the energy they purchase—the intertie zonal price is lower than the MCP. When there is export congestion, importers receive more for the energy they supply while exporters pay more for the energy they purchase—the intertie zonal price is greater than the MCP. The difference between the intertie zonal price and the MCP is called the Intertie Congestion Price (ICP). The ICP for a given hour is calculated in PD-1 depending on whether or not the PD-1 energy schedule has

more energy transactions than available intertie transmission line capacity. The ICP is positive when there is export congestion and negative when there is import congestion. This is discussed in more detail in the Relevance section associated with Figure 1-17.

Figure 1-15: Import Congestion by Interface Group
November 2013 – October 2015
(number of hours in the unconstrained schedule)



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Commentary and Market Consideration:

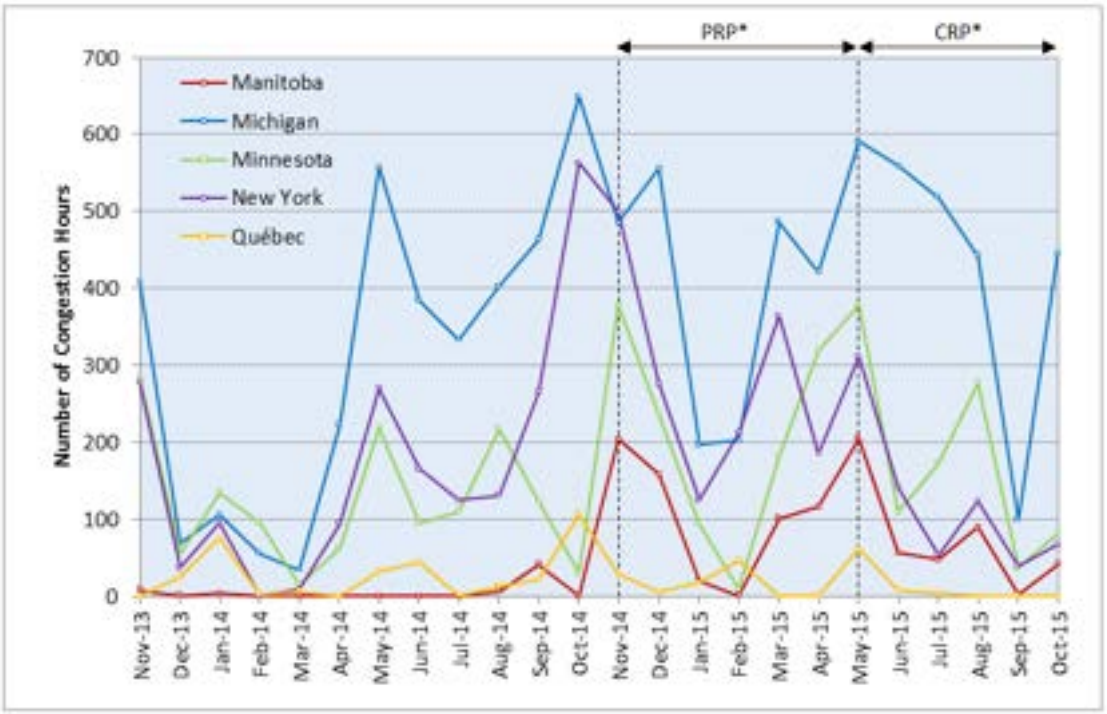
Québec[27] was the only interface to experience more than twenty hours of import congestion in any month in the Current Reporting Period, and did so in May and October. The number of import congested hours in those two months alone (113 hours) exceeded the total congested hours at the Québec interface in all months of the Previous Reporting Period and Summer 2014 Period combined (55 hours).[28]

[27] Figures reported in Chapter 1 for Québec pertain exclusively to the Outaouais intertie, which is the largest commercial intertie, by capacity, between Ontario and Québec.
[28] For more information on import congestion in the Summer 2014 Period, see pages 33 – 34 of the Panel's October 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2014-Oct2014_20151008.pdf

Capacity on the Québec interface was restricted to half of its normal limit for much of May due to an extended outage, which led to an increase in congested hours without any material change in the level of import activity at that interface.

In October, Québec experienced more import congested hours than any other interface over the past three reporting periods. The increased frequency of import congestion in October was primarily driven by an increase in import activity. Both the total quantity of import offers and the average hourly quantity to be scheduled in the unconstrained sequence peaked in October. From May to August, the hourly average import quantity in the unconstrained sequence was less than 520 MW; in October the hourly average was 972 MW. With a large portion of Ontario's baseload supply unavailable due to outages, increased import activity was one means by which Ontario demand was met by alternative sources of supply.

Figure 1-16: Export Congestion by Interface Group
November 2013 – October 2015
(number of hours in the unconstrained schedule)



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Commentary and Market Consideration:

Increased export congestion at the Manitoba interface is a trend that began occurring with increased regularity in September 2014[29] and that persisted through the Previous Reporting Period and the Current Reporting Period, relative to November 2013 through August 2014. Of the three most recent reporting periods, Manitoba experienced its highest number of congested hours in the Current Reporting Period.

Across all interfaces, export congestion sharply declined in September except at Québec which experienced only four export congested hours between July and October of the Current Reporting Period. The frequency of congested hours increased again in October at all interfaces except Québec, but remained below levels experienced in the earlier months of the Current Reporting Period. Historically, export congestion tends to increase as Ontario enters the fall shoulder season, but this trend was not observed in September and October of the Current Reporting Period; the three major interfaces by capacity - New York, Michigan and Québec – all experienced higher levels of export congestion during the same months of the Summer 2014 Period.

While the HOEP increased throughout the Current Reporting Period and peaked in September, it remained lower than prices in external jurisdictions to which Ontario power is typically exported. Comparing to prices in the three main external destinations for Ontario power (Midcontinent Independent System Operator at Michigan, New York Independent System Operator and PJM Interconnection LLC), the HOEP was still at least CAD$7/MWh less expensive than in any of these other jurisdictions in September (see Table 1-3 below).[30] Lower export congestion in September and October of the Current Reporting Period corresponded with a decrease in the price difference between Ontario and those neighbouring jurisdictions in those two months.

[29] For more information regarding export congestion in the Summer 2014 Period, see pages 34 – 35 of the Panel's October 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2014-Oct2014_20151008.pdf

[30] For five days in September, export capacity at the New York interface was reduced by approximately 40%, but there were no other significant transmission limitations.

Table 1-3: Monthly Average Hourly Electricity Prices – Ontario and Neighbouring Jurisdictions May 2015 – October 2015 ($/MWh)

Description:

Table 1-3 lists the average hourly real-time spot prices for electricity, by month, in Ontario and neighbouring jurisdictions that are the most active in terms of intertie trading.

The Ontario price reported is the HOEP. Absent congestion at an interface, importers receive, and exporters pay, the HOEP when transacting in Ontario. The external prices reported are the real-time Locational Marginal Prices (LMPs) that correspond with the node on the other side of Ontario's interface with each jurisdiction.

Month	Ontario	Manitoba[31]	Michigan (MISO)[32]	Minnesota (MISO)[33]	New York (NYISO)[34]	PJM (PJM Interconnection LLC)[35]
May	14.22	20.93	34.45	25.36	26.48	35.24
June	14.20	24.67	33.54	26.91	19.61	31.39
July	20.25	29.30	36.20	32.52	27.03	36.61
August	21.87	29.11	35.74	31.71	30.00	34.29
September	29.86	28.26	36.92	31.09	37.78	38.18
October	24.11	20.44	33.47	24.67	27.53	31.56

Relevance:

One objective of intertie trading is to take advantage of arbitrage opportunities. Intertie traders attempt to purchase (export) low-priced power from one jurisdiction and sell (import) that power to another jurisdiction at a higher price to capture the price differential.[36]

[31] The Panel assumed that the real-time LMPs at the 'MHEB' node published by MISO are representative of the external prices at the Manitoba interface.
[32] The Panel assumed that the real-time LMPs at the 'ONT_DECO_PSOUT' node published by MISO are representative of the external prices at the Michigan interface.
[33] The Panel assumed that the real-time LMPs at the 'ONT_W' node published by MISO are representative of the external prices at the Minnesota interface.
[34] The Panel assumed that the real-time LMPs at the 'OH' node published by NYISO are representative of the external prices at the New York interface.
[35] The Panel assumed that the real-time LMPs at the 'IMO' node published by PJM are representative of the external prices in PJM that exporters can capture by wheeling through New York or Michigan.
[36] Differences exist in terms of the specific costs that are reflected in the spot price of electricity between jurisdictions. For example, in Ontario the HOEP is not reflective of a gas-fired generation unit's start-up costs, as these costs are settled through uplift. The specific components that comprise the spot price will vary from jurisdiction to jurisdiction, but they are still the most accurate and readily available indicators of economic decision-making in real-time for intertie traders.

Price differences between jurisdictions can change from one hour to the next due to changes in any of the numerous factors which determine demand (e.g. weather) and supply (e.g. outages). Changes in the price differential will affect the direction of trade between those jurisdictions. Energy trade may not always flow from jurisdictions with low prices to jurisdictions with high prices; imperfect information, timing issues and rapidly changing conditions, among other factors, can lead to intertie trades that appeared efficient ex-ante but appear inefficient or unprofitable ex-post. However, average prices over longer time horizons should be informative about trends in the direction of trade between jurisdictions. Over the course of a month, if the average electricity price in Ontario is lower than in another jurisdiction, trade should flow from Ontario to that jurisdiction in that month on a net basis.

As discussed in the Relevance section associated with Figures 1-15 and 1-16, importers and exporters in Ontario do not receive or pay the HOEP if congestion exists at an interface in a given hour. Congestion can erode or even reverse the original arbitrage opportunity between the HOEP and the external jurisdiction. Nevertheless, the HOEP and the spot price in the external jurisdiction are two key pieces of information in determining whether to import or export from Ontario.

Commentary and Market Considerations:

As discussed above in the Commentary associated with Figure 1-16 and in the Commentary associated with Table 1-5 and Figures 1-25 and 1-26, Ontario experienced a significant reduction in net exports and a corresponding decrease in export congestion beginning in September of the Current Reporting Period relative to earlier months. Typically, as Ontario enters the fall shoulder season, domestic demand declines and prices decrease, which often leads to an increase in export activity, as was the case in the Summer 2014 Period.[37]

The monthly average HOEPs in September and October were the highest of the Current Reporting Period. While those monthly average HOEPs were lower than in most neighbouring

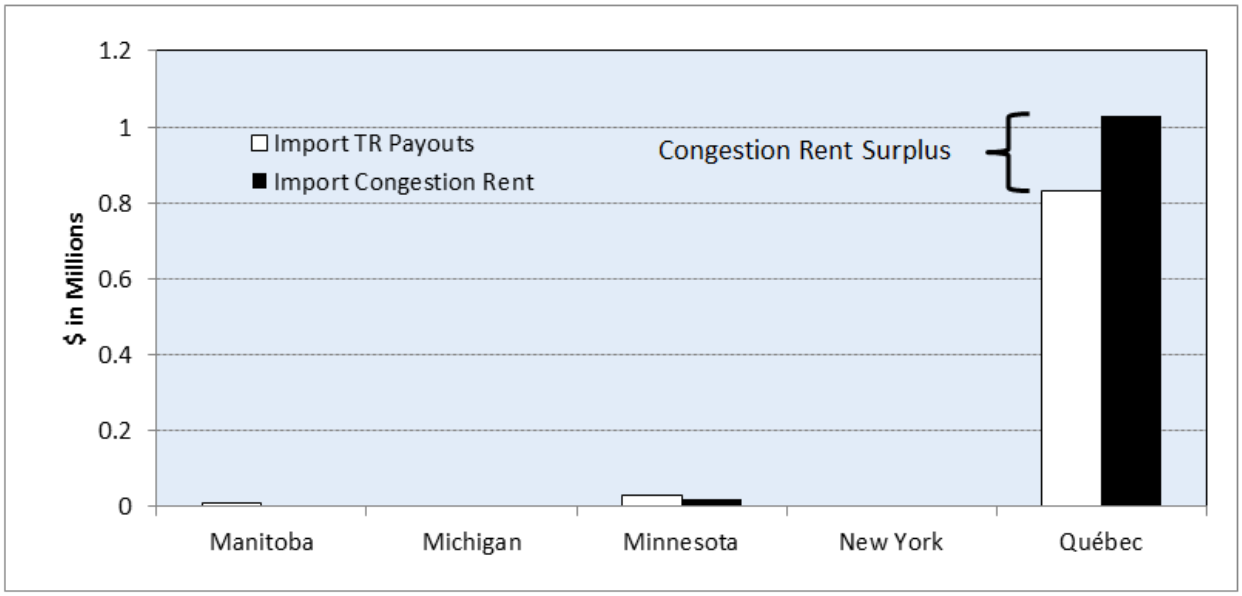
[37] For more information regarding demand and export activity in the Summer 2014 Period, see pages 34-35, 44-46 and 50-51 of the Panel's October 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2014-Oct2014_20151008.pdf

jurisdictions[38] - suggesting the existence of arbitrage opportunities - net exports declined. This outcome can be attributed to a decline in the price differential between Ontario and its neighbouring jurisdictions in the same months, relative to months earlier in the Current Reporting Period; as the price differentials narrowed, arbitrage opportunities became less attractive, contributing to an overall decline in net exports and export congestion.

Figure 1-17: Import Congestion Rent & Transmission Rights Payouts by Interface Group
May 2015 – October 2015
($)

Description:

Figure 1-17 compares the total collection of import congestion rent to total payouts under transmission rights (TRs) by interface group for the Current Reporting Period.



Relevance:

As discussed in the Relevance section associated with Figures 1-15 and 1-16, an intertie zonal price is less than the Ontario price when an intertie is import congested; the difference in prices is the ICP and is equal to the difference (if any) between the PD-1 Ontario price and the PD-1

[38] The average HOEP in September and October was greater than the external price at the Manitoba interface but lower than the external prices in all other neighbouring jurisdictions.

intertie zonal price. While the importer is paid the lesser intertie zonal price, the buyer in the wholesale market still pays the HOEP. The difference between the amount collected from the purchaser and the amount paid to the importer is known as import congestion rent. Congestion rent accrues to the IESO's Transmission Rights clearing account (TR clearing account). This account is discussed in greater detail in the Relevance section associated with Figure 1-19.

To enable intertie traders to hedge against the risk of price fluctuations due to congestion, the IESO administers TR auctions. TRs are sold on the basis of intertie and direction (import or export) for periods of one month or one year. The owner of a TR is entitled to a payment (or payout) equal to the ICP multiplied by the amount of TRs they hold every time congestion occurs on the intertie in the direction for which they own a TR. TRs therefore allow an intertie trader to hedge against congestion-related price fluctuations by ensuring that intertie traders are settled on the HOEP and not the intertie zonal price. An intertie trader that holds the exact same amount of import TRs as the amount of energy they are importing is perfectly hedged against congestion, as TR payouts will exactly offset price differences between the Ontario price and the price in the intertie zone. Payouts to TR holders are disbursed from the TR Clearing Account.

While TR payouts should theoretically be offset by congestion rent collected, in practice this is often not the case. One of the main reasons for this is the difference between the number of TRs held by market participants and the number of net imports/exports flowing during hours of congestion. When TR payouts exceed congestion rent collected, the TR Clearing Account is drawn down; the opposite is true when congestion rent collected exceeds TR payouts.

In addition to congestion rent collected and TR payouts, there is a third input to the TR Clearing Account—TR auction revenues. TR auction revenues are the proceeds from selling TRs (a payment into the TR Clearing Account). Due to Ontario's two-schedule price system,[39] transaction failures and intertie de-ratings, there are congestion events in which a congestion rent shortfall arises; instead of remaining revenue neutral, these events draw down the TR Clearing

[39] Intertie congestion (and thus the ICP and TR payouts) is calculated based on the pre-dispatch unconstrained schedule, while congestion rent collected is based on the real-time constrained schedule. To the degree that the pre-dispatch unconstrained schedule differs from the real-time constrained schedule, TR payouts may differ from congestion rent collected. In the extreme, congestion may occur in one direction (*e.g.*, import) in the pre-dispatch unconstrained schedule, but the real-time constrained schedule has net transactions in the opposite direction (*e.g.*, export). In this case, import TR payouts are made and negative import congestion rents are "collected".

Account. These shortfalls are covered primarily by TR auction revenues. The Panel has previously expressed the view that TR auction revenues should be for the benefit of consumers in the form of a reduction in transmission charges.[40] In that context, every dollar of congestion rent shortfall represents a dollar that does not accrue to the benefit of Ontario customers. In recent years, the IESO has taken to making more frequent disbursements from the TR Clearing Account.

Note that interties with a high frequency of import congestion hours (see Figure 1-15) do not necessarily correlate with high import TR payouts and import congestion rent, primarily because of the differences in intertie capacity (and thus TRs sold) at each intertie.

Commentary and Market Consideration:

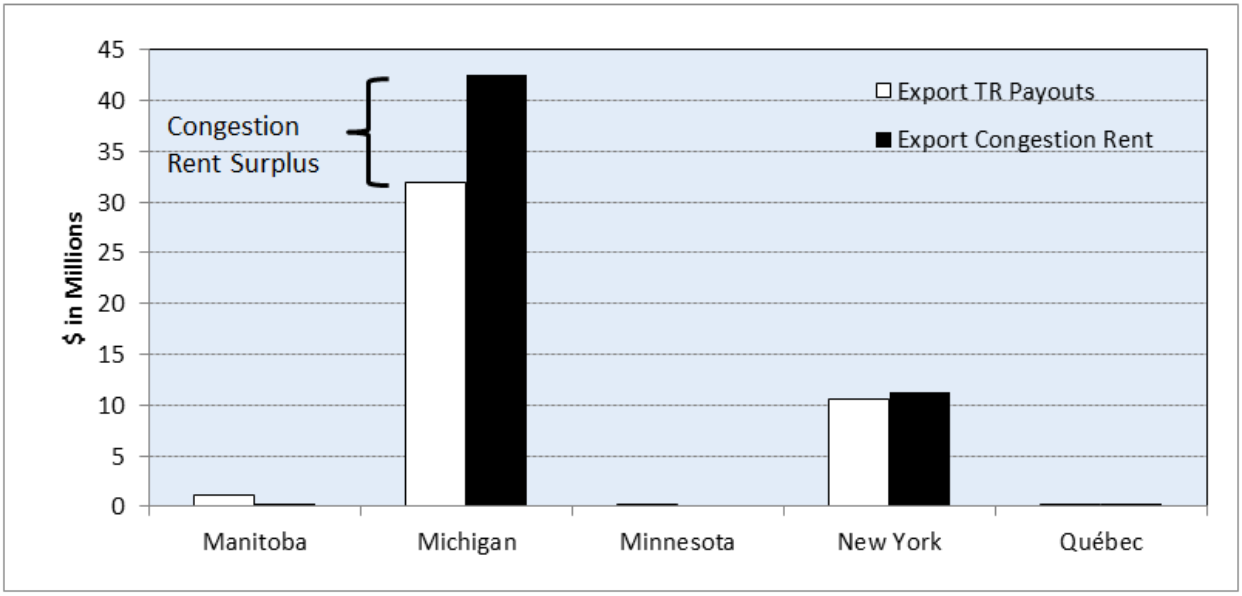
An excess of $198,000 in import congestion rents, relative to TR payouts, was collected in relation to the Québec interface in the Current Reporting Period. This outcome was the product of the increase in import activity at the Québec interface in the last two months of the Period, primarily in October (see the Commentary associated with Figure 1-15). The quantity of TRs sold for the Québec intertie was constant throughout the Current Reporting Period at 615 MW – half of the Québec interface's full capacity - while the level of import activity increased significantly at the end of the Current Reporting Period. Owning short-term TRs in October for the Québec interface was a profitable position as the relatively high rate of import congestion was coupled with the second lowest cost for a short-term TR in the Current and Previous Reporting Periods, at $5/MW (see Table 1-5 below); a single MW of an import TR for the Québec interface yielded a return on investment of 15,090% in October.

[40] If there were no TRs in Ontario, but all other aspects of the market design were retained, congestion rent would still be collected by the IESO whenever there was congestion on an intertie. Those congestion rents are the price importers and exporters are prepared to pay for scarce transmission capacity, suggesting that rents might be paid to transmission owners. But as the transmission companies are rate-regulated entities, any congestion rents paid to them would presumably be used to offset their regulated revenue requirement. Thus, their customers (Ontario consumers) would benefit from congestion rents. For more information on the TR market and the basis for disbursing funds from the TR Clearing Account to offset transmission service charges, see pages 146-160 of the Panel's January 2013 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2011-Apr2012_20130114.pdf

Figure 1-18: Export Congestion Rent & Transmission Rights Payouts by Interface Group
May 2015 – October 2015
($)

Description:

Figure 1-18 compares the total collection of export congestion rent to total TR payouts by interface group for the Current Reporting Period.



Relevance:

When there is export congestion, an intertie zonal price is more than the Ontario price. See the Relevance section associated with Figure 1-17, which describes the relationship between congestion rents and TR payments in regards to import congestion. The relationship between congestion rents and TR payments for export congestion is the converse of that for import congestion. In general, if there are less congestion rents collected, there is a congestion rent shortfall (and the TR clearing account balance decreases); if there are more congestion rents collected than TR payments, there is a congestion rent surplus (and the TR Clearing Account balance increases).

Commentary and Market Consideration:

Across all interfaces, export congestion rents collected were in excess of TR payouts by just over $10 million, with the primary contributor being the Michigan interface which was the most

heavily export congested interface in the Current Reporting Period (see Figure 1-16). The average export capacity of the Michigan interface exceeded average export TR ownership over the Current Reporting Period by 387 MW. This means that, on average, in hours where congestion existed, congestion rent was being collected on a greater quantity of MWs than those receiving TR payouts, resulting in a net surplus of export congestion rent over the Current Reporting Period.

Only the Manitoba interface experienced a shortfall in congestion rents in excess of $100,000 during the Current Reporting Period ($900,000). Manitoba experienced the highest rate of export failures in the Current Reporting Period (see Table 1-6), which contributed to the under-collection of congestion rents. If a scheduled export transaction fails in an hour where congestion existed, congestion rent goes uncollected as no energy is purchased, though the transaction contributed to congestion at the interface in pre-dispatch.

Table 1-4: Average Long-Term (12-month) Transmission Right Auction Prices by Interface and Direction November 2014 – October 2015 ($/MW)

Description:

Table 1-4 lists the average auction prices of 1 MW of long-term (year-long) TRs sold for each interface, in either direction, since November 2014 (these TRs would have been valid during the Current Reporting Period).

			Average Auction Price ($/MW)				
Direction	Auction Date	Period TRs are Valid	Manitoba	Michigan	Minnesota	New York	Québec
Import	Nov-14	Jan-15 to Dec-15	3,788	-	-	2,480	-
	Feb-15	Apr-15 to Mar-16	2,847	1,172	4,525	767	1,367
	May-15	Jul-15 to May-16	3,294	511	5,306	456	2,454
	Aug-15	Oct-15 to Aug-16	2,844	505	4,445	404	1,106
Export	Nov-14	Jan-15 to Dec-15	5,695	-	33,518	61,225	-
	Feb-15	Apr-15 to Mar-16	7,293	43,370	28,558	36,741	4,176
	May-15	Jul-15 to May-16	15,883	62,961	26,374	42,910	6,745
	Aug-15	Oct-15 to Aug-16	12,605	72,534	21,850	51,193	9,865

Relevance:

If an auction is efficient, the price paid for one megawatt of TRs should reflect the expected payout from owning that TR for the period. This is equivalent to the expected sum of all ICPs in the direction of the TR over the period for which the TR is valid. The greater the expected frequency and/or magnitude of congestion on the intertie, the more valuable the TR. Assuming an efficient auction, auction revenues signal the market's expectation of intertie congestion conditions for the forward period.

Commentary and Market Consideration:

With certain exceptions, long-term export TR prices increased in each successive auction, an indication that the expectation of the market is that export congestion on the interties would persist through the summer of 2016. Auction prices for Manitoba, Michigan and New York increased significantly relative to auctions held the previous year: in November of 2013, export TRs for Manitoba were sold at $2,521/MW, while the lowest price for auctions held from November 2014 to August 2015 was $5,695/MW. In the auctions held from November 2014 to August 2015, the highest export TR prices for Michigan and New York reached $72,534/MW and $61,225/MW, respectively. This compares with prices of $38,836/MW and $32,216/MW in the auctions for long term export TR's in the period November 2013 to August 2014.[41]

Table 1-5: Average Short-Term (One-month) Transmission Right Auction Prices by Interface and Direction November 2014 – October 2015 ($/MW)

Description:

Table 1-5 lists the auction prices for 1 MW of short-term (month-long) TRs sold at each interface, in either direction, during the Previous and Current Reporting Periods.

[41] For more information regarding long-term TR auction prices in November 2013 - August 2014, see page 40 of the Panel's October 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2014-Oct2014_20151008.pdf

		Average Auction Price ($/MW)				
Direction	Period TRs are Valid	Manitoba	Michigan	Minnesota	New York	Québec
Import	Nov-14	506	134	251	129	118
	Dec-14	380	119	351	136	131
	Jan-15	328	136	317	160	19
	Feb-15	306	45	268	171	32
	Mar-15	259	99	376	79	152
	Apr-15	310	55	418	90	135
	May-15	317	16	-	16	90
	Jun-15	387	12	-	11	81
	Jul-15	417	30	201	7	79
	Aug-15	202	12	164	7	0
	Sep-15	135	19	290	15	118
	Oct-15	165	15	122	15	5
Export	Nov-14	329	7,626	-	5,022	2,000
	Dec-14	701	6,245	1,674	6,049	3,169
	Jan-15	692	6,176	2,001	2,500	2,070
	Feb-15	410	3,678	1,868	2,500	300
	Mar-15	511	4,221	2,074	2,689	158
	Apr-15	810	4,494	1,735	2,262	179
	May-15	1,300	5,575	-	2,520	27
	Jun-15	751	6,897	-	2,645	82
	Jul-15	459	7,462	-	930	37
	Aug-15	580	5,947	-	1,125	6
	Sep-15	393	2,701	-	671	123
	Oct-15	310	4,009	-	2,297	72

Relevance:

As discussed in the Relevance section associated with Table 1-4, auction revenues signal market participant expectations of intertie congestion conditions for the forward period.

Commentary and Market Consideration:

Short-term auction prices in the Current Reporting Period were reflective of the relative frequency of congestion experienced at each interface. TRs for the Michigan and New York interfaces were the most expensive; these and were also the most frequently congested interfaces throughout the Current Reporting Period (see Figure 1-16). Short-term auction prices were also consistent with the general trends seen for the long-term auctions (see Table 1-4).

Looking at the average of Manitoba's short-term auction prices in the Current Reporting Period, there was an increase of 625% (average cost of a TR: $632/MW) relative to the Summer 2014 Period (average cost of a TR: $101/MW)[42]; no monthly price in the Current Reporting Period was below $310/MW, while only one monthly price in the Summer 2014 Period exceeded $60/MW. The rising cost of export TRs was also reflected in the long-term auctions and speaks to the increased frequency of export congestion at the Manitoba interface discussed in the Commentary associated with Figure 1-16.

Short-term auction prices for the Michigan interface were higher the first four months of the Current Reporting Period relative to the Summer 2014 Period by an average of $2,964/MW. This outcome is likely attributable to the reduced quantity of TRs sold, as the monthly average of TRs held for the Michigan interface was 192 MW lower in the Current Reporting Period (899 MW) than it was in the Summer 2014 Period (1091 MW).

For the Michigan and New York interfaces, short-term TRs were most expensive in September and October in the Summer 2014 Period. The same did not hold true in the Current Reporting Period, as September was the least expensive month for both interfaces and October was the second least expensive for the Michigan interface. The reduction in TR auction prices for the Michigan and New York interfaces indicates that exporters anticipated less favorable export conditions in Ontario during the 2015 fall shoulder season relative to the Summer 2014 Period and prior months of the Current Reporting Period. At least in part, this expectation could have been founded on publicly available information about the reduction in Ontario's baseload supply resulting from nuclear outages in September and October.[43]

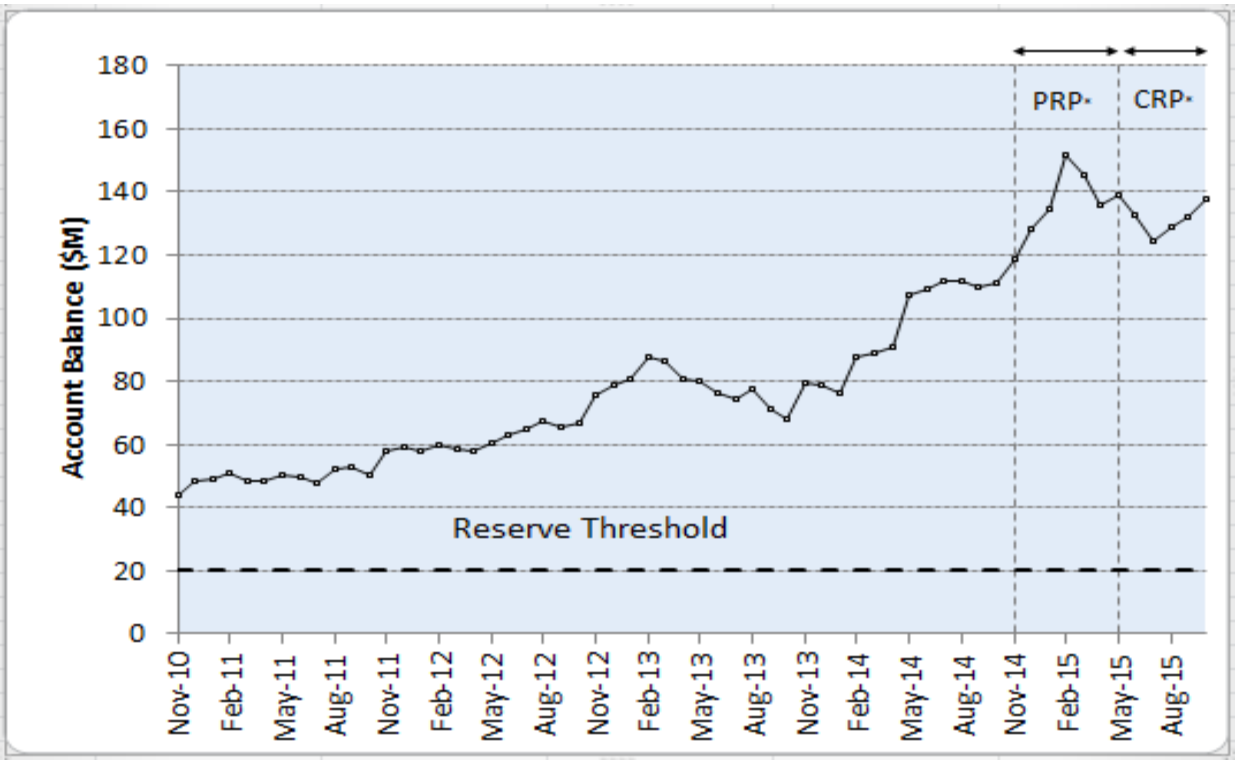
[42] For more detailed information regarding Manitoba's short term auction prices in the Summer 2014 Period see pages 41 – 42 of the Panel's October 2015 Monitoring Report, available at:
http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2014-Oct2014_20151008.pdf

[43] For more information regarding short-term TR auction prices in the Summer 2014 Period, see pages 41-42 of the Panel's October 2015 Monitoring Report, available at:
http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2014-Oct2014_20151008.pdf

Figure 1-19: Transmission Rights Clearing Account Balance
November 2010 – October 2015
($)

Description:

The TR Clearing Account is an account administered by the IESO to record various amounts relating to TRs. Figure 1-19 shows the estimated balance in this account at the end of each month for the previous five years.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

The TR Clearing Account balance is affected by five types of transactions:

Credits

- Congestion rent received from the market
- TR auction revenues
- Interest earned on the TR Clearing Account balance

Debits

- TR payouts to TR holders
- Disbursements to Ontario market participants

Tracking TR Clearing Account transactions over a period of time provides an indication of the health of the TR market and the policies that govern it. The account has a reserve threshold of $20 million set by the IESO Board of Directors; funds in excess of this threshold can be disbursed to wholesale loads and exporters at the discretion of the IESO Board of Directors.

Commentary & Market Considerations:

In the Current Reporting Period, the balance in the TR Clearing Account increased by $1.46 million; from $135.95 million at the end of the Previous Reporting Period to $137.41 million at the end of the Current Reporting Period. This change was composed of:

- $113.23 million in revenue
    - $55.48 million in congestion rent collected
    - $57.15 million in auction revenues
    - $0.60 million in interest
- $111.76 million in disbursements
    - $44.96 million in TR payments to rights holders
    - $66.80 million in disbursement to Ontario consumers

In the Current Reporting Period the TR clearing account ended approximately $117 million above the Reserve Threshold. In December 2015, the IESO announced a lump sum disbursement from the TR Clearing Account of $100 million, to occur during the November 2015 billing cycle. [44]

2 Demand

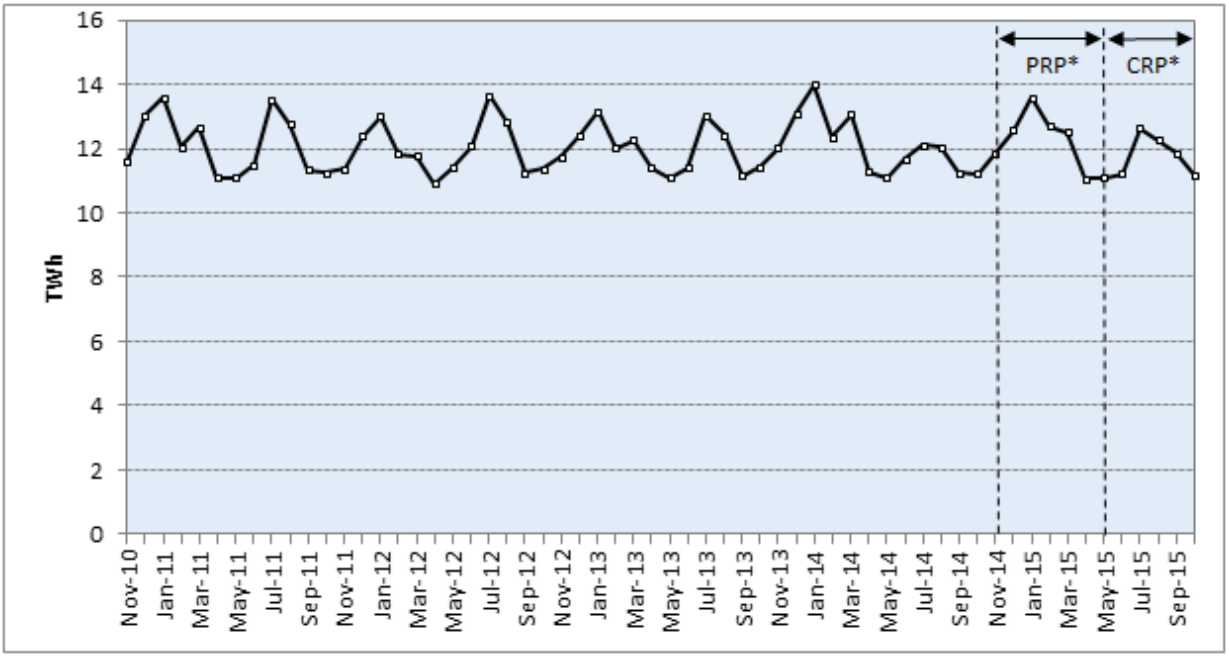
This section discusses Ontario energy demand for the Current Reporting Period relative to previous years.

[44] For details see: http://www.ieso.ca/Pages/News/NewsItem.aspx?newsID=7268

Figure 1-20: Monthly Ontario Energy Demand
November 2010 – October 2015
(TWh)

Description:

Figure 1-20 presents energy consumption by all Ontario consumers in each month in the past 5 years. The figure represents Ontario demand, which includes demand satisfied by behind-the-meter (embedded) generators.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

Ontario monthly consumption information shows seasonal variations in consumption and year-to-year changes in consumption patterns.

Commentary and Market Consideration:

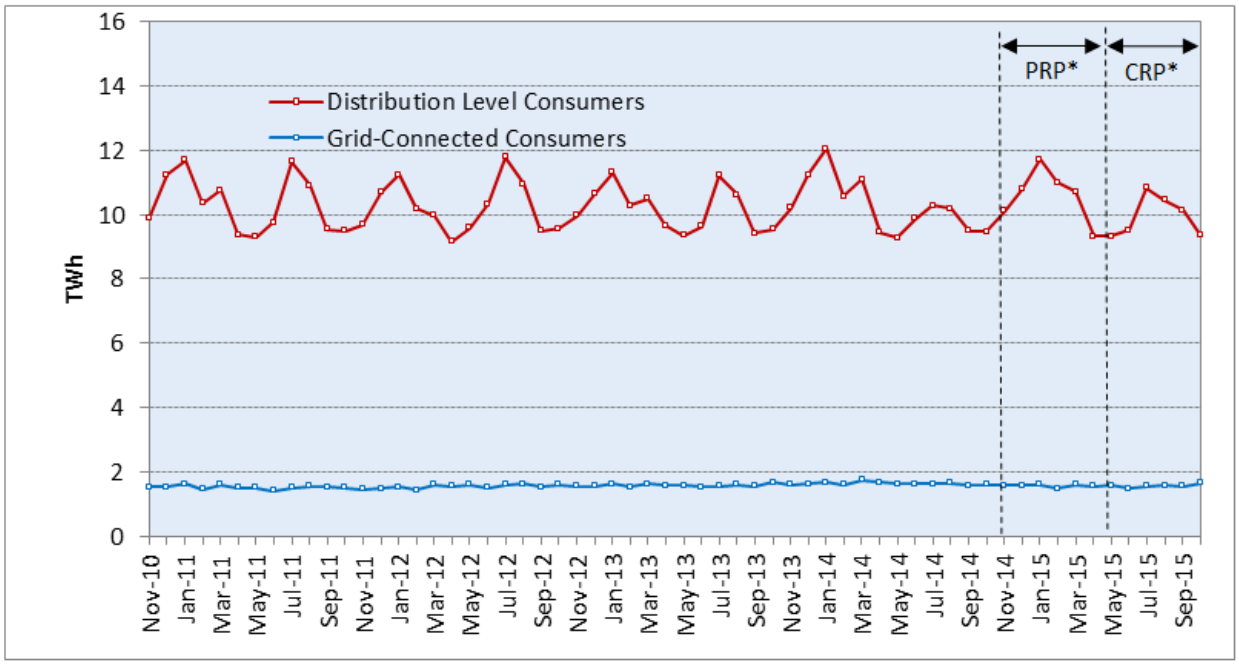
Historically, Ontario has been a summer peaking jurisdiction, but 2015 marked the third consecutive year in which Ontario's peak monthly demand occurred in the winter, at 13.58 TWh in January. Peak monthly demand in the Current Reporting Period occurred in July at 12.62

TWh. Both July and August (12.25 TWh) exceeded the Summer 2014 Period's peak monthly demand of 12.02 TWh which occurred in July 2014.[45]

Figure 1-21: Monthly Total Energy Withdrawals – Distributors and Wholesale Loads November 2010 – October 2015 (TWh)

Description:

Figure 1-21 charts the demand of two categories of consumers: market participants that are directly connected to the IESO-controlled grid other than distributors (Grid-Connected Consumers), and consumers connected to distribution systems (Distribution Level Consumers).



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

The breakdown of consumers into these two categories helps identify their respective monthly demand profiles.

[45] For more information regarding monthly Ontario demand in the Summer 2014 Period, see pages 44 – 46 of the Panel's October 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2014-Oct2014_20151008.pdf

Commentary and Market Consideration:

Seasonal change in Ontario demand is attributed almost entirely to Distribution Level Consumers. These include residential, small and medium commercial, and small industrial loads. The primary driver of demand for this consumer group is weather. Mild temperatures result in a reduced need for heating or cooling. April – May and September – October are typically the periods of lowest distribution-level demand. In the Current Reporting Period, however, demand in June (9.52 TWh) was very similar to demand in October (9.38 TWh) and was exceeded by demand in September (10.13 TWh), as June proved to be milder than September in 2015 in Ontario's most densely populated regions.

Meanwhile, demand from Grid-Connected Consumers, a group that is primarily comprised of industrial loads and large commercial consumers, which had been increasing slightly over the past five years, was down in the Current Reporting Period relative to the Summer 2014 Period.[46] Demand from Grid-Connected Consumers exhibits little of the seasonality seen with Distribution Level Consumers.

3 Supply[47]

During the second and third quarters of 2015, 408.5 MW of nameplate generating capacity completed commissioning and was added to the total installed generation capacity connected to the IESO-controlled grid. This new grid-connected capacity consists of wind (308.5 MW) and solar (100 MW) generation. At the end of the third quarter of 2015, grid connected generation capacity totalled 35,203 MW, consisting of nuclear (12,978 MW), gas-fired (9,934 MW), hydroelectric (8,462 MW), wind (3,234 MW), biofuel (455 MW) and solar (140 MW) generation.[48]

During the second and third quarters of 2015, 237 MW of nameplate generation capacity was added at the distribution level. This new distribution-level capacity (or 'embedded' capacity)

[46] For more information regarding monthly Ontario demand in the Summer 2014 Period, see pages 44 – 46 of the Panel's October 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2014-Oct2014_20151008.pdf

[47] For a more detailed examination of the medium-term supply capacity in Ontario, see the IESO's 18-month outlook, released in September 2016 and available at: http://www.ieso.ca/Pages/Participate/Reliability-Requirements/Forecasts-%26-18-Month-Outlooks.aspx

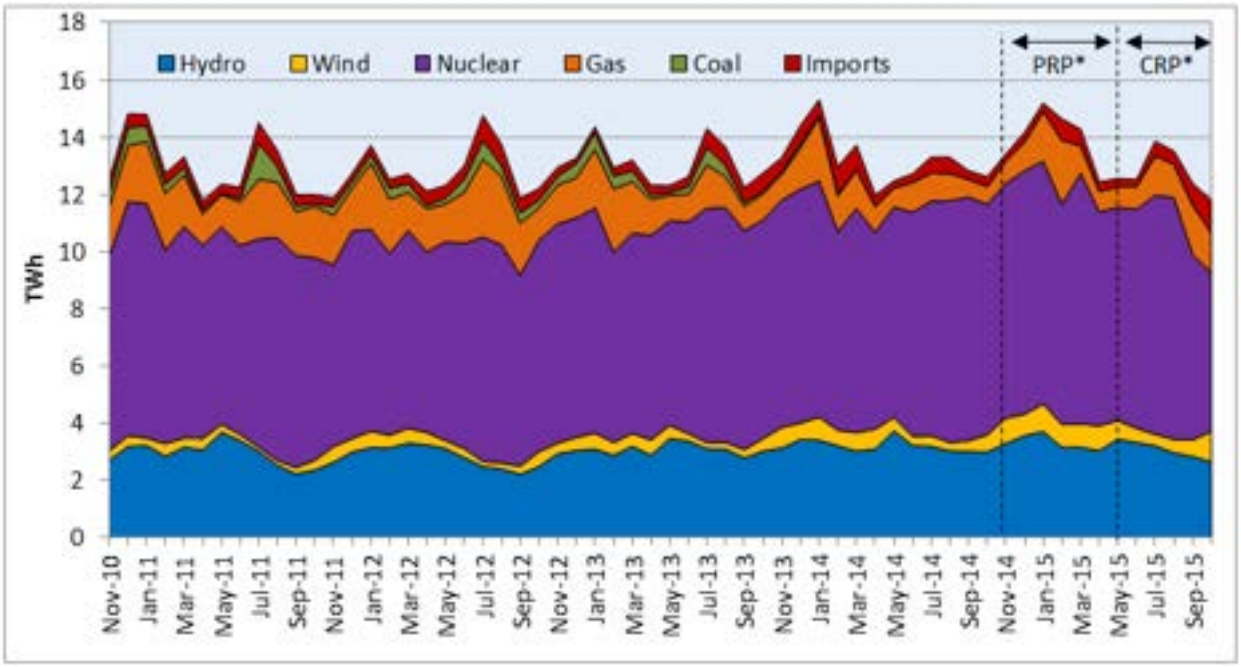
[48] Capacity totals were obtained from the Quarterly Ontario Energy Report as reported by the IESO. Added capacity totals were calculated from the 2015 Q1, Q2 and Q3 reports, available at: http://www.ontarioenergyreport.ca/index.php

consists of solar (132 MW), wind (59 MW), biofuel (19 MW), hydroelectric (16 MW), energy from waste (10 MW) and gas-fired and combined heat and power (1 MW). At the end of the third quarter of 2015, embedded capacity totalled 2,840 MW, consisting of solar (1,766 MW), wind (484 MW), hydroelectric (264 MW), gas-fired and combined heat and power (209 MW), biofuel (107 MW) and energy from waste (10 MW).[49]

Figure 1-22: Resources Scheduled in the Real-Time Market (Unconstrained) Schedule November 2010 – October 2015 (TWh)

Description:

Figure 1-22 illustrates the cumulative share of energy in the real-time unconstrained schedule from November 2010 to October 2015 by resource or transaction type: wind, coal-fired, gas-fired, hydroelectric, nuclear, and imports. Solar and biofuel are excluded from the figure as they contribute minimally to the total grid-connected resources scheduled in real-time.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

[49] Embedded capacity totals were obtained from the Quarterly Ontario Energy Reports as reported by the IESO. Added embedded capacity totals were calculated from the 2015 Q1, Q2 and Q3 reports, available at: http://www.ontarioenergyreport.ca/index.php.

Relevance:

This figure displays the evolution of Ontario's changing mix of real-time energy supply. Changes in the resources scheduled may be the result of a number of factors, such as changes in energy policy or seasonal variations (for example, during the spring snowmelt or 'freshet' when hydroelectric plants have an abundant supply of fuel).

Commentary and Market Considerations:

As previously noted throughout this chapter, there was a significant drop in nuclear output in the last two months of the Current Reporting Period due to planned outages. Nuclear production dropped from a high of 8.46 TWh in August to 5.76 TWh in October. Hydroelectric output also decreased over the course of the Current Reporting Period from a high of 3.42 TWh in May to a low of 2.63 TWh in October.

The remaining supply types combined to compensate for the decreased production from nuclear and hydroelectric resources in September and October: gas-fired generation produced 3.13 TWh– an increase of 1.71 TWh relative to the same two-month period in 2014 – and dispatchable wind and solar resources produced 1.7 TWh – an increase of 0.71 TWh relative to the same two-month period in 2014. Wind resources produced 1.07 TWh in October alone, the highest monthly output for those resources on record and the first time Ontario's wind fleet exceeded 1 TWh of production in a single month.

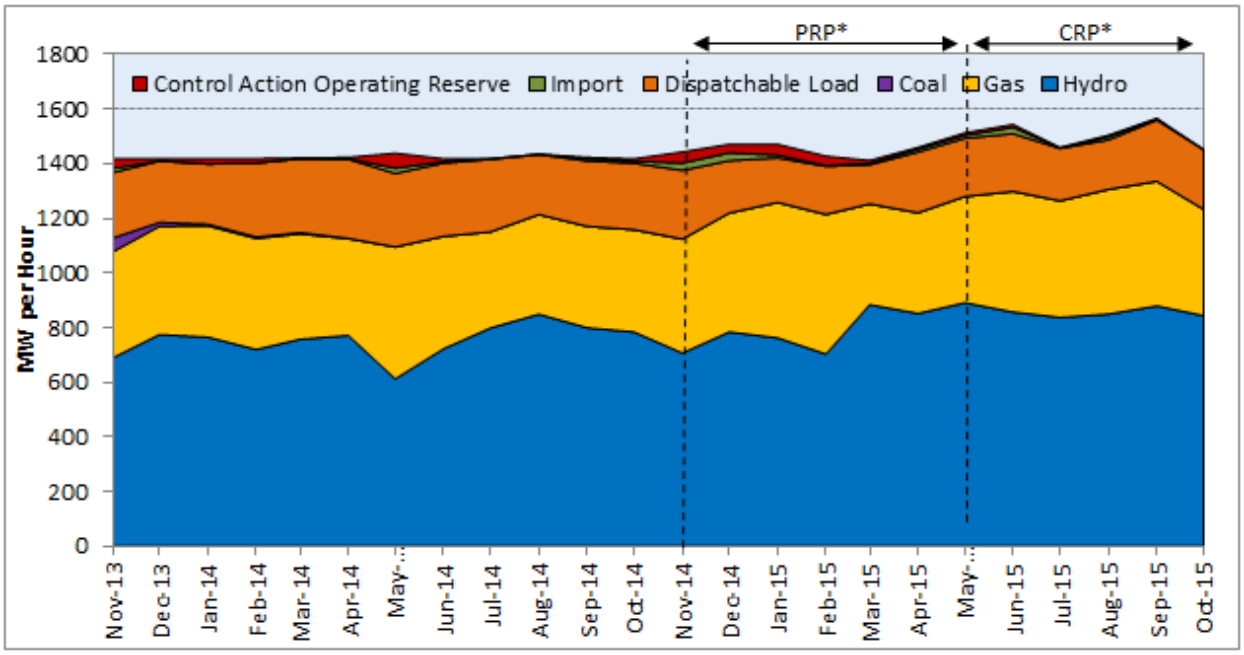
In September and October 2015, imports provided 1.89 TWh – an increase of 1.25 TWh relative to September and October of 2014 – and export demand was 1.54 TWh lower in September and October of 2015 relative to those months in 2014.[50]

[50] For more information on real-time scheduling by resource in the unconstrained sequence in the Summer 2014 Period, see pages 46 – 47 of the Panel's October 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2014-Oct2014_20151008.pdf

Figure 1-23: Average Hourly Operating Reserve
Scheduled by Resource or Transaction Type
November 2013- October 2015
(MW per hour)

Description:

Figure 1-23 plots the average hourly amount of OR in the unconstrained schedule from November 2013 to October 2015 by resource or transaction type: hydroelectric, gas-fired, coal-fired, imports, dispatchable loads and Control Action Operating Reserve (CAOR).[51] Changes in the total average hourly OR scheduled reflects changes in the OR quantity requirements.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

This figure reflects the evolution in Ontario's changing mix for OR supply as well as changes in the OR requirement over time. Changes in scheduled OR may result from a variety of factors

[51] CAOR is an out-of-market control action taken by the IESO when the market cannot provide enough supply to meet forecasted demand and reserve requirements. The IESO inserts standing offers in the OR offer stack that represent the IESO's ability to use 3% and 5% voltage reductions or forego the 30-minute OR requirement (under specific conditions) to meet OR needs. The offers have a pre-defined price and quantity and are only used in real-time, never in pre-dispatch.

such as changes in energy policy or seasonal variations, while changes to the OR requirement may result from changes in grid configuration and outages, among other factors.[52]

Commentary and Market Considerations:

The quantity of OR scheduled in the unconstrained sequence increased in the Current Reporting Period relative to the Summer 2014 Period,[53] from approximately 6.29 TWh to 6.68 TWh. In the Current Reporting Period it became increasingly common for the power flow on a major 500kV circuit connecting supply in Northern Ontario to demand in the South to exceed the capacity of Ontario's largest generation unit. In such instances, the circuit became Ontario's single largest contingency and increased the minimum OR requirement that the province was required to maintain. This situation tends to occur when demand in the province is higher and increasing quantities of supply in the North are required to meet demand in the South of the province. The increased frequency of a higher OR requirement corresponded with higher demand in the Current Reporting Period relative to the Summer 2014 Period (see the Commentary associated with Figure 1-20) and resulted in an overall increase in OR scheduled in the unconstrained sequence.

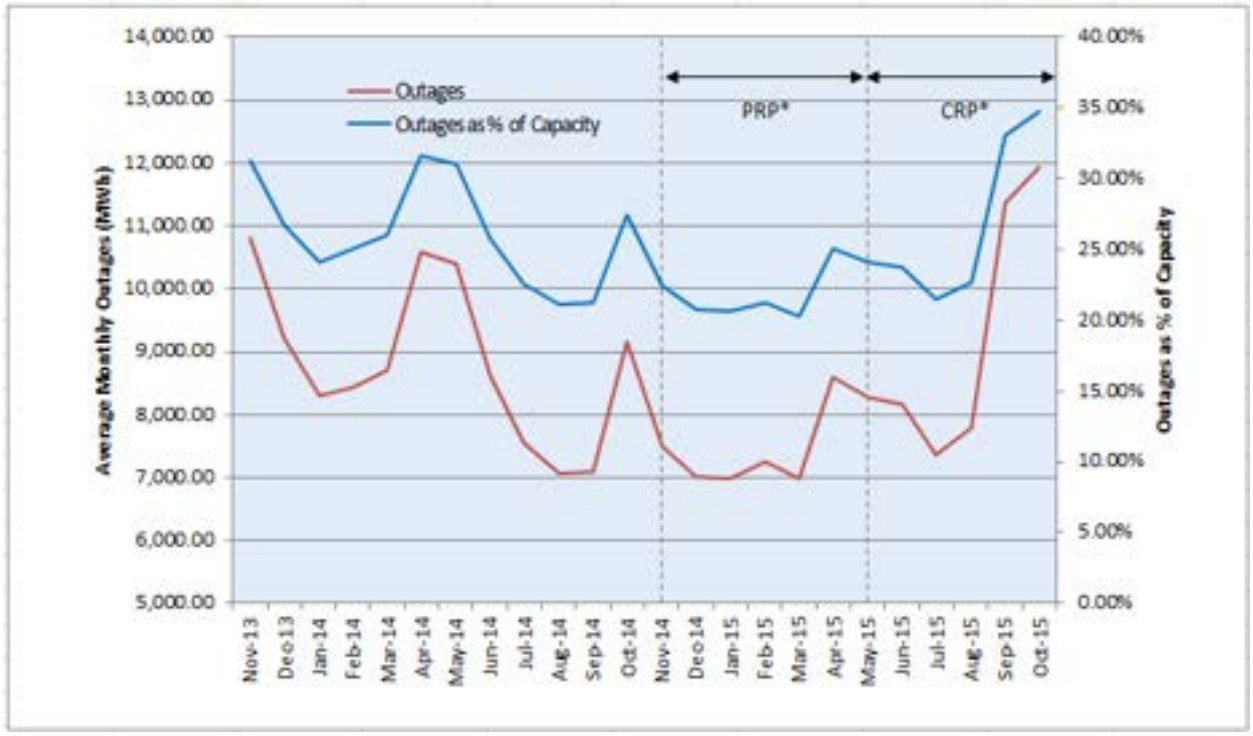
56.7% of all OR was supplied by hydroelectric resources, followed by gas-fired resources and dispatchable loads at 28.1% and 13.6%, respectively. Imports, biofuel and voltage reduction comprised the remainder of the OR supply mix, each contributing less than 6% of total supply.

[52] The total energy available from the 10-minute OR market must be enough to cover the single largest contingency in Ontario's electricity grid, with at least 25% of that energy available as 10-minute spinning reserve. The total energy available from the 30-minute OR market must be enough to cover half the second largest contingency on Ontario's grid.
[53] For more information regarding the average hourly OR schedule in the Summer 2014 Period, see pages 48 – 49 of the Panel's October 2015 Monitoring Report, available at:
http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2014-Oct2014_20151008.pdf

Figure 1-24: Unavailable Generation Relative to Capacity
November 2013 – October 2015
(% of capacity)[54]

Description:

Figure 1-24 plots the monthly averages of the hourly sums of unavailable generation capacity as a percentage of total grid-connected installed generation capacity from November 2013 to October 2015.[55] Unavailable generation capacity is comprised of capacity that s unavailable due to planned and forced (i.e. unforeseen) outages, derates, and operating security limits, as well as unscheduled capacity from intermittent, self-scheduling and transitional generators.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

[54] In previous reports, the Panel reported planned and forced outages and derates relative to capacity. The Panel has decided to report on all unavailable generation capacity, which is consistent with the IESO`s method for calculating unavailable capacity. The Panel is therefore now also including unscheduled capacity from self-scheduling resources and capacity that is made unavailable due to security limits on the high-voltage grid. As a result, the data reported in Figure 1-24 is not directly comparable with similar data published in previous Panel reports.

[55] Unavailable generation capacity data was obtained from System Status Reports published daily by the IESO. A simple monthly average was calculated using the most recently reported totals for each hour of each trade date. Daily, weekly and monthly market summaries published by the IESO are available at: http://www.ieso.ca/Pages/Power-Data/Market-Summaries-Archive.aspx.

Relevance:

Statistics regarding unavailable generation capacity provide an overview of how much of the time facilities in the province were able to provide supply, a key factor in the determination of market prices.

Commentary and Market Considerations:

There was a notable increase in unavailable generation capacity in the final two months of the Current Reporting Period, with total unavailable capacity reaching its highest totals of the period between November 2013 and October 2015. This was primarily attributable to the planned nuclear outages that occurred in the fall of 2015. September and October had the lowest monthly total outputs from Ontario's nuclear fleet in the Current Reporting Period at 6.52 TWh and 5.76 TWh, respectively, and had the highest totals of unavailable nuclear capacity (either planned or forced outages) at 2.93 TWh and 3.94 TWh, respectively.

4 Imports, Exports and Net Exports

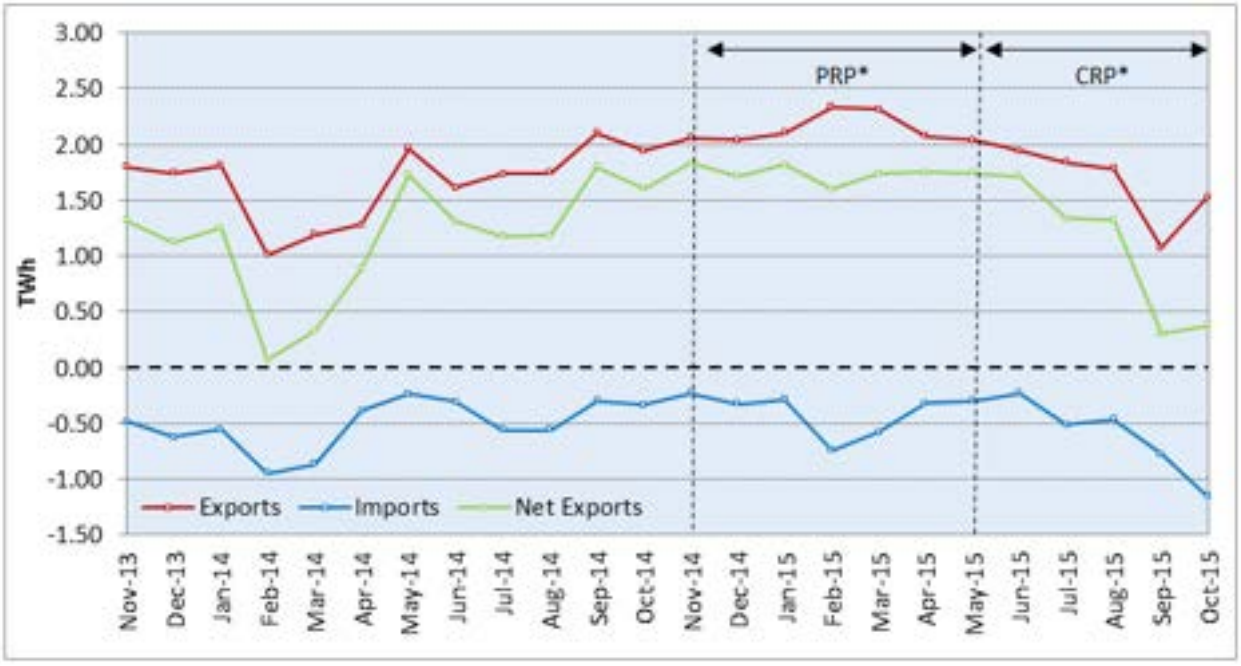
The data used in this section is based on the unconstrained schedules as these directly affect market prices. The unconstrained schedules may not reflect actual power flows.[56]

Figure 1-25: Total Monthly Imports, Exports & Net Exports (Unconstrained Schedule) November 2013 – October 2015 (TWh)

Description:

Figure 1-25 plots total monthly energy imports, exports and net exports from November 2013 to October 2015. Exports are represented by positive values while imports are represented by negative values.

[56] Although the constrained schedules provide a better picture of actual flows of power on the interties, they do not provide information on intertie congestion prices or to the Ontario uniform price (either in pre-dispatch or in real-time).



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

Imports and exports play an important role in determining supply and demand conditions in the province, and thus affect the market price. Tracking net export transactions over time provides insight into supply and demand conditions in Ontario relative to neighbouring jurisdictions. Periods of sustained net exports, such as the Current Reporting Period, indicate times of relative energy surplus in Ontario, while sustained periods of net imports, such as during the mid-2000s, indicate periods of relative scarcity.

Commentary and Market Considerations:

Ontario was a net energy exporter in each month of the Current Reporting Period, totalling 6.797 TWh. September and October were the second and fourth lowest net export totals of the two year period from November 2013 through October 2015 at 302 GWh and 380 GWh, respectively; two of only five months between November 2013 and October 2015 with monthly net export totals below 1.1 TWh, the others being February – April of 2014.[57]

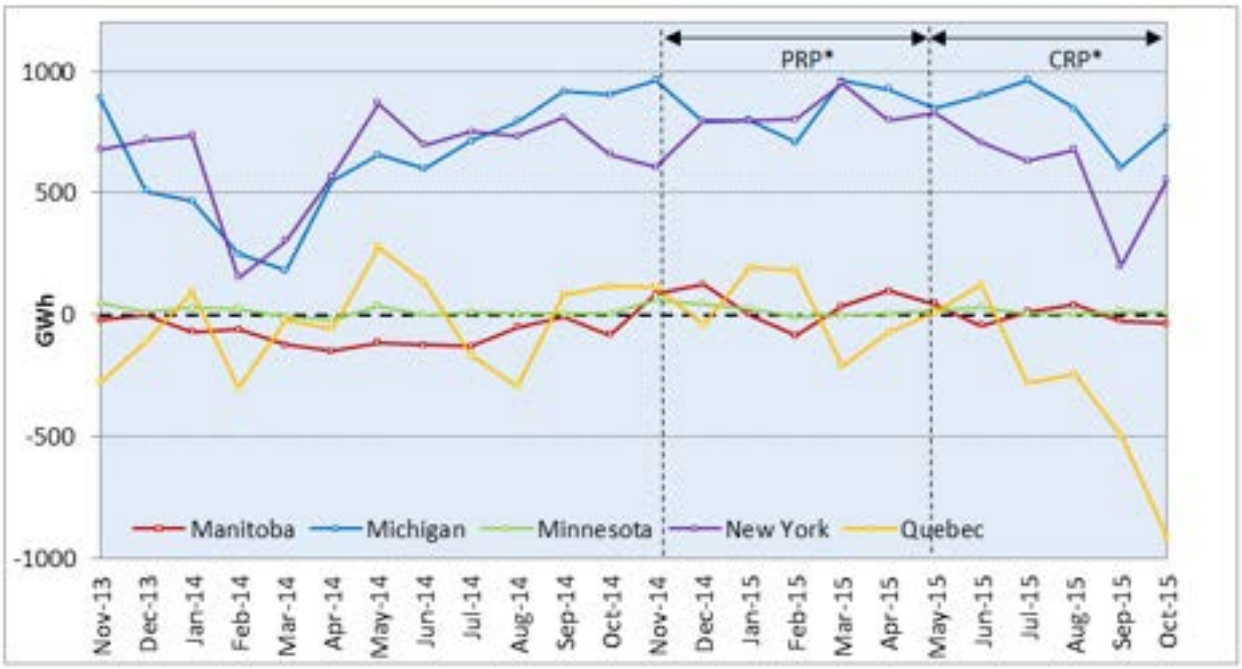
[57] For more information regarding monthly net exports in the Winter 2014 Period see pages 51-53 of the Panel's April 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2013-Apr2014_20150420.pdf

Total imports increased from 773 GWh in September to 1.151 TWh in October and total exports increased from 1.075 TWh in September to 1.531 TWh in October. Québec was the primary source of the increase in imports, while export demand increased at almost every interface relative to September (Minnesota being the sole exception). The largest change in net exports occurred at the New York interface, which went from 201 GWh of net exports in September to 553 GWh of net exports in October. Québec was a net importer in both months (401 GWh in September and 586 GWh in October).

Figure 1-26: Net Exports by Interface Group (Unconstrained Schedule)
November 2013 – October 2015
(GWh)

Description:

Figure 1-26 presents a breakdown of net energy exports from November 2013 to October 2015 to each of Ontario's five neighbouring jurisdictions: Manitoba, Michigan, Minnesota, New York and Québec. Net exports are represented by positive values while net imports are represented by negative values.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

This figure shows how Ontario's intertie trade evolves over time with each external jurisdiction.

Commentary and Market Considerations:

Ontario continued its historical trend as a net exporter to New York and Michigan throughout the Current Reporting Period and Minnesota maintained its position as a near net zero trader with Ontario.

Relative to the Summer 2014 Period, the most notable changes occurred in relation to Québec and Manitoba. Ontario was a net exporter to Manitoba in three of six months during the Current Reporting Period. Though Manitoba remained a net importer to Ontario, the total was down from 510 GWh in the Summer 2014 Period[58] to 8 GWh in the Current Reporting Period. Québec went from being a net exporter from Ontario of 0.153 TWh in the Summer 2014 Period[59] to a net importer to Ontario of 1.805 TWh in the Current Reporting Period.

Table 1-6: Average Monthly Export Failures by Interface Group and Cause (Constrained Schedule) November 2014 – April 2015 & May 2015 – October 2015 (GWh and %)

Description:

Table 1-6 reports average monthly export curtailments and failures over the Current and Previous Reporting Periods by interface group and cause. The failure and curtailment rates are expressed as a percentage of total (constrained) exports over each interface, excluding linked wheel transactions.[60]

[58] For more information regarding net exports in the Summer 2014 Period, see pages 50-53 of the Panel's October 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2014-Oct2014_20151008.pdf

[59] For more information regarding net exports in the Summer 2014 Period, see pages 50-53 of the Panel's October 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2014-Oct2014_20151008.pdf

[60] A linked wheel transaction is one in which an import and an export are scheduled in the same hour, thus wheeling energy through Ontario.

Interface Group	Average Monthly Exports (GWh)		Average Monthly Export Failure and Curtailment (GWh)				Export Failure and Curtailment Rate (%)			
			ISO Curtailment		MP Failure		ISO Curtailment		MP Failure	
	Current	Previous	Current	Previous	Current	Previous	Current	Previous	Current	Previous
New York	289.1	387.6	1.5	1.0	5.9	5.1	0.5	0.3	2.0	1.3
Michigan	333.8	410.8	1.2	3.7	4.7	4.9	0.4	0.9	1.4	1.2
Manitoba	37.4	40.8	3.2	3.3	11.7	4.8	8.5	8.2	31.1	11.7
Minnesota	8.2	9.1	0.4	0.4	0.2	0.3	5.0	4.4	2.9	2.8
Québec	92.5	187.2	1.4	13.3	0.4	1.9	1.5	7.1	0.4	1.0

Relevance:

Curtailment (ISO Curtailment) refers to an action taken by a system operator, typically for reliability or security reasons. Failure (MP Failure), on the other hand, refers to a transaction that fails due to a failure on the part of a market participant (such as an inability to obtain transmission service).

MP Failures and ISO Curtailments in respect of exports reduce demand between the hour-ahead pre-dispatch schedule and real-time. These short-notice changes in demand can lead to a sub-optimal level of intertie transactions given the market prices that prevail in real-time, and may contribute to SBG conditions. The IESO may be required to take mitigating control actions, such as dispatching down domestic generation or curtailing imports, to compensate for MP Failures or ISO Curtailments.

Commentary and Market Considerations:

Similar to both the Previous Reporting Period and the Summer 2014 Period, the Manitoba interface continues to be an outlier with respect to the percentage and absolute volume of ISO Curtailments and MP Failures. Manitoba continues to experience an increasingly higher percentage of MP Failures: 31.1% in the Current Reporting Period vs. 11.7% in the Previous Reporting Period, 28.3% in the Summer 2014 Period and 3.9% in the Winter 2014 Period.[61]

In absolute terms, MP failures at the Manitoba interface were more than double that at any other interface in the Current Reporting Period, despite the fact that Manitoba had the second lowest

[61] For more information regarding the export failures and curtailments in the Summer 2014 Period and the Winter 2014 Period see pages 53 – 54 of the Panel's October 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2014-Oct2014_20151008.pdf

average monthly export total. In terms of the percentage of MP Failures, exports failed at the Manitoba interface at a rate more than ten times greater than any other interface in the Current Reporting Period. The Manitoba interface also experienced the highest percentage and absolute volume of ISO Curtailments in the Current Reporting Period.

Table 1-7: Average Monthly Import Failures by Interface Group and Cause (Constrained Schedule November 2014 – April 2015 & May 2015 – October 2015 (GWh and %)

Description:

Table 1-7 reports average monthly import failures and curtailments over the Current and Previous Reporting Periods by interface group and cause. The MP Failure and ISO Curtailment rates are expressed as a percentage of total imports, excluding linked wheel transactions.

Interface Group	Average Monthly Imports (GWh)		Average Monthly Import Failure and Curtailment (GWh)				Import Failure and Curtailment Rate (%)			
			ISO Curtailment		MP Failure		ISO Curtailment		MP Failure	
	Current	Previous	Current	Previous	Current	Previous	Current	Previous	Current	Previous
New York	13.1	11.3	0.1	0.1	0.4	0.3	0.6	0.8	3.0	2.7
Michigan	5.4	14.5	0.1	1.9	0.6	0.9	1.6	13.1	10.4	6.1
Manitoba	21.0	20.7	3.5	2.9	0.1	0.2	16.8	14.0	0.5	0.8
Minnesota	1.4	1.1	0.1	0.2	0.1	0.1	4.9	21.0	4.2	9.0
Québec	136.1	123.7	5.9	4.0	0.5	0.4	4.3	3.3	0.3	0.3

Relevance:

MP Failures and ISO Curtailments in respect of imports represent a reduction in supply between the hour-ahead pre-dispatch schedule and real-time. This change in supply can lead to a sub-optimal level of intertie transactions and may contribute to increases in price. The IESO may be required to take mitigating control actions, such as dispatching up domestic generation or curtailing exports, to compensate for MP Failures and ISO Curtailments.

Commentary and Market Considerations:

Relative to the Previous Reporting Period, the percentage of ISO Curtailments of imports decreased at all interfaces except for Manitoba and Québec in the Current Reporting Period. The most significant decreases occurred at the Minnesota and Michigan interfaces. The percentage of ISO Curtailments and MP Failures at the Minnesota interface both reduced significantly despite an increase in average monthly imports; in absolute terms, however, only the ISO Curtailments were reduced. At the Michigan interface, the percentage of MP Failures increased despite a decrease in the absolute number of imports failed, as the average quantity of monthly imports experienced a greater decrease relative to the Previous Reporting Period. The absolute number of imports curtailed and percentage of ISO Curtailments increased at both the Manitoba and Québec interfaces in the Current Reporting Period.

Chapter 2: Analysis of Anomalous Market Outcomes

1 Introduction

This chapter examines market outcomes that fell outside of predicted patterns or norms during the period from May 1, 2015 to October 31, 2015 (the Current Reporting Period), with comparisons to the period from November 1, 2014 to April 30, 2015 (the Previous Reporting Period) and other periods as relevant. A reference to a "Summer Period" is to the period running from May 1 to October 31.

The Panel has established thresholds to signal an anomalous outcome for the Hourly Ontario Energy Price (HOEP), Operating Reserve (OR) payments, Congestion Management Settlement Credit (CMSC) payments, and Intertie Offer Guarantee (IOG) payments. Table 2-1 shows the number of anomalous price and uplift events that occurred in the Current Reporting Period and the preceding two Summer Periods.

Table 2-1: Summary of Anomalous Events during the 2013, 2014 and 2015 Summer Periods (Number of Occurrences)

Anomalous Event	May – October 2013	May – October 2014	May – October 2015
High HOEPs (above $200/MWh)	8	3	9
Negative HOEPs	224	656	371
OR Payments above $100,000/hour	6	0	15
CMSC above $1 million/day	8	1	0
CMSC above $500,000/hour	2	0	0
IOG above $1 million/day	0	0	0
IOG above $500,000/hour	0	0	0

Additionally, the Panel reports the five highest payments made under the IESO's Real-Time Generation Cost Guarantee (RT-GCG) and Day-Ahead Production Cost Guarantee (DA-PCG) programs. Payments made under these programs are recovered from consumers through uplift charges.

In the Previous Reporting Period there were 32 instances of anomalous OR payments, and the Panel reported on the increasing trend in OR prices.[62] In the Current Reporting Period there were 15 anomalous OR payments, well above the levels seen in previous Summer Reporting periods. One of those payments set a new record for the highest total hourly OR payments ever, with payments in that hour of over $1.7 million.

Section 2 describes how supply shortfalls in the energy market, which have increasingly occurred because of variable generation forecast errors, can lead to shortfalls in the OR market. High OR payments are a product of these shortfalls and signal the growing challenge of managing the system in the face of higher penetration of variable (wind and solar) generation. The Panel concludes that an increase in the frequency of anomalous OR payment events is an expected outcome given larger forecast errors and a decrease in OR offers.

The IESO has recognized that forecast errors create new challenges for system operations. Several of the anomalous payment events occurred when the IESO was unable to schedule sufficient OR to meet its OR requirement. The Panel is supportive of the IESO's efforts in the Enhancing System Flexibility stakeholder engagement to investigate options to address forecast errors associated with wind and solar generation.[63]. The Panel notes initiatives that are underway in other jurisdictions to address issues similar to those described in this chapter, which could help the IESO manage the impact of forecast errors on the energy and OR markets. A by-product of the forecast errors and the decrease in OR offers is the more frequent scheduling of Control Action Operating Reserve (CAOR) in the OR market. The Panel is recommending that the IESO review prices and offer quantities for CAOR to consider whether changes should be made to enhance efficiency of the OR market.

The remainder of the chapter discusses other anomalous events in the Current Reporting Period, as well as high RT-GCG and DA-PCG payments.

[62] See the Panel's May 2016 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2014-Apr2015_20160512.pdf
[63] For more information on this stakeholder engagement, see: http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/Enabling-System-Flexibility.aspx

2 Anomalous OR and HOEP Events

Table 2-2 lists the high HOEPs and anomalous OR payments during the Current Reporting Period, as well as the price for 10-minute spinning (10S) reserve in all of those hours. The two highest of such HOEP and OR payment events (the first and last events listed in Table 2-2) are described in greater detail in the next section.

Table 2-2: High HOEP and Anomalous OR Payment Events
May 1, 2015 to October 31, 2015
($)

Date	Delivery Hour	HOEP ($/MWh)	10S OR Price ($/MW)	OR Payments ($)	Threshold Exceeded	
					HOEP	OR
05/05/2015	**16**	$1,255.89	$1,231.36	$1,736,895.51	✓	✓
05/05/2015	**21**		$149.91	$176,079.68		✓
05/05/2015	**22**		$94.51	$133,315.59		✓
06/05/2015	**20**		$162.48	$146,930.24		✓
08/05/2015	**20**	$243.80	$247.43	$294,190.06	✓	✓
09/05/2015	**17**		$92.04	$118,520.78		✓
11/05/2015	**13**		$169.34	$219,576.56		✓
30/05/2015	**11**		$120.71	$126,688.95		✓
30/05/2015	**16**	$211.93	$201.29	$219,785.13	✓	✓
12/06/2015	**8**	$200.08	$86.29		✓	
14/06/2015	**17**	$321.48	$237.45	$217,646.34	✓	✓
15/06/2015	**22**		$65.21	$107,917.63		✓
15/06/2015	**23**		$69.19	$122,212.86		✓
02/08/2015	**16**	$371.76	$256.34	$284,112.31	✓	✓
02/08/2015	**17**	$254.27	$187.20	$225,183.38	✓	✓
07/09/2015	**20**	$251.73	$81.43		✓	
02/10/2015	**9**	$1,053.11	$961.18	$1,047,728.54	✓	✓
Total				**$5,176,783.90**	**9**	**15**

The high HOEPs and anomalous OR payments in the Current Reporting Period are associated with short-lived scarcity events during which the IESO dispatched more expensive energy to deal with differences between actual and forecast supply and demand.

Operating Reserve (OR) Requirement

All electricity system operators are required to maintain sufficient operating reserves to respond to contingencies on the grid: if the largest generator or heaviest-loaded transmission line trips, the operator must have enough operating reserve to ensure that the system remains stable.

OR is categorized according to the time it takes for generators to provide the required energy. Ten minute reserves can provide the required energy within ten minutes of receiving a dispatch. These reserves are of two types: spinning (synchronized with the grid) (10S) and non-spinning (not synchronized with the grid (10N). Thirty minute reserves (30R) can provide energy within 30 minutes of receiving a dispatch (and are not synchronized).

The IESO must operate with sufficient 10-minute OR to cover the single largest contingency (transmission line or generator) at any time. A portion of this requirement is met through 10S (typically 25% or more), and the remainder is met through 10N. The IESO must also procure sufficient 30R to cover half of the second largest contingency (or the largest commissioning generator, as a commissioning generator has a higher risk of tripping offline).*

When OR is dispatched to provide energy, reliability standards require ISOs to schedule additional OR to meet the standard and recover from any shortage within 90 minutes (105 minutes if OR was activated to respond to a contingency). In certain cases ISOs are permitted to operate without sufficient 30R for up to 4 hours.

The IESO's Market Rules define the circumstances under which the IESO can deploy OR (see section 4.5 of Chapter 5 of the Market Rules):

- Cover or offset unanticipated increases in load during a dispatch day or dispatch hour;
- Replace or offset capacity lost due to the forced outage of generation or transmission equipment; or
- Cover uncertainty associated with the performance of generation facilities or dispatchable loads in responding to the IESO's dispatch instructions.

*The IESO's OR requirement is determined in accordance with standards set by the North American Electric Reliability Corporation (NERC) and the Northeast Power Coordinating Council (NPCC).

As levels of variable generation capacity increase, greater differences between forecast and actual supply can arise than has occurred historically. These differences arise when variable generation connected to the IESO-controlled grid is more or less than forecast, contributing to supply forecast errors, or when variable generation connected at the distribution level (embedded) is more or less than forecast, contributing to forecast errors in demand on the IESO-controlled grid.

Although other factors also contribute to supply and demand forecast errors (for example, forced outages), the growth in variable generation capacity is a major factor contributing to the

increasing magnitude of these forecast errors. Table 2-3 reports wind production and shortfalls (the average and maximum amounts by which wind production is less than forecast). The largest wind shortfall has increased from 581 MW in 2012 to over 1,000 MW in 2015.

Table 2-3: Hourly Average and Maximum Wind Production and Shortfalls
January 1, 2012– December 31, 2015
(MW and MWh)

Year	Production		Shortfall	
	Average (MWh)	Maximum (MWh)	Average (MW)	Maximum (MW)
2012	522.94	1627.60	104.08	581.60
2013	588.18	1967.70	85.92	518.90
2014	755.18	2687.80	105.96	713.10
2015	1007.94	3475.00	123.81	1032.40

The purpose of OR is to ensure that sufficient capacity is available to respond to differences between forecast and actual supply and demand, including shortfalls caused by contingencies, but the OR requirement is based only on the size of potential contingencies (see the text box above). The increase in variable generation has added to the magnitude of the difference between forecast and actual supply and demand, which in turn has increased the number of hours in which less OR can be scheduled than is called for by the OR requirement (an OR shortfall). An OR shortfall often produces anomalous OR payments. [64]

OR shortfalls have occurred with increasing frequency. Table 2-4 shows the number of intervals (one interval is 5 minutes) in which the IESO has scheduled at least 5 MW less than the ten-minute OR requirement. These occurrences have increased from fewer than 100 in 2012 to 525 in 2015. While OR shortfalls still occur relatively infrequently, it seems prudent to review whether the increasing trend in OR shortfalls poses a risk to reliability.

[64] Reliability standards permit the IESO to operate with less OR scheduled than the OR requirement, as long as OR schedules are returned to the OR requirement within certain timeframes (which are defined in the reliability standards--see text box above).

Table 2-4: OR Requirement Shortfalls
January 1, 2012– December 31, 2015
(Number of intervals)

Year	Ten minute OR shortfalls larger than 5 MW
2012	90
2013	92
2014	179
2015	525

The increase in forecast errors, coupled with a relative decrease in the total quantity of OR offers have both contributed to higher OR prices (and, in some cases, to OR shortfalls).

2.1 Examples of Large Variations Leading to Scarcity of Dispatchable Capacity

This section illustrates how supply and demand forecast errors in the energy market can lead to shortfalls and high prices in the OR market, using two examples from the Current Reporting Period. In both examples, additional energy needed to be dispatched in real-time when variable supply was less than forecast or real-time demand was higher than forecast. In the first example, wind generation produced less than forecast; in the second example, actual demand was higher than forecast and the IESO experienced a contingency event that required the activation of OR. In both cases, the dispatch of additional energy to make up for the supply shortfall led to insufficient OR remaining to meet the OR requirement and resulted in an OR shortfall and high OR prices. During the OR shortfall events, the price in the energy and OR markets cleared just under the maximum market clearing price of $2000.

2.2 Highest HOEP and OR payments When Wind Production Shortfall Leads to OR Requirement Shortfall

On Tuesday, May 5, 2015, a storm front moving across Ontario led to wind production being 490 MW less than forecast in pre-dispatch in hour ending (HE) 16, which in turn led to a 73 MW OR shortfall and energy and OR prices of over $1,200/MWh for the hour. Table 2-5 presents market data for this event.

Table 2-5: Market Data
Tuesday May 5, 2015, HE 16
(MW and $)

HE 16 on Tuesday May 5, 2015	
Wind Shortfall	490 MW
Total OR Payments	$1,736,895.51
HOEP	$1,255.89 / MWh
10S OR Price	$1231.40 / MW
30R OR Price	$1206.10 / MW
OR Shortfall	73 MW

The IESO noticed early in the day that wind forecast information was not being updated accurately due to an IT issue. The IESO noted that the forecast for HE 16 was 600 MW, but that wind production had been decreasing since its peak of 400 MW at 12:30. In HE 16, wind production was 490 MW less than pre-dispatch forecasts. This wind shortfall required that additional energy be dispatched in real-time.

In addition, a change in transmission line flows increased the size of the largest contingency on the system by 150 MW, which increased the OR requirement to 1,650 MW.[65] Both the wind forecast error and the increase in the OR requirement required the IESO to dispatch more resources to meet energy demand and the OR requirement; however, there were insufficient OR offers available to meet the OR requirement, resulting in an OR shortfall of 73 MW from interval 5 to interval 11 of HE 16.

[65] Such an increase in the OR requirement occurs often during the afternoon.

Figure 2-1: OR Schedules and 10S Price
Tuesday May 5, 2015, HE 16
(MW and $/MW)

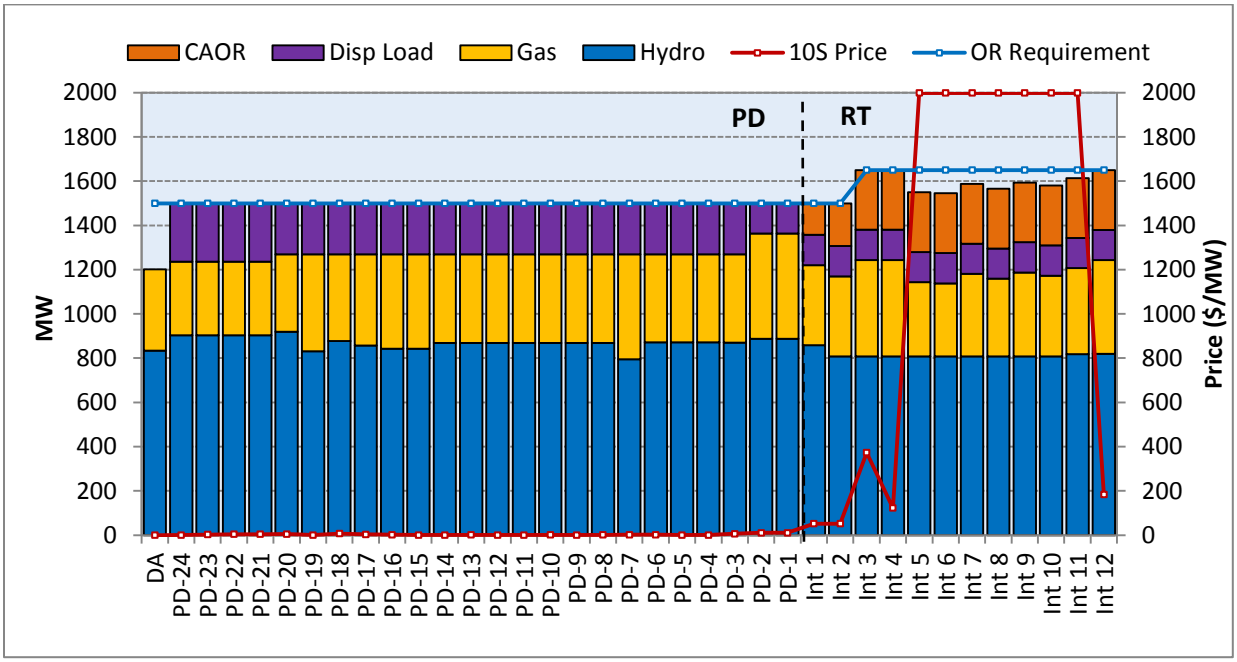


Figure 2-1 illustrates the OR schedules for this hour, beginning in the day-ahead, through pre-dispatch and then every five minutes (interval-by-interval) throughout the hour (OR schedules illustrated represent the total 10S, 10N and 30R schedules). The reduction in the OR scheduled from hydroelectric and gas resources in Figure 2-1 reflect how these resources were dispatched to provide energy in response to the 490 MW wind shortfall. In order to meet energy demand, the IESO scheduled a dispatchable load that offered at $1,999/MWh. To replace these resources and maintain OR at prescribed levels, the IESO had called on all available OR offers as well as relying on CAOR, but this was not enough to avoid an OR shortfall. When there is an OR shortfall, the OR price for all three categories of OR is equal to the energy market price, in this case $1,999/MWh.

2.3 High HOEP and OR Payments When a Contingency Coincided With Demand Forecast Error

The second highest HOEP and OR payments in the Current Reporting Period occurred in HE 9 on October 2, 2015, when there was a loss of 800 MW of generation capacity just prior to the

hour. In addition to the sudden supply loss, actual demand in HE 9 was approximately 600 MW higher than was forecast in pre-dispatch. Table 2-6 presents market data for this event.

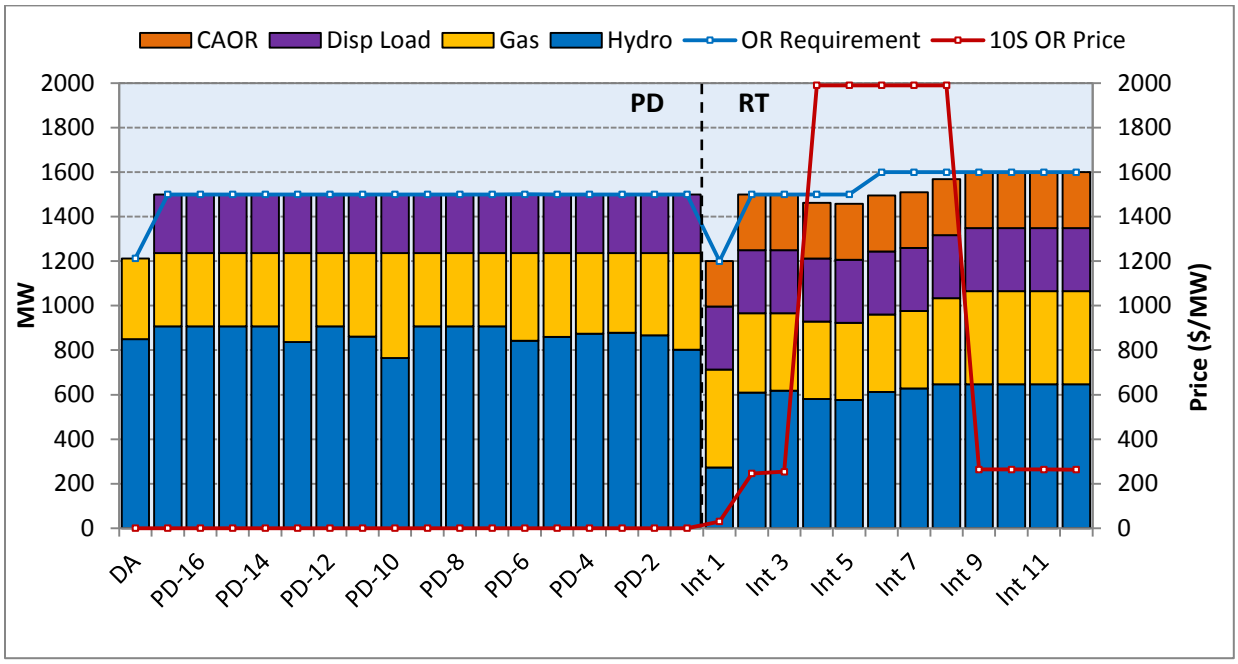
Table 2-6: Market Data
Friday October 2, 2015, HE 9
(MW, $/MW, $/MWh and $)

HE 9 on Friday October 2, 2015	
Loss of Generation Capacity	800 MW
Demand Forecast Error	600 MW
OR Activated (SAR)[67]	600 MW (425 MW)
10S OR Price	$961.2/MW
30R OR Price	$961.1/MW
OR Shortfall	61 MW
Total OR Payments	$1,047,728.54
HOEP	$1,053.11/MWh

In response to the loss of generation the IESO activated[66] 600 MW of OR and 425 MW of Simultaneous Activation Reserve .[67] Between the end of HE 8 and the beginning of HE 9, approximately 500 MW of OR from hydroelectric facilities and 100 MW of OR from gas-fired facilities were activated to provide energy. Figure 2-2 illustrates the OR schedules for HE 9.

[66] When OR is used to respond to a contingency, OR is "activated" to provide replacement energy (as compared to OR resources being economically dispatched in response to shortfalls from forecast errors). When OR is activated, the OR requirement is temporarily reduced by the size of the activation; when OR resources are economically dispatched to provide energy, the OR requirement does not change.
[67] Simultaneous Activation Reserve is an arrangement that allows some members of the eastern interconnection to share in the activation of operating reserves in the event of a significant loss of generation.

Figure 2-2: OR Schedules and 10S Prices
Friday October 2, 2015, HE 9
(MW and $/MW)



When OR was activated just prior to HE 9, the OR requirement was temporarily adjusted down from 1500 MW to 900 MW and was restored to 1500MW once the IESO recovered from the contingency (in interval 2 of HE 9). The OR requirement was then further increased to 1600 MW in interval 6, when changes in transmission line flows increased the size of the largest contingency.

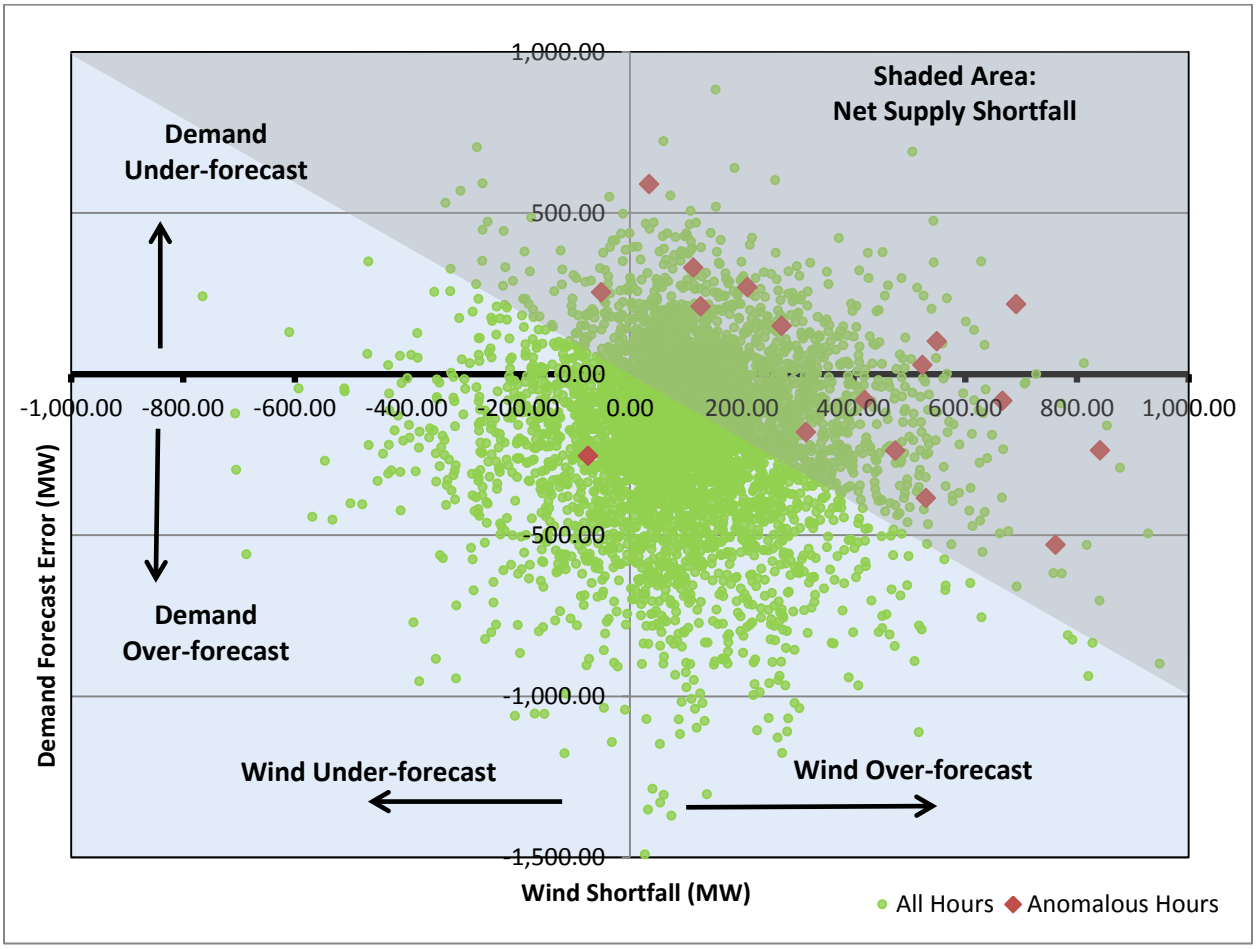
Following the OR activation, the IESO called on additional resources to provide OR and energy, but there were not enough OR offers to meet the OR requirement. This led to an OR shortfall of approximately 61 MW from interval 4 to interval 8. As noted earlier, when there is an OR shortfall the OR price for all three categories of OR is equal to the energy market price. The energy price during these intervals was set by a dispatchable load at $1999/MWh, as was the case on May 5, 2015.

2.4 Differences Between Forecast and Actual Supply and Demand can Lead to Scarcity

As shown in Figure 2-3, all but one of the High HOEP and anomalous OR payment events in the Current Reporting Period occurred when the IESO experienced a supply shortfall. Specifically,

the IESO experienced a scarcity of dispatchable capacity in the energy and OR markets in real-time. Since forecast errors only emerge in real-time, the IESO is forced to call on more expensive resources. In some cases there is insufficient dispatchable capacity online and there are shortfalls in the OR market. There were many other instances in the Current Reporting Period when the IESO experienced a shortfall in forecast supply, but there was sufficient dispatchable capacity available to avoid High HOEPs or anomalous OR payments.

Figure 2-3: High HOEPs and Anomalous OR Payment Events
May 1, 2015 to October 31, 2015
(MW)



High prices provide a signal of scarcity that should generally encourage a market response, but since the high resulting from forecast errors do not emerge until real-time there is limited ability for most participants to respond. The next section examines the supply of OR to assess the market response and options for enhancing the market response.

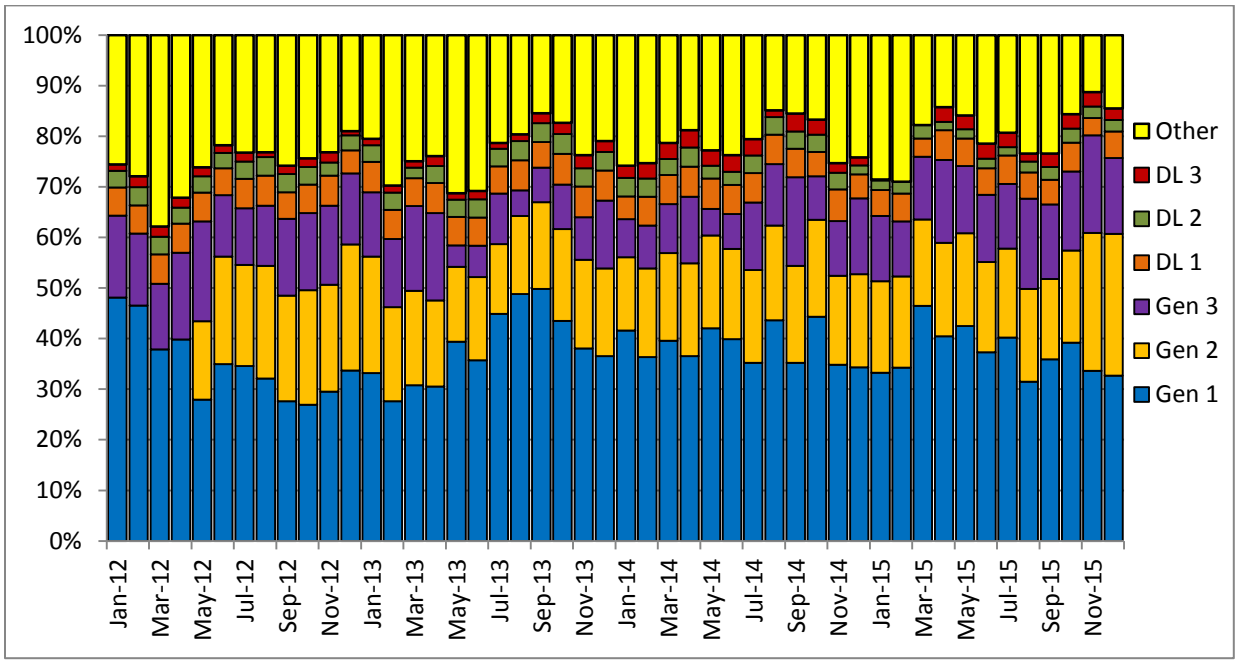
2.5 Forecast errors put more strain on OR supply

The IESO dispatches more expensive resources to provide energy and OR in response to differences between forecast and actual supply and demand. Changes on the supply side of the OR market have contributed to a more frequent incidence of higher prices and more frequent scheduling of CAOR.

The IESO operates the OR market by dispatching offers from market participants that offer OR. Twenty-five market participants have consistently offered into the OR market between January 1, 2012 to December 31, 2015, with the three largest scheduled to provide an average of more than 65% of OR supply. In some months, these three suppliers have been scheduled for as much as 80% of OR supply.

Figure 2-4 displays the share of all OR suppliers from January 2012 to December 2015, by scheduled MWs. Aside from the three largest suppliers, the next three OR suppliers (all dispatchable loads) have supplied an average of 10% of OR supply over this time period. The "other" category includes all other resources, which individually each contribute less than 5% of OR supply.

Figure 2-4: OR Market Participant's Market Share by Scheduled MWs
January 1, 2012- December 31, 2015
(% of Total Share)



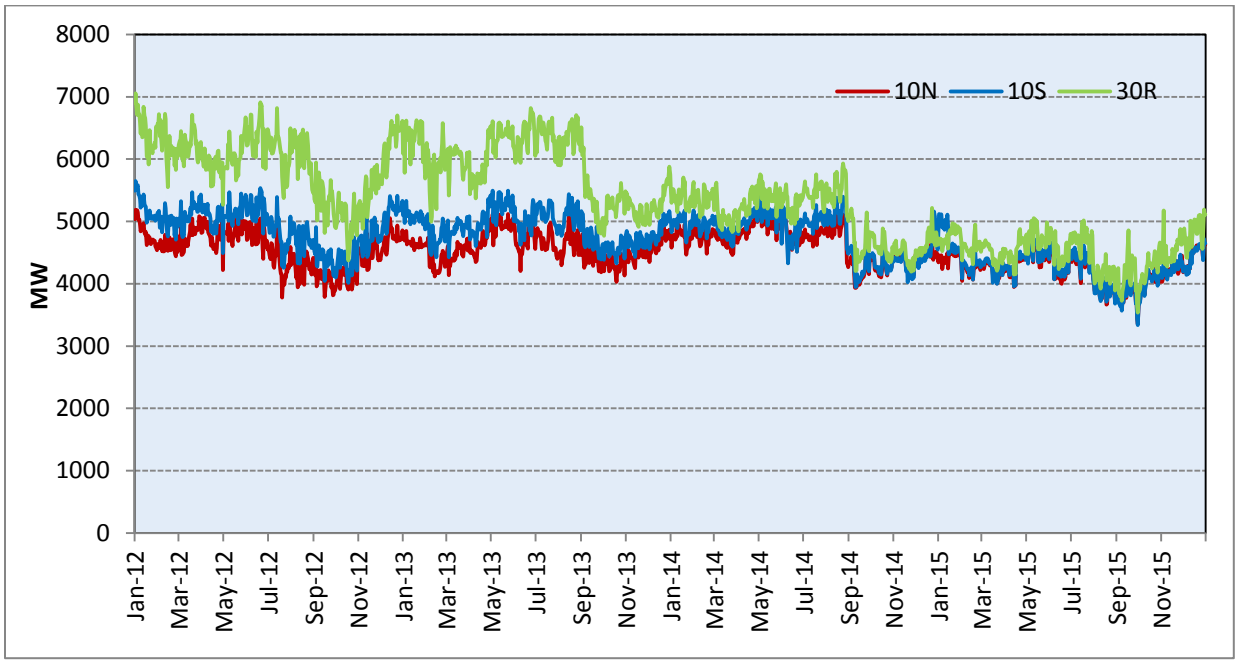
2.6 Reduction in Total Offers of OR

In general, OR offers are informed by the opportunity cost of not supplying energy. Physical limitations may affect the ability of some generators to supply OR in some cases. For example, limits on river systems may affect the ability of some hydro units to change their production on short notice. Moreover, the largest OR supplier (OPG) is indifferent to the amount of OR revenues that it receives from the market because OR revenue has been subtracted from its revenue requirement when the OEB sets payment amounts for its hydroelectric facilities. Other resources that offer into the OR market are able to profit from OR prices, and offer into the OR market accordingly.[68]

Total offers into the OR market have decreased relative to historic levels. Figure 2-5 shows the average hourly OR offers into all three categories of OR, from January 1, 2012 to December 31, 2015.

[68] In contrast to OPG's regulated hydro resources, generators who are eligible for the IESO's RT-GCG program currently do not have their guaranteed costs offset by OR revenue at all. See Chapter 3 in this report for more detail.

Figure 2-5: Total OR Offers
January 1, 2012- December 31, 2015
(MW)



2.7 Control Action Operating Reserves are Scheduled More Frequently

The reduced volume of OR offers, combined with larger magnitude and frequency of forecast errors, has resulted in more frequent scheduling of Control Action Operating Reserves (CAOR) in the OR market. This is a sign of stress on the OR market.

CAOR is always offered in the OR market and when scheduled it replaces more expensive OR offers. CAOR is offered into the OR market like other energy-producing (or load-reducing) resource, but "control actions" involve the IESO reducing voltage (thereby reducing demand) or scheduling less 30-minute OR than is required for up to four hours. When CAOR is scheduled for OR, it does not mean the IESO will necessarily take those actions; [69] scheduling CAOR allows the IESO to schedule less OR from other resources, enabling the IESO to dispatch those resources into the energy market.

[69] CAOR is offered into the energy market at $2000, so in the event energy is required the IESO will dispatch energy from other resources before taking control actions.

Two categories of CAOR resources are offered into the OR market, 3VR and 5VR:

- 3VR offer: 400 MW at $30.10/MW
- 5VR offer: 200 MW at $75/MW and 200 MW at $100/MW

Table 2-7 shows the number of intervals in which 3VR and 5VR CAOR resources have been scheduled over the past 5 years. The number of intervals in which CAOR is scheduled has increased in frequency in recent years, from less than 200 intervals to over 5000 intervals in 2015 for the 3VR resource, and over 400 intervals in 2015 for the 5VR CAOR resource.

Table 2-7: Number of Intervals with CAOR Schedules
January 1, 2012 – December 31, 2015
(Number of intervals in unconstrained schedule)

Year	3VR	5VR
2010	154	115
2011	2,419	261
2012	1,285	96
2013	9,860	413
2014	9,449	397
2015	5,879	406

In 2011 the IESO reviewed its CAOR offers in stakeholder engagement 72 (SE-72).[70] The IESO launched this engagement to review the impact of CAOR offers in the OR market, stating that:

> "To establish CAOR prices, the historical frequency of control actions was used as an initial reference. As time progressed and market conditions changed the historical frequency reference point for setting the price for CAOR should be reconsidered. As such, the IESO in consultation with stakeholders is proposing to define a set of principles to re-evaluate the pricing for CAOR."[71]

The IESO closed SE-72 without changing the pricing of CAOR offers, stating that that the "efficiencies identified in the review did not warrant implementing changes to the CAOR standing offers."[72] At that time CAOR was scheduled less than half as often as it is today: given the more frequent scheduling of CAOR, the IESO may come to a different conclusion about the

[70] http://iesoqa-public.sharepoint.com/Pages/Participate/Stakeholder-Engagement/SE-72.aspx
[71] For more information, see http://iesoqa-public.sharepoint.com/Documents/consult/se72/se72-20110505-position_paper.pdf.
[72] For more information, see http://iesoqa-public.sharepoint.com/Pages/Participate/Stakeholder-Engagement/SE-72.aspx

efficiency gains available from making changes to CAOR offer prices. It might be beneficial to offer CAOR at escalating prices (comparable to an OR demand curve) rather than in large blocks in order to signal a need for additional OR offers as CAOR capacity is exhausted. Changes to CAOR offers could be used to set an OR demand curve (as initially considered in SE-72), which would help send a signal of increasing scarcity as more of this resource is scheduled.

Furthermore, the IESO's standing offers for CAOR may offer more capacity into the market than is actually available. The IESO subsequently reduces this quantity (or derates this capacity) in either day-ahead (3VR) or real time (5VR). Since the 5VR CAOR offers are derated only once they are scheduled, this change in availability is only reflected in the market when this capacity is actually needed. The Panel recommends that the IESO revisit the standing CAOR offer quantities.

Recommendation 2-1

Given the number of recent changes in the operating reserve market, the Panel recommends that the IESO review whether the real-time operating reserve prices transparently reflect the value of operating reserve as more Control Action Operating Reserve capacity is scheduled, and whether changes to Control Action Operating Reserve offer quantities and prices could enhance the efficiency of the operating reserve market.

2.8 Other North American ISOs are Facing Similar Challenges Managing Forecast Errors

The issue of greater variability between forecast and actual supply and demand driven by increasing production from wind and solar generators is one that other jurisdictions are also experiencing.

For example, similar to the analysis for Ontario presented in this chapter, situations have occurred in California where the ISO lacks sufficient dispatchable capacity to deal with supply and demand forecast errors. The California Independent System Operator (CAISO) has experienced:

> "…numerous instances in which … commitments are rendered infeasible due to load forecast error, generation variability, intertie changes. These instances pose reliability

> concerns because to the degree the ISO must re-dispatch resources in real-time and there is insufficient committed resource flexibility the ISO may be drawing on operating reserves, regulation or on the interconnection."[73] (Emphasis added)

The Midcontinent Independent System Operator (MISO) has also experienced scheduling shortfalls in their OR market similar to those examined in this chapter:

> "Deviations from expected net load or high rates of change … can leave dispatchable resources … without ramp capability to respond, which can lead to short-term scarcity events. The [proposed] approach manages the ramp capability from controllable resources … in a way that better positions them to be able to respond to variations and uncertainty in the forecasts from the various non-controllable assets in the system such as the load, intermittent generators, and net scheduled interchange."[74] (Emphasis added)

This issue is sufficiently common among ISOs that the North American Electric Reliability Corporation (NERC) has remarked:

> "… the Operating Reserve practices of the Balancing Authorities in the United States and Canada enable them to accommodate the current amounts of variable generation penetration. However, many Balancing Authorities may need to change their practices to increase amounts of Operating Reserves to match anticipated increases in variable generation integration. For example, this may include adding additional Ancillary Service products."[75]

Although Ontario will require its own solution, it is instructive to observe that the additional ancillary service products referred to in the quote are currently under development in some other North American jurisdictions. For example, CAISO is in the process of revising their scheduling algorithms to schedule more capacity when the conventional dispatch mechanisms do not schedule sufficient capacity to manage the uncertainty associated with production from variable

[73] For more information, see: http://www.caiso.com/Documents/TechnicalBulletin-FlexibleRampingConstraint_UpdatedApr19_2011.pdf
[74] See https://www.misoenergy.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/Ramp%20Capability%20for%20Load%20Following%20in%20MISO%20Markets%20White%20Paper.pdf at page 2.
[75] For more information, see: http://www.nerc.com/files/ivgtf2-3.pdf at page 10.

generators. Similar to OR, the ISO schedules standby capacity, but that capacity is scheduled based on the uncertainty of output from variable generators (whereas OR is scheduled based on the size of potential contingencies). This change provides the ISO with additional means to manage variability in supply and demand, without relying solely on resources scheduled to deal with contingencies.

Although each jurisdiction is unique, the issue of managing the increasing unreliability of supply associated with variable generation is one that is having an impact on operating reserve markets across North America. Other ISO's have adopted changes to their market and scheduling systems to deal with the impact.

2.9 Market Design Changes are needed to Keep Pace with Ontario's Evolving Resource Mix

Given the recent and planned increases in variable generation capacity in Ontario, it is likely that forecast errors will continue to increase in size. Not only is this likely to lead to a higher frequency of unforeseen high prices in real-time, but it also creates new risks for the system operator to manage to maintain reliability. The IESO has recognized that forecast errors from variable generation have created new challenges for system operations. The IESO recently completed an operability assessment and identified that there is a need for "additional response capability to manage potential over-forecast of wind/solar output."[76] This conclusion is consistent with the Panel's observations and analysis.

As a result of the operability study, the IESO has launched a stakeholder initiative to identify potential options for acquiring additional response capability.[77] The IESO has indicated that the development of these options is to be coordinated with the IESO's Market Renewal stakeholder engagement. In the Panel's view this is appropriate: how to acquire the most cost-effective response capability is precisely the type of question the Market Renewal initiative should be addressing.

[76] For more information, see: http://www.ieso.ca/Documents/consult/sac/SAC-20160511-Operations-Update.pdf at slide 6.
[77] For more information, see: http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/Enabling-System-Flexibility.aspx.

A properly functioning market should signal a need and enable market participants to respond. In the circumstances described in this chapter, the IESO-administered markets are indicating scarcity conditions in real-time and signalling a need for flexible resources. Responses to this need could range from grid energy storage, demand response, enabling simple cycle operation at combined cycle plants, or adding additional flexible generation, among others. In the Panel's view, the more the IESO-administered markets enable participants to compete to provide the appropriate response the less need there is for the IESO to direct solutions.

Market design changes will be needed to support the appropriate market response. In the Market Renewal stakeholder engagement the IESO has argued that now is the time to modernize because "market mechanisms with transparent price signals have proven critical in effectively bringing suppliers and consumers together, allocating risk, and supporting efficient decision making."[78] The Enabling System Flexibility stakeholder engagement has identified the need to develop a comprehensive solution, in line with the principles of maintaining reliability, being cost-effective, competitive, transparent, stable, sending efficient price signals, scalable to system needs and technology neutral.

More frequent intertie scheduling is one example of a market design change that would help meet this need and satisfy the IESO's stated principles. Allowing intertie schedules to adjust during the hour (currently, intertie schedules are fixed for an hour) would allow traders to respond to changing conditions and provide the IESO with additional dispatch flexibility. Since Ontario is often a net exporter, if supply shortfalls emerge when Ontario is exporting, higher prices would cause export demand to fall within the hour, helping to reduce or eliminate the shortfall. The Panel encourages the IESO to include more frequent intertie scheduling as an option in allowing a market response to variable generation forecast errors, and assess how additional market design changes can meet the identified need at the lowest cost.

The proposed changes being considered in the IESO's Enabling System Flexibility initiative are needed in advance of the planned growth in variable generation. In light of the fact that operating reserves are required to maintain system reliability, and that variable generation forecast errors

[78] For more information, see http://www.ieso.ca/Documents/consult/ME/ME-20160419-Market-Design-Considerations.pdf at slide 2.

are contributing to instances where less OR is scheduled than the OR requirement, the Panel believes that the IESO should place a high priority on developing solutions to mitigate the impact of forecast errors on the energy and OR market. The Panel will actively monitor this engagement.

3 Negative HOEPs

Typically, negative energy prices signal an abundance of supply relative to demand. There are many events that contribute to the occurrence of negative HOEPs such as low Ontario demand, failed export transactions or an abundance of supply offered at negative prices. Generators ordinarily offer energy at negative prices either to avoid getting dispatched off where such an event would be economically undesirable, or to ensure their participation in the market where contracted rates have desensitized them from variations in the market price.

During the Current Reporting Period there were 371 negative HOEPs. Due to the large numbers of negative HOEPs because of consistent surplus baseload generation (SBG), the Panel will not report on the causes of negative HOEPs in individual hours. SBG hours have increased in line with expectations given the changes in Ontario's underlying supply mix and relatively stable demand.

4 Anomalous CMSC Payments

An anomalous hourly CMSC event is defined as an hour where total CMSC payments exceeded $500,000. An anomalous daily CMSC event is defined as a day where the total CMSC payments exceeded $1,000,000. There were no such days in the Current Reporting Period.

5 Anomalous IOG Payments

An anomalous IOG event is defined as either a day where the total payments made through the IOG program exceeded $1,000,000 or an hour where the total payments made through the IOG program exceeded $500,000.

Neither of these thresholds was met during the Current Reporting Period.

6 Five Highest Daily DA-PCG Payment Totals

Day Ahead-Production Cost Guarantee (DA-PCG) payments are made to ensure that generators scheduled through the Day-Ahead Commitment Process (DACP) are guaranteed to recover certain eligible day-ahead costs. These costs are:

- Speed – No Load Costs
- Start-Up Costs
- Incremental Energy Costs

Table 2-8 below shows the top five highest DA-PCG payments made to generators during the Current Reporting Period.

Table 2-8: Anomalous DA-PCG Payments (daily)
Five Highest Daily DA-PCG Payments
May – October 2015
($)

Delivery Date	Facility Name	PCG Payment
17/08/2015	Facility A	158,868
29/07/2015	Facility A	148,856
16/09/2015	Facility A	141,754
17/09/2015	Facility A	130,797
18/10/2015	Facility B	116,429

7 High RT-GCG Payments

The Generator Cost Guarantee (RT-GCG) program ensures that eligible generators who are scheduled in real time are guaranteed to recover certain eligible costs relating to start-up and the facilities Minimum Generation Block Run Time (MGBRT) and Minimum Loading Point (MLP). The top five RT-GCG runs with the highest RT-GCG payments during the Current Reporting Period are shown in Table 2-9 below with their corresponding dates.

Table 2-9: Highest RT-GCG Payments
May – October 2015
($)

Date	Facility Name	Payment
06/09/2015	Facility C	9,520,769
06/09/2015	Facility C	1,835,499
06/09/2015	Facility C	1,834,541
04/10/2015	Facility D	299,750
04/10/2015	Facility D	273,755

The combined payments of over $13 million to Facility C on September 6, 2015 are associated with a cost submission for maintenance costs incurred over multiple starts in the previous several years. The IESO has stated that it will be auditing the payment against revenues earned over those historical starts.

Chapter 3: Matters to Report in the Ontario Electricity Marketplace

1 Introduction

In this chapter, the Panel presents its analysis of two aspects of the IESO-administered markets. The Panel's analysis considers the inefficiency on Ontario's interties induced by the two-schedule system, as well as several issues relating to the IESO's Real-time Generation Cost Guarantee program.

2 Panel Investigations

The Panel may conduct an investigation into the conduct of market participants, including in relation to inappropriate or anomalous market conduct, when it considers such an investigation is warranted. The Panel currently has one gaming investigation under way in relation to a generator.

3 New Matters

3.1 Inefficiency on Ontario's Interties Induced by the Two-Schedule System

In past Monitoring Reports the Panel has commented on the efficiency of electricity flows on the interties that connect Ontario to neighbouring jurisdictions.[79] The Panel found that, among other issues, the two-schedule price setting system (two-schedule system) has had a considerable impact on incenting inefficiency on the interties. In its August 2007 Monitoring Report the Panel estimated this inefficiency to be $50 million per year on the New York intertie alone.[80] With the IESO currently considering the merits of alternate market design options as part of its Market Renewal stakeholder engagement,[81] including the potential adoption of locational marginal pricing, the Panel revisits the issue of inefficiency on Ontario's interties to help inform the engagement. Specifically, the Panel has reviewed recent market outcomes in order to demonstrate how the current two-schedule system contributes to inefficiency on Ontario's interties.

[79] For references to past Panel commentary on the issue see the section below entitled "History of Panel Commentary regarding Inefficiency on the Interties".
[80] *Ibid.*
[81] For more information see the IESO's Market Renewal stakeholder engagement webpage, available at: http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/Market-Renewal.aspx

3.1.1 Defining Efficiency on the Interties and the Wedge Created by the Two-Schedule System

Electricity trade between jurisdictions increases productive efficiency when electricity flows from a lower cost jurisdiction to a higher cost jurisdiction, allowing for electricity demand to be met at a lower total cost.[82] Trade from the lower cost jurisdiction to the higher cost jurisdiction increases productive efficiency until the costs equalize across jurisdictions. At this point total production costs have been minimized, gains from trade have been fully exploited and any divergence from this outcome would only increase total production costs.

Productive efficiency is dependent on the marginal cost of supplying electricity, which is not necessarily the same as the price at which electricity is sold. The distinction between price and cost is particularly important in the context of the Ontario wholesale electricity market due to the two-schedule system. The two-schedule system, and the accompanying uniform price regime, separates the price at which electricity is bought and sold from the cost of supplying it.

The two schedules of Ontario's two-schedule system refer to the "unconstrained sequence" and the "constrained sequence". The determination of price and cost are split between these two sequences, with the price determined in the unconstrained sequence and the cost determined in the constrained sequence. The divergence of price and cost is the result of differing assumptions amongst the unconstrained and constrained sequences.

For the purpose of achieving a uniform "market clearing price" for the entire province, the unconstrained sequence optimizes supply and demand whilst ignoring many of the operational constraints of the transmission grid and individual facilities.[83] Conversely, the constrained sequence optimizes supply and demand bound by those same operational constraints, producing the lowest cost solution which can be accommodated by the configuration of the electricity grid. Outputs of the constrained sequence include the production and consumption schedules to be

[82] In this context, the term "cost" refers to the change in total system costs associated with serving the next megawatt of non-dispatchable demand. When there is no transmission congestion this cost is notionally equal to the marginal cost of the supplying resource (typically a generator) plus the cost of transmission losses. In the presence of transmission congestion, this cost is notionally equal to the change in total system costs associated with dispatching resources to respect the transmission constraint while meeting the incremental demand. The dispatch solution could involve increasing the schedule of some resources, while decreasing the schedule of others, plus the cost of transmission losses.

[83] For instance, the unconstrained sequence ignores transmission constraints within Ontario. Additionally, it treats dispatchable generators and loads as if they can change production or consumption at their facilities three times faster than they are capable of.

followed by each resource, as well as measures of the cost of satisfying additional demand at each location on the grid. Put simply, the constrained sequence provides the most realistic representation of the conditions on the power system, the unconstrained sequence does not.

When the price of electricity (determined in the unconstrained sequence) is the same as the cost (determined in the constrained sequence), profit seeking behaviour induces efficient outcomes; what is privately profitable is also productively efficient. When price and cost diverge, as they often do in Ontario, what is privately profitable may not be productively efficient, and vice versa. Intertie traders are motivated by private incentives not social efficiencies; when these two things diverge, inefficiency is bound to occur.

3.1.2 How the Wedge Created by the Two-Schedule System Induces Inefficiency on the Interties

In the context of electricity trading, the wedge between price and cost can lead to inefficiency by either incenting too much, or too little trade in a given direction. For ease and consistency of reference the following analysis will consider trade from an Ontario net export perspective. The optimal (i.e. efficient) quantity of net exports occurs where total production costs are minimized: the point at which the costs equalize across jurisdictions. If the net export quantity is not optimal, say if efficiency could be improved by decreasing net exports, there are "excessive net exports". Alternatively, if efficiency could be improved by increasing net exports, there are "insufficient net exports".[84]

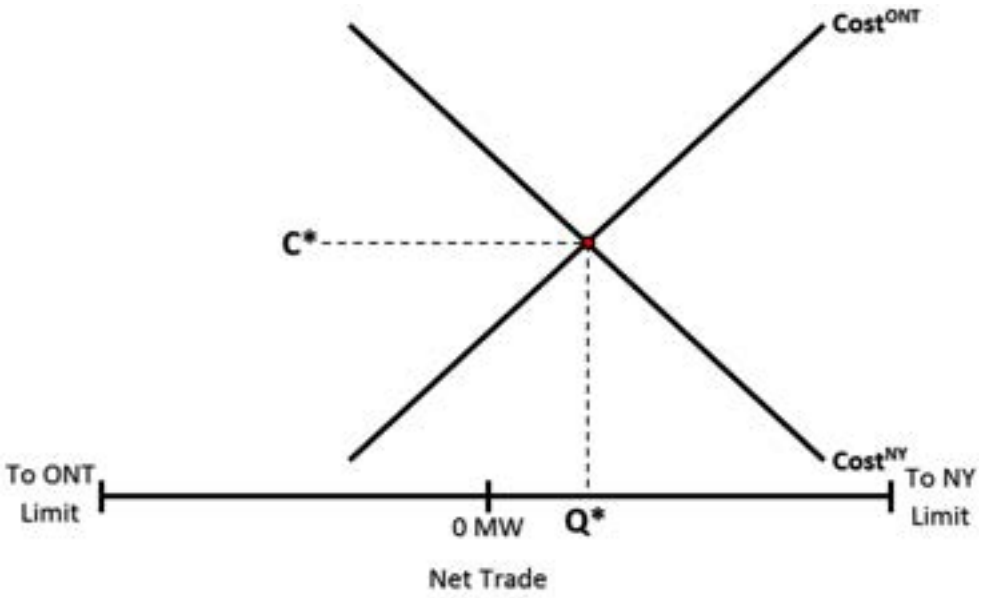
Consider the following simplified example of trade between Ontario and New York (illustrated in Figure 3-1). The optimal net export quantity (Q*) is the quantity corresponding to the intersection of the cost curves for New York and Ontario ($Cost^{ONT}$ and $Cost^{NY}$), at which quantity the cost in Ontario and New York are equal (C*).[85] The New York cost curve is inverted

[84] Note that negative net exports are positive net imports. It follows that "excessive net exports" is equivalent to "insufficient net imports", and vice versa.

[85] These simplified cost curves represent the residual supply curves at either side of the intertie. The supply curves are affected by the physical limitations of the grid (for example, supply offered in the Northwest is unlikely to factor heavily into the supply curves in southern Ontario) as well as domestic demand.

to capture the cost trade-off between jurisdictions as net exports change.[86] Alternatively this curve could be thought of as the demand for Ontario electricity in New York.

Figure 3-1: Example of Trade between Ontario and New York



The intersection of the two cost curves determines the optimal net export quantity (Q*). If there is no wedge between price and cost, as is the case in this example, one would expect the actual net export quantity to approximately equal the optimal net export quantity.[87] In jurisdictions that employ some form of locational marginal pricing, such as New York, price and cost are equal, at least in terms of eliminating the wedge created by Ontario's two-schedule system.[88] As such, in our example the New York cost curve also represents the New York price curve. In Ontario, the two-schedule system creates a wedge between price and cost, and is thus represented as two separate curves in the examples to follow.

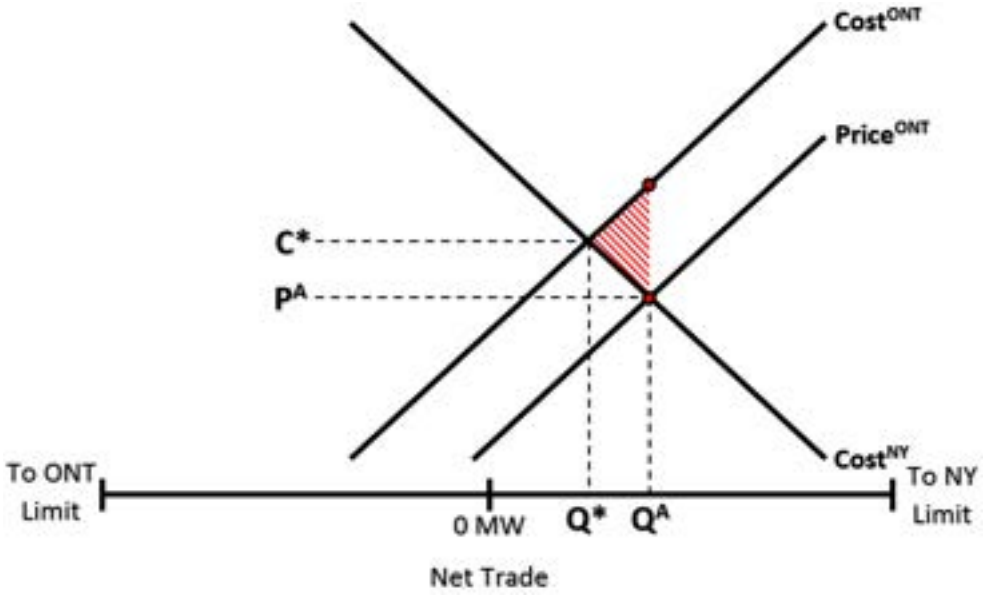
[86] For example, starting at the optimal net export quantity (Q*), increasing net exports to New York by 1 MW increases total production in Ontario by 1 MW (a move up the Ontario cost curve, $Cost^{ONT}$) and decreases production in New York by 1 MW (a move down the inverted New York cost curve, $Cost^{NY}$).

[87] For illustrative purposes, Figure 3-1 represents a simplified model of electricity trading between jurisdictions. This simplified example assumes perfect competition and information, among other assumptions that do not necessarily hold in reality. As discussed later in the chapter, even absent a wedge between price and cost, seams issues can contribute to a divergence between the actual net export quantity and the optimal net export quantity.

[88] New York employs a hybrid locational marginal pricing system whereby generators and intertie traders are settled based on locational marginal prices at individual nodes, while loads are settled based on zonal prices. Zonal prices are calculated as the load weighted average price of all nodes within a zone. Under such a system, a wedge can exist between the price charged to domestic loads and the cost of supplying that electricity; such a wedge does not exist for generators and intertie traders.

Consider the example illustrated in Figure 3-2, when the price of electricity in Ontario is lower than the cost.[89] This lower price is represented by a rightward shift of the Ontario price curve ($Price^{ONT}$) relative to the Ontario cost curve. Theoretically, intertie traders, who buy and sell at the price of electricity, will arbitrage price differences between Ontario and New York until the prices are equal (P^A) and no further arbitrage opportunities exist. Given that the Ontario price is less than the Ontario cost at all net export quantities, the actual quantity of net exports (Q^A) will exceed the optimal quantity of net exports (Q*). The difference in quantity between the two outcomes is referred to as the excessive net export quantity. In effect, the lower price has induced excess demand for Ontario electricity.

Figure 3-2: Example of Excessive Net Exports to New York



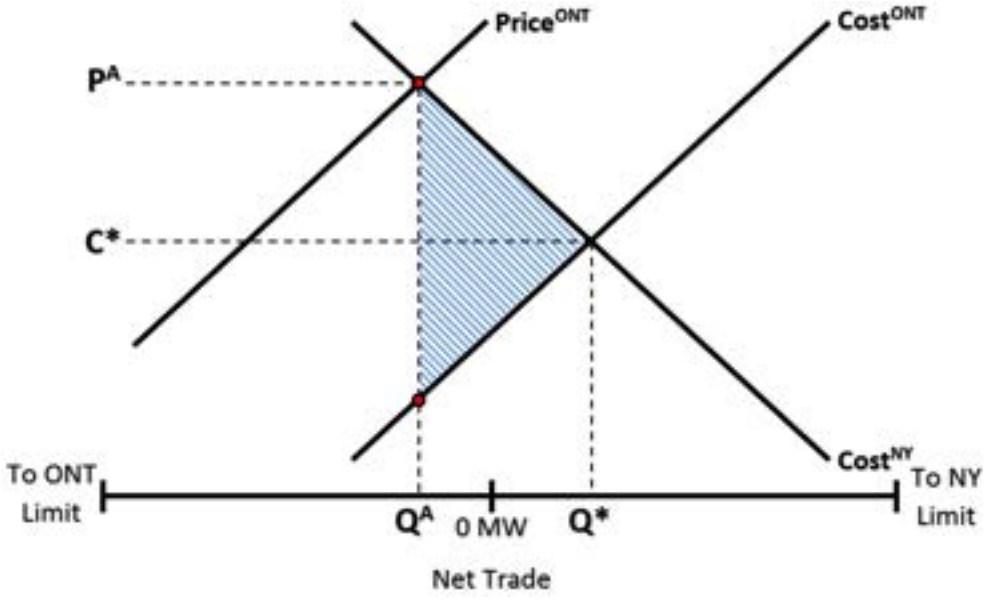
Given the actual net export quantity (Q^A), the efficiency loss associated with excessive net exports to New York is measured by the degree to which higher-cost Ontario supply replaced lower-cost New York supply (equal to the area of the red triangle). That is to say, for each megawatt of net exports between Q* and Q^A, the cost of producing electricity in Ontario and exporting it to New York was higher than the cost of producing the electricity in New York.

[89] As noted earlier, this could be the result of a number of things, including the unconstrained sequence ignoring internal transmission constraints, and/or the treatment of generators as if they can ramp three times faster than they are capable of.

However, due to the wedge between price and cost, these inefficient transactions were profitable for intertie traders and were thus consummated (there were excessive net exports).

The opposite case is that of insufficient net exports. Consider the example illustrated in Figure 3-3, where the price of electricity in Ontario is higher than the cost. Given cost curves identical to those in Figures 3-1 and 3-2, the optimal net export quantity (Q*) is positive (Ontario exports to New York on a net basis). As the Ontario price curve is to the left of the Ontario cost curve, the Ontario price is greater than the Ontario cost at all net export quantities. The fact that the price is higher than the cost in Ontario will result in fewer net exports (Q^A) relative to the optimal net export quantity (Q*). The difference in quantity between the two outcomes is referred to as the insufficient net export quantity. In effect, the higher price has induced insufficient demand for Ontario electricity.

Figure 3-3: Example of Insufficient Net Exports to New York



Given the actual net export quantity (Q^A), the efficiency loss associated with insufficient net exports to New York is equal to the degree to which higher-cost New York supply *could have been* replaced with lower-cost Ontario supply *but was not* (equal to the area of the blue triangle). That is to say, for each megawatt of net exports between Q^A and Q*, the cost of producing electricity in Ontario and exporting it to New York was lower than the cost of producing the electricity in New York. However, due to the wedge between price and cost, these efficient

transactions were unprofitable for intertie traders and thus went unconsummated (there were insufficient net exports).

The example above illustrates an important concept, while the cost curves may be such that the optimal net trade quantity be in one direction (in this case the export direction), the position of the price curves may result in actual net trade in the opposite direction (imports in this case).

From an efficiency standpoint, the inefficiency associated with insufficient net exports (Figure 3-3) is just as undesirable as the inefficiency associated with excessive net exports (Figure 3-2), as both have the effect of increasing total production costs.

3.1.3 History of Panel Commentary Regarding Inefficiency on the Interties

The Panel discussed inefficiency on Ontario's interties in three successive semi-annual monitoring reports from June 2006 to August 2007.

In its June 2006 Monitoring Report the Panel reported on inefficiency on the Ontario to New York intertie, observing that excessive net exports occurred in approximately 25% to 30% of all hours over a two-year period. The report included a theoretical example which demonstrated how the two-schedule system can create a wedge between price and cost and incent excessive net exports to New York. The Panel concluded its analysis by noting that the two-schedule system also leads to domestic inefficiency, and that the adoption of locational marginal pricing would reduce these inefficiencies.[90]

In its December 2006 Monitoring Report the Panel examined the factors that influence the size of the wedge between price and cost. The Panel noted that the average wedge had been decreasing over time, resulting in a reduction in the frequency of excessive net exports to New York. However, it determined that this was related to other changes in the market rather than as a result of an improvement to the two-schedule system market design. Again, the Panel concluded

[90] For more information see pages 68-79 of the Panel's June 2006 Monitoring Report, available at: http://www.ontarioenergyboard.ca/documents/msp/msp_report_final_130606.pdf

its analysis by noting that the solution to this problem was to adopt some form of locational marginal pricing.[91]

Having established that the wedge between price and cost had led to inefficiency on the interties, and examined the sources of the wedge, the Panel estimated the efficiency gains that could be realised if exports to New York were charged the marginal cost of production (as calculated in the constrained sequence) and not the price (as calculated in the unconstrained sequence) in its August 2007 Monitoring Report. Using historic costs and estimates of export elasticity the Panel estimated that this change would have resulted in efficiency gains of approximately $50 million in 2006 alone. While recognizing the limitations of its study, the Panel felt the results were directionally correct and provided sufficient evidence for it to recommend that the IESO assess the efficiency benefits and costs of moving to a locational marginal pricing market design.[92]

3.1.4 Inefficiency on the Interties Induced by the Two-Schedule System

In the sections that follow the Panel examines recent market outcomes and concludes that the current two-schedule system continues to contribute to inefficiency on Ontario's interties. The analysis focusses on the New York intertie, though the Panel found similar results at other Ontario interties.[93]

Variables used to Identify Inefficiency on the Interties

In order to consider how the two-schedule system has contributed to inefficiency on the interties, reasonable measures of cost and price are needed for both sides of each transaction. The Panel chose the following variables as measures for cost and price in the importing and exporting jurisdictions:

[91] For more information see pages 104-110 of the Panel's December 2006 Monitoring Report, available at: http://www.ontarioenergyboard.ca/documents/msp/msp_report_final_20061222.pdf

[92] For more information see pages 145-153 of the Panel's August 2007 Monitoring Report, available at: http://www.ontarioenergyboard.ca/documents/msp/msp_report_20070810.pdf

[93] As part of its analysis the Panel also examined the interties connecting Ontario with Michigan, Minnesota and the Pennsylvania-Jersey-Maryland Interconnection in the manner in which the New York intertie was examined. The Panel found similar results across all interties. The Panel did not examine the Manitoba and Québec interties as these jurisdictions do not have wholesale electricity markets, and therefore do not have explicit and public measures of price and cost, this makes it difficult to observe inefficiency.

Ontario, Price – the real-time unconstrained zonal price in the respective intertie zone in Ontario. This price is what intertie traders pay in Ontario when exporting, or are paid when importing.

Ontario, Cost – the average hourly real-time constrained nodal price at the generator located nearest the relevant intertie.[94]

External Jurisdiction, Price and Cost – all interties examined in this study connect to jurisdictions with wholesale electricity markets that employ some form of locational marginal pricing. Under these pricing systems, price and cost are equal, at least in terms of eliminating the wedge created by Ontario's two-schedule system. The locational marginal price is the price intertie traders pay in the external jurisdiction when exporting from that market to Ontario, or are paid when importing to that market from Ontario.

Actual Net Exports – net exports in Ontario's real-time constrained sequence.

Instances of Inefficiency on the Interties

To start, the Panel reviewed recent market outcomes at the New York intertie to identify hours in which inefficiency occurred. Figure 3-4 plots net exports and the cost spread between New York and Ontario over a two-year period. The cost spread, plotted against the Y-axis, is positive when New York's cost is higher than that of Ontario and negative when the reverse is true. Recall that gains from trade are maximized at the optimal net export quantity, where the costs between jurisdictions are equal.[95]

- Hours with optimal net exports (yellow dots) are identified by instances where the costs between jurisdictions are approximately equal.[96]

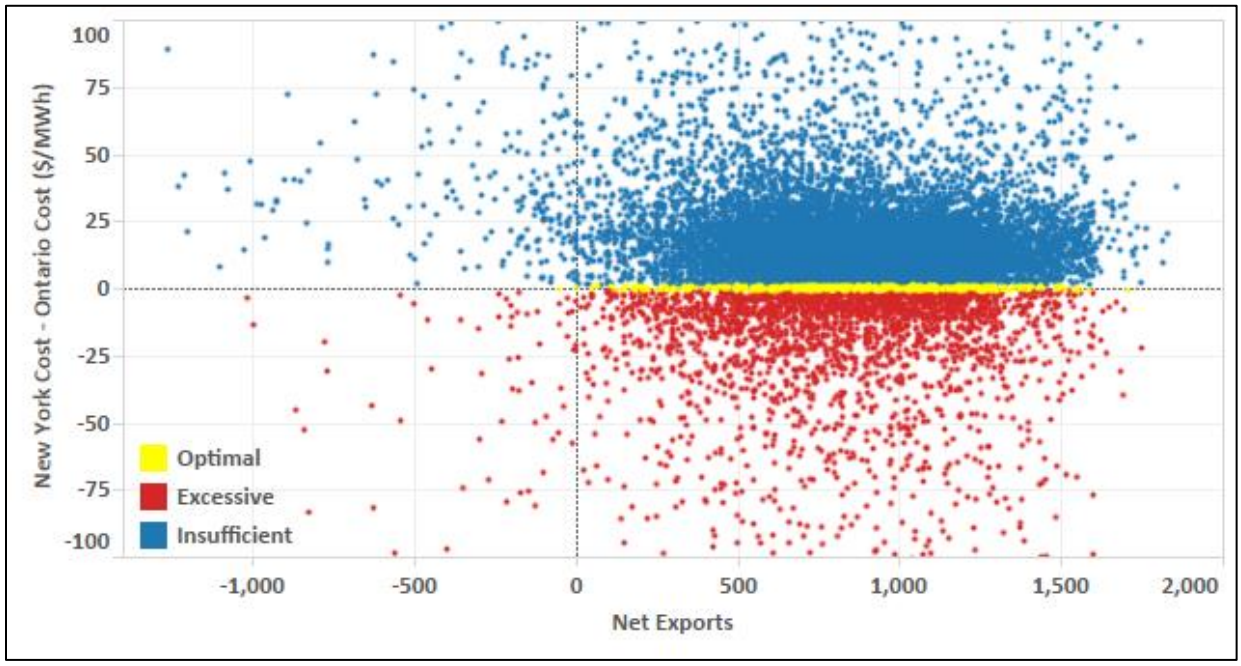
[94] There is no real-time nodal price at the intertie itself. Consequently, the Panel believes that the real-time nodal price of the nearest generator provides the best representation of the real-time marginal cost of supplying the next megawatt of non-dispatchable demand at the intertie. The real-time price at the nearest generator does not include the cost of congestion at the intertie itself. Accordingly, hours with intertie congestion in pre-dispatch (the best indicator of whether there would be intertie congestion in real-time) have been removed from the analysis that follows so as to avoid misrepresenting the cost during those hours.

[95] Per the previous footnote, hours in which trade in the efficient direction was limited by the intertie capacity (as represented by congestion in pre-dispatch) have been removed from Figure 3-4 and subsequent figures; this occurred in approximately 21% of all hours. Net export flows during these hours are optimal given the limited capacity of the intertie. This also suggests that efficiency could be improved during those hours if the intertie capacity was increased.

[96] Because supply curves are non-linear and step-like, one would not expect a cost difference of exactly $0/MWh between jurisdictions, even when price and cost are equal.

- Hours with excessive net exports (red dots) are identified by instances where the Ontario cost is higher than that of New York (bottom half).[97]
- Hours with insufficient net exports (blue dots) are identified by instances where the New York cost is higher than that of Ontario (top half).

Figure 3-4: Net Exports and the New York – Ontario Cost Spread
May 2013 – April 2015
(MW & $/MWh)



In the vast majority of hours, the actual net export quantity on the New York intertie did not equal the optimal net export quantity, as evidenced by the number of hours with excessive or insufficient net exports (red and blue dots).

While the actual net export quantity was not optimal in most hours, only limited conclusions can be drawn about the magnitude of inefficiency in any given hour. This limitation arises due to the fact that, despite being able to observe the actual net export quantity (Q^A from Figures 3-2 and 3-

[97] Note that "excessive net exports" does not necessarily mean that Ontario was a net exporter (see the red dots in the lower-left quadrant), it means there should have been fewer net exports (i.e. greater net imports). The same logic applies for "insufficient net exports".

3), the optimal outcome (Q*) did not occur and thus cannot be observed. As a result the quantity of the excessive or insufficient net exports is unknown.[98]

What can be said is that, all else being equal, the larger the spread between the cost in Ontario and the cost in New York, the larger the difference between the actual net export quantity and the optimal net export quantity, and thus the greater the inefficiency. While all else is not equal from hour to hour in reality, this relationship likely holds across a large sample of hours.

While it is unsurprising that the combination of profit-seeking behaviour by intertie traders and Ontario's two-schedule system did not lead to cost convergence between jurisdictions very often, did their trading behaviour lead to price convergence?

Over the two-year period the price spread between Ontario and New York was much narrower than the cost spread. The average absolute **price spread** per hour was $20/MWh with a standard deviation of $44/MWh, while the average absolute **cost spread** per hour was $28/MWh with a standard deviation of $85/MWh. This data supports the idea that electricity trade is driven by the price spread between jurisdictions, and not the cost spread; intertie traders are motivated by private incentives not social efficiencies.

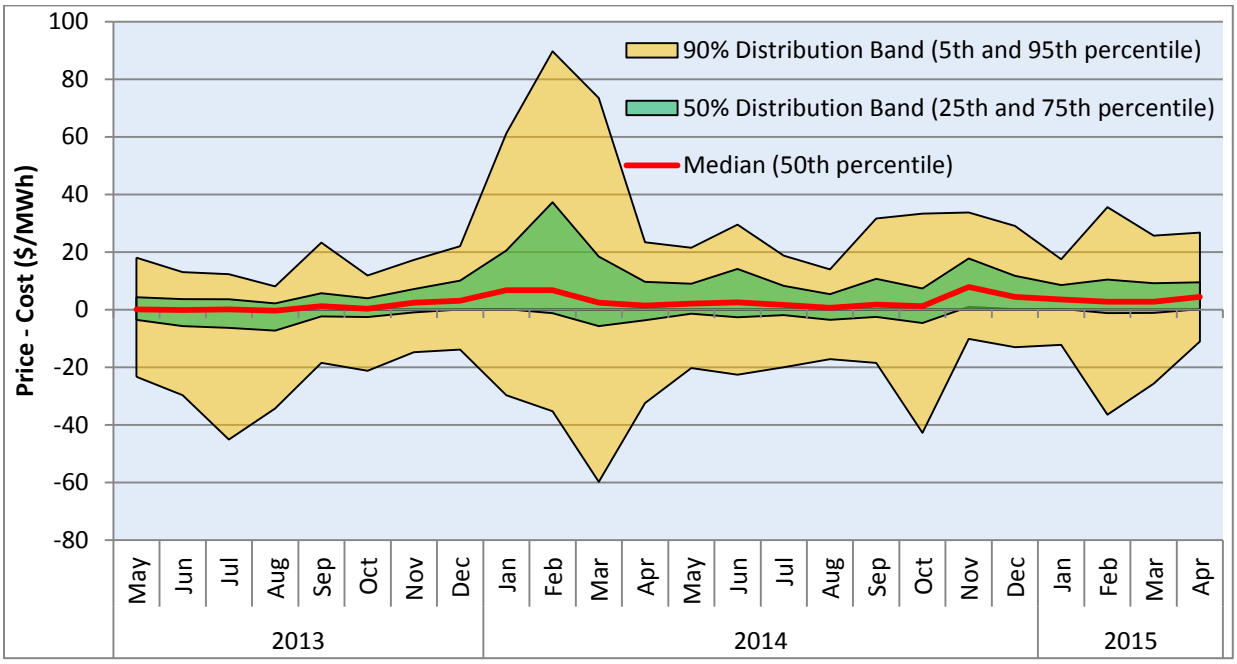
Frequency of a Wedge between Price and Cost in Ontario

Having observed that inefficiency on the interties does occur, the Panel considered whether the two-schedule system and the wedge between price and cost could be driving these outcomes.

The larger and the more frequent the wedge between the price of electricity in Ontario and the cost, the greater the likelihood of inefficiency on the intertie. Figure 3-5 displays the monthly distribution of the hourly difference between price and cost in Ontario at the New York intertie. For example, in the first month of the series (May 2013), the price in Ontario was within +/- $20/MWh of the cost in Ontario during 90% of hours. The wider the spread of the distribution band, the more significant the wedge between price and cost during that month and thus the greater the likelihood of inducing inefficiency on the intertie.

[98] It is possible to estimate what the optimal net export quantity would have been, however doing so accurately is challenging. Accurate estimation would require a simulator with detailed constrained models of both jurisdictions, something the Panel does not have access to, as well as detailed information on the supply and demand curves prevailing in each jurisdiction at the time.

Figure 3-5: Wedge between Price and Cost in Ontario at the New York Intertie
May 2013 – April 2015
($/MWh)



Significant divergences between price and cost occurred regularly over the two-year period. The price in Ontario was higher than the cost in 65% of hours, often by a significant margin. For instance, in November 2014 the price was higher than the cost in 80% of hours, with the average difference exceeding $14/MWh during those hours.

Differences between price and cost were positively correlated with the price: during months when average price was relatively high, the distribution of the difference between price and cost was wider. For example, the monthly average price during February 2014 was the highest of the period ($78/MWh), the distribution of the difference between price and cost was also the widest during this month (90% of hours had a difference between -$35/MWh and $90/MWh).

Identifying Inefficiency on the Interties Induced by the Two-Schedule System

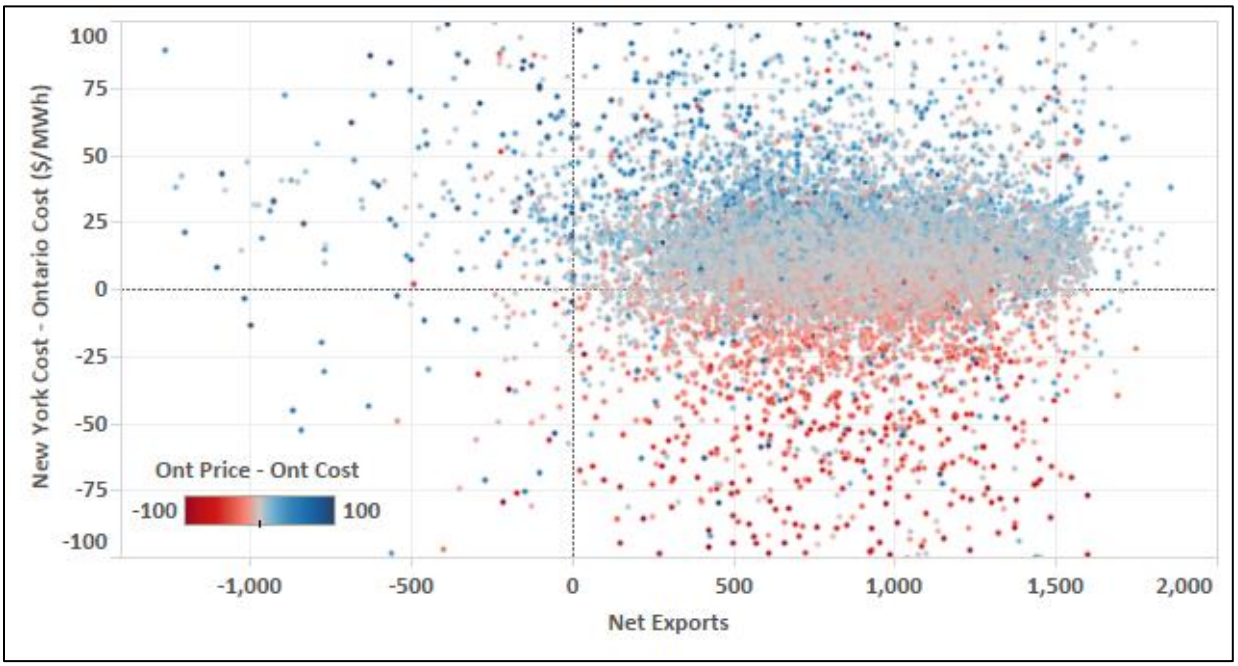
While the Panel has identified 1) many hours with insufficient or excessive net exports (see Figure 3-4), and 2) a frequent wedge between price and cost in Ontario (see Figure 3-5), inefficiency on the interties occurs in all electricity markets to some degree, even those with locational marginal pricing systems. Issues that cause insufficient or excessive electricity trade in

all electricity markets include: offer and bid timing, intertie schedule timing, transaction charges and reliability curtailments, among other issues.[99]

Figure 3-6 integrates the information of Figures 3-4 and 3-5 to help demonstrate how the two-schedule system contributed to inefficiency on the intertie. Specifically, Figure 3-6 plots net exports and the cost spread between New York and Ontario over a two-year period, just as was done in Figure 3-4. Recall from Figure 3-4 that hours when the New York cost was higher than that of Ontario (upper half) there were insufficient net exports, while when the Ontario cost was higher than that of New York (lower half) there were excessive net exports. In addition to this information the hourly difference between price and cost in Ontario from Figure 3-5 has been incorporated into the data points using a colour scale. The blue dots indicate hours when the price in Ontario exceeded the cost, while the red dots indicate hours when the opposite is true. The larger the difference between price and cost the darker the colour, with hours when price and cost are approximately equal appearing as grey dots.

[99] These issues are often referred to as "seams issues" when discussing intertie transactions. The IESO is already exploring more frequent intertie scheduling in order to mitigate schedule timing induced inefficiency. In its stakeholder engagement "Review of Ontario Interties", the IESO indicated that it will include more frequent intertie scheduling in its broader market development plan to improve the efficiency and the effectiveness of Ontario's wholesale electricity market.

Figure 3-6: Net Exports, New York-Ontario Cost Spread and Ontario Cost-Price Spread
May 2013 – April 2015
(MW & $/MWh)



While the above analysis may not allow definitive conclusions to be drawn about the source of inefficiency in any one specific hour,[100] the patterns that emerge over the larger sample of hours allow us to infer several key findings:

- In hours when the price in Ontario was less than the cost (red dots), it was more frequently observed that the Ontario cost was higher than the New York cost (lower half). **In other words, when Ontario sold electricity below cost, there were excessive net exports.**
- Conversely, in hours when the price in Ontario was higher than the cost (blue dots), it was more frequently observed that the New York cost was higher than the Ontario cost (upper half). **In other words, when Ontario sold electricity above cost, there were insufficient net exports.**

[100] To determine with certainty the source of inefficiency in a given hour, one would need to carefully consider all market conditions at the time of the transactions, as well as leading up to it. The unavailability of certain data, such as pre-dispatch prices in neighbouring jurisdictions, precludes such analysis.

- When the price and cost in Ontario were approximately equal (grey dots), convergence between the cost in Ontario and the cost in New York was observed (the closer to the x-axis). **In other words, when Ontario sold electricity at cost, efficiency was approximately maximized.**[101]
- The larger the difference between the price in Ontario and the cost (dark red and dark blue dots), the larger the cost spread between Ontario and New York (the further from the x-axis). **In other words, the larger the wedge between the price of electricity in Ontario and the cost, the greater the inefficiency.**

All of these findings support the view that the wedge between the price and the cost in Ontario created by the two-schedule system incents inefficiency on the New York intertie. The persistent and significant spread between the cost in Ontario and the cost in New York strongly suggests that actual net export quantities are often far from optimal net export quantities, and that the inefficiency associated with insufficient and excessive trade is large. These findings are consistent with the Panel's August 2007 findings regarding inefficiency on the New York intertie: charging intertie traders the cost of electricity (as opposed to the prevailing price) would have resulted in efficiency gains of approximately $50 million in 2006 alone.[102]

3.1.5 Conclusions

The Panel's analysis suggests that there continues to be significant inefficiencies associated with electricity trade between Ontario and its neighbouring jurisdictions. Some causes of inefficiency affect all electricity markets, such as schedule timing and transaction charges, while other causes of inefficiency affect only Ontario, such as the two-schedule system. This source of inefficiency is significant, and can be eliminated if a locational marginal pricing market design were adopted. The IESO has launched a stakeholder engagement that will consider fundamental market design

[101] When the price and cost in Ontario align (grey dots), and Ontario is a net exporter (right half), cost convergence at a $0/MWh spread was not frequently observed, but instead a persistent spread where the New York cost is higher than the Ontario cost by $10/MWh to $15/MWh (i.e. there are insufficient net exports). This persistent spread is likely the result of transaction charges, specifically uplift and the export tariff in Ontario. Neither uplift nor the export tariff are captured in the measure of price used in this section, but both increase the price of buying Ontario electricity, but not the cost. Similar to the wedge between price and cost created by the two-schedule system, transaction charges levied on exporters can lead to insufficient net exports.
[102] For more information on the Panel's August 2007 study, see section 3.1.2 History of Panel Commentary regarding Inefficiency on the Interties.

issues and changes, which may include consideration of a locational marginal pricing system.[103] The Panel strongly encourages the IESO to continue work towards implementing such a pricing system.

3.2 A Review of the IESO's Real-Time Cost Guarantee Program

3.2.1 Introduction

In the course of the Panel's regular monitoring of the IESO-administered markets, few topics have appeared more often in its bi-annual monitoring reports than the IESO's real-time generation cost guarantee (RT-GCG) program. The program has been a fixture in Ontario's wholesale electricity market since 2003, shortly after market opening. While the program has evolved over the years, the Panel continues to find reasons to be concerned with it.

The Panel has previously commented on the RT-GCG program, highlighting and recommending changes to specific aspects. In this report, the Panel provides a more comprehensive summary of its concerns with the cost of the program and makes two recommendations to address those concerns.

At the most fundamental level, the Panel questions the extent to which the RT-GCG program is truly necessary to serve a reliability purpose. The Panel's analysis found that, in 2014, commitments through the RT-GCG program were needed to meet real-time domestic demand and operating reserve requirements in less than 1% of the hours in which a commitment actually occurred. These needs were met at a cost of $61 million. The IESO has not provided any analysis of the continued need for the program, although the Panel has recommended on more than one occasion that such an analysis be done.

The Panel acknowledges that the IESO has to manage changing conditions between day-ahead and real-time. The Panel also acknowledges that the IESO is considering a longer-term solution in the form of an enhanced intra-day unit commitment program. However, by the IESO's own admission that solution is many years away and it is unclear to the Panel why changes to the program that have the potential to save millions in costs should not be made now. The Panel

[103] For more information see the IESO's Market Renewal stakeholder engagement webpage, available at: http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/Market-Renewal.aspx

believes that the RT-GCG program pays generators in excess of what is required to achieve the program's objective of incenting generators to come online in real-time in support of reliability. These unnecessary payments total approximately $40 million per year; the cost of which are ultimately borne by Ontario ratepayers.

The Panel does not believe that there is a demonstrable need for the RT-GCG program to guarantee start-up operations and maintenance (O&M) costs. Since 2010, the RT-GCG program has paid out $280 million for such costs. The Panel finds it instructive that the program served its intended function for over six years and more than 6,000 unit commitments without guaranteeing O&M cost recovery. Accordingly, the Panel is not convinced that the current guarantee (and associated payouts) of O&M costs has provided Ontarians with commensurate value in terms of an incremental reliability benefit. The Panel recommends that the IESO eliminate the guarantee of start-up O&M costs from the RT-GCG program, a change which is expected to reduce the cost of the program by approximately $30 million annually.

The RT-GCG program also allows resources to operate profitably, on an all in basis, and still receive a guarantee payment. The Panel does not consider this a reasonable outcome. Accordingly, the Panel recommends that the revenues used to offset the guaranteed costs be expanded to include all net energy and operating reserve as well as all CMSC revenues received while the unit is online. The Panel has calculated that implementing such a change will further reduce the cost of the program by approximately $10 million per year while reducing the incentive for generators to inefficiently schedule their guarantee hours.

3.2.2 History of Guarantee Programs

Electricity is a product that most consumers expect to be delivered immediately and at any quantity demanded. The IESO takes the necessary steps to procure and deliver the required amount of electricity at every second of every day. It uses programs like the RT-GCG in order to incent domestic generators to offer their supply to the market in real-time to meet demand. This section provides a brief history of the IESO's activities in this regard, specifically, the types of costs that the IESO has guaranteed throughout the years, with an emphasis on the evolution of the RT-GCG program.

In September 2003 the IESO introduced the RT-GCG, then named the spare generation online (SGOL) program. Material posted on the IESO's Technical Panel (TP) webpage articulated the need for the program which was to reduce the need for the IESO to take out-of-market control actions in response to real-time changes in market and system conditions.[104]

The 2003 SGOL program provided a guarantee for fuel costs. Generators would submit their fuel costs several days after the day of operation, what the Panels refers to as 'after-the-fact' submissions, and if their energy market revenues were not sufficient to cover those fuel costs, the IESO would make a payment for the difference.

The TP material that described the RT-GCG program explicitly excluded other incremental costs from the guarantee and such costs remained out of the RT-GCG's scope until 2009. According to the IESO's TP material, O&M costs were not included in the 2003 RT-GCG for three reasons:

- Limit the advantage that the cost guarantee would provide non-quick start facilities over quick-start facilities;
- Simplify for participants the determination of applicable guaranteed costs; and
- Reduce the need for the IESO to audit the RT-GCG.[105]

The TP meeting minutes at the time of SGOL rule amendment show that there was discussion amongst the TP members that more than just fuel costs should be included as part of the guarantee. However, a counter argument was made that guarantee of too many costs would risk losing the support of the loads on the TP and the guaranteed costs remained restricted to fuel only.[106]

[104] "It is expected this initiative will reduce the frequency of the need for the IMO to use out of market control actions in response to market and system changes in real-time."

Expected benefits of the program were listed as, "[the SGOL is] expected to assist in the maintenance of the reliable operation of the IMO controlled grid, through the additional resources being available to address reliability concerns as well through improved and rational pricing signals and outcomes at times of market need." For more information on the IESO's rationale for implementing the SGOL program, see the IESO's Market Rule Amendment Proposal, available at: http://www.ieso.ca/Documents/Amend/mr/mr_00235-R00-R05.pdf

[105] For more information on the IESO rationale for guaranteeing only fuel costs in the SGOL program, see the IESO Board's Decision, page 20, available at: http://www.ieso.ca/Documents/Amend/mr/mr_00235-R00-R05_BA.pdf

[106] For more information on discussion from the TP meeting, see the final meeting minutes, available at: http://www.ieso.ca/Documents/tp/tp_min_2003Jun24.pdf

In the summer of 2005 Ontario experienced tight supply conditions, with demand at times exceeding Ontario's own generation capacity. As a result, the IESO relied on imports to service domestic demand and, at times, was forced to take emergency control actions to support reliability.

In September 2005 the IESO began a stakeholder engagement (SE) to create a day-ahead commitment process (DACP) that would provide a day-ahead intertie offer guarantee for importers as well as a day-ahead cost guarantee (DA-GCG) for domestic generators. An IESO presentation highlighted the difficult conditions in the summer of 2005 and explained the factors that contributed to the need for emergency control actions; such factors included the failure of import transactions.[107] According to the IESO, import failures were precipitated by the lack of a financially firm day-ahead import offer guarantee.[108] Lack of availability/reliability from non-quick start domestic generation was not listed as a factor contributing to the need for emergency actions.

Throughout the stakeholder sessions, the IESO proposed that the DA-GCG would include only a guarantee for fuel costs, which was consistent with the existing SGOL program. Generator representatives argued for O&M costs to be included in the day-ahead guarantee. In November 2005 the Association of Power Producers of Ontario sent the IESO's CEO a letter suggesting that the proposed DACP favoured importers at the expense of domestic generation and informed the IESO it would not be able to support the DACP initiative unless the real-time and day-ahead programs include a guarantee for incremental O&M and profit.[109] The IESO included O&M in the DA-GCG guarantee soon after.

Initially, the IESO's rationale for guaranteeing O&M costs was that the additional guarantee was a response to stakeholder concerns that the DACP process benefitted importers over domestic

[107] Other reasons listed included: load growth, extended periods of hot weather, low hydro-electric energy available, environmental limitations to production due to heat and transmission system at its limit due to heat
[108] The IESO presentation noted that "New York will curtail Ontario's hourly transactions to protect their day-ahead transaction." At the time, New York had a full day-ahead market, while Ontario did not yet have any processes in place to commitment resources day-ahead.
[109] For more information on the Association of Power Producers of Ontario's letter regarding the proposed DACP, see the letter itself, available at: http://www.ieso.ca/Documents/consult/dayAhead/da_20051111-APPrO.pdf

generators.[110] That reason was amended in subsequent documentation to instead read as a response to stakeholder concerns that generators may be disincented to accept a day-ahead commitment because generators who accept day-ahead starts may incur greater costs compared to costs incurred in real-time.[111] Although the IESO did eventually provide a guarantee for O&M in the DACP, it refused further requests to include such costs in the RT-GCG.[112]

In 2009, responding to a January 2009 Panel recommendation[113], the IESO began a stakeholder initiative intended to increase the efficiency of the RT and DA-GCG programs by introducing competition for guarantees and strengthening the eligibility criteria required for obtaining IESO commitments. In similar fashion to the 2005 engagement, the IESO's initial position was to guarantee only fuel costs (i.e. start-up fuel) through the RT-GCG guarantee, only the DA-GCG would allow for start-up O&M costs. The IESO held to this position for several months.

In an echo of the result of the 2005 engagement, generator representatives continually requested that O&M be included in the RT-GCG until finally the IESO relented.[114] The IESO's rationale for implementing this guaranteed cost was to provide parity between the DA and RT programs.[115] Not unexpectedly, this decision to include O&M in the RT-GCG led to a surge in the cost of the RT-GCG program, see Figure 3-1 below.

[110] For more information on the IESO's initial rationalization for including O&M costs in the DA-GCG, see the IESO's Market Rule Amendment Proposal, page 8, available at: http://www.ieso.ca/Documents/tp/tp_174-3-MR-00303-R00-R05-AP-v1_0.pdf

[111] For more information on the IESO's final rationale for including O&M costs in the DA-GCG, see the IESO Board's decision, page 7, available at: http://www.ieso.ca/Documents/Amend/mr2006/MR_00303-R00-R05-BA.pdf

[112] For more information on the IESO's response to OPG's comments, see the IESO's response document prepared for the TP, page 2, available at: http://www.ieso.ca/Documents/tp2006/tp177-5a-DACP-Response-to-OPG-WS-Cover-Memo.pdf

[113] For more information on this recommendation, see the Panel's January 2009 Monitoring Report, pages 217-220, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/msp_report_200901.pdf

[114] *"It is noted that generators continue to request a guarantee of incremental operating and maintenance costs for start up and ramp to minimum loading point (non-minimum generation block period) for the real-time guarantee program. The IESO agreed to review this request and get back to generators.*

Follow-up: The IESO has updated the amendment to include incremental operating and maintenance costs incurred during start up and ramp to MLP for the real-time guarantee program can be submitted on form 1551 creating parity between the guarantee programs."

SE-80 Session Notes: June 10, 2009

[115] For more information on the IESO's rationale for guaranteeing start-up O&M costs through the RT-GCG, see the IESO Board's decision, page 4, available at:

The cost of the RT-GCG program spiked sharply in 2010, and in late 2011 the IESO began to audit generator cost submissions. Nine years after the introduction of the RT-GCG, the IESO exercised its authority under the Market Rules to review generator cost submissions. The IESO has stated that it has recovered $150 million in overpayments from generators. This figure accounts for overpayments through the former DA-GCG program as well as the RT-GCG program. The IESO did not provide a breakdown of recoupments by program.

In October 2011 the DA-GCG program was eliminated when it was replaced by the Enhanced Day-Ahead Commitment process (EDAC).[116] EDAC significantly changed the way generators offer and receive guarantees: all costs are offered in advance, with no after-the fact submissions. Generator's offers would be made in three 'parts' which included start-up cost, speed no-load cost,[117] and incremental energy cost. Successful generators would then receive a day-ahead guarantee for the total production cost of the commitment, based on that three-part offer. The program continued making financial guarantees to generators (and importers) to ensure that the costs they offered would be covered if they received insufficient revenue through the energy market. Notably, this program did not distinguish between fuel and O&M costs, but instead between energy, start-up, and speed no-load costs.

http://www.ieso.ca/Documents/icms/tp/2009/06/IESOTP_226_3b_MR_00356_R00_R02_Amendment_Proposal_v1_0.pdf

[116] For more information on the Panel's assessment of EDAC, see the Panel's January 2014 Monitoring Report, pages 154-174, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2012-Apr2013_20140106.pdf

[117] The IESO Market Manual for the enhanced DACP defines Speed no-load costs as "The cost to maintain a generation unit synchronized with zero net energy injected into the system for an hour." For more information on speed-no-load costs, see the IESO DACP training guide, page 14, available at: http://www.ieso.ca/Documents/training/DACPguide.pdf

3.2.3 The Cost of the RT-GCG Program

From 2003 through 2009 the RT-GCG program provided generators with guarantees for fuel costs only. Over that time average cost submissions per start were approximately $25,600 and payments were $4,600 per start. Since the introduction of guarantees for O&M costs in December 2009, the average cost guarantee per start has increased to over $47,000 and average payments per start increased to $22,400.

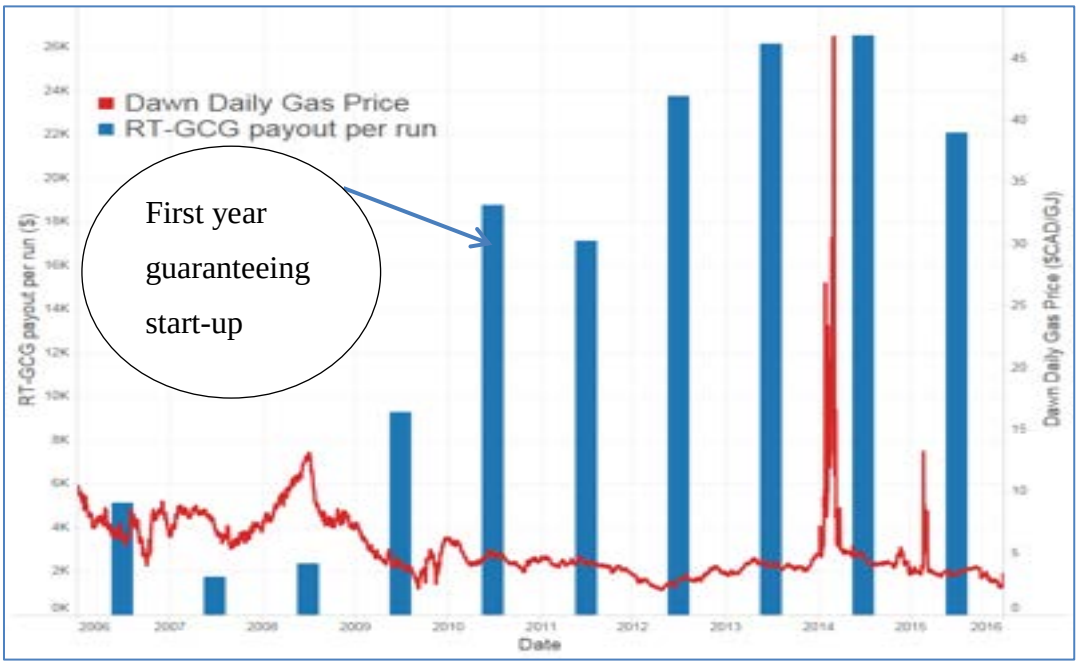
The guarantee of O&M costs represented a significant addition to the guarantee for fuel costs, especially when considering that the IESO instructs generators to start without knowing the start-up costs those generators later submit.

In total, the IESO has made RT-GCG payments to generators of over $400 million since January 2010, of which $280 million was to cover guaranteed start-up O&M costs.[118]

Figure 3-1 shows the average payouts per run through the RT-GCG program since 2006. It is easy to see the increase in average per run payouts associated with the O&M guarantee post 2010. The Panel has provided Dawn Daily Index gas prices as well. The gas price index demonstrates that the increase in payouts is not a consequence of increasing gas prices. The price spike in winter 2014 aside, natural gas prices have been decreasing since 2008 and are currently at very low levels.

[118] These figures do not reflect the $150 million in recoveries that the IESO has made through its audit of the day-ahead and real-time guarantee programs. Details regarding those recoveries (year, day-ahead vs. real-time program or cost type (fuel vs. O&M)) have not been made available.

Figure 3-1: Average RT-GCG Payments and Dawn Daily Gas Price
January 1, 2006 – December 31, 2015
($, $CAD/GJ)



3.2.4 Panel's Past Commentary on RT-GCG Programs

The Panel's previous commentary on the RT-GCG program has spanned a broad range of aspects of the program, from the technical parameters generators provide to the IESO to the inefficiency associated with after the fact cost submissions. The program is a regular topic of interest, and the Panel has commented on the program in 14 of its 27 semi-annual monitoring reports and made seven recommendations related to the program. In a number of instances the IESO made changes to the program in response to Panel recommendations.

Below is a brief summary of the various current features of the program that have been the subject of Panel recommendations:

- After-the-fact cost submissions mean the IESO starts generators knowing only their energy offers, and generators submit start-up costs after-the-fact.[119]

[119] For more information on this topic, see the Panel's January 2014 Monitoring Report, page 167, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2012-Apr2013_20140106.pdf

- The RT GCG program can provide more generous guarantee payments compared to the IESO's day-ahead guarantee program (the payments are more attractive because less revenue is counted against costs).[120]
- More generous real-time payments can lead some generators to avoid competing in the day ahead commitment program, potentially weakening competition in that program.[121]
- The cost allocation of the RT-GCG program has subsidized export uplifts. Although the majority of RT-GCG commitments occur in order to meet export demand, 40% of RT-GCG uplift costs caused by exporters have been allocated to Ontario consumers.[122]

While the Panel is of the view that the IESO's longer term solution would go a long way towards addressing the various issues with the program, the cost of the program remains too high to not address existing shortcomings in the interim. As the rest of this report will show, the cost of inaction is high, and the time to the enduring fix too far, not to move expeditiously to address the Panel's recommended changes.

3.2.5 The Need to Guarantee Costs

As part of a stakeholder engagement concerning the RT-GCG (SE-GCG) launched in October 2015, the IESO provided the following explanation regarding why the IESO has generation cost guarantees:

> "The IESO-administered markets schedule resources to ensure energy and operating reserve demands are met at any given time. If there is a disturbance on the electricity system or market demand increases, resources need to be ready to dispatch to meet system conditions. Not having enough resources online to meet changing conditions can have significant impacts on reliability.
>
> Some resources can take several hours to reach the point at which they are available for dispatch, called the minimum loading point (MLP). During the period between initiating

[120] Ibid, p. 168.
[121] Ibid, p. 171.
[122] For more information on how the cost allocation of the RT-GCG subsidizes export transactions, see the Panel's September 2014 Monitoring Report, pages 71-88, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2013-Oct2013_20140924.pdf

> a start to reaching MLP, a resource will incur costs as a result of starting up. Without assurance that the resource will be dispatched in real-time, a generator faces uncertainty that the resource will be able to recover the incremental costs of starting and ramping to MLP. As a result, some resources may be less likely to be offered when the IESO may need them to be available.
>
> To address this concern, the IESO introduced the Spare Generation On-Line (SGOL) program in 2003, now called the Real-Time Generation Cost Guarantee (RT-GCG) program. The IESO relies on this and other mechanisms such as the Day-Ahead Production Cost Guarantee (DA-PCG) program to incent participants to offer generation facility resources to the market in real-time."[123]

The IESO has also stated that the rules governing start-up O&M cost submissions have been administratively burdensome for both market participants (who, according to the IESO, are unclear at times what costs are recoverable and how to allocate them within the program) and the IESO.[124] The Panel observes that the IESO has undertaken a number of activities to clarify eligible costs, including: audits of market participant cost submissions, the issuance of an interpretation bulletin detailing eligible costs and the opening of SE-GCG which is meant, "…to develop a clearly defined and transparent cost recovery mechanism that reduces the scope and frequency of audits related to the RT-GCG program."[125]

The Panel has been an active participant throughout SE-GCG making three submissions to the IESO, the content of which is described in more detail below. The Panel believes that the IESO has not adequately articulated why the guaranteed recovery of certain costs, specifically, start-up O&M, is necessary in order to achieve the objectives of the program.

Given the above explanation regarding the need for the program and the Panel's concern regarding the extent of guaranteed costs, the Panel has examined two questions associated with the use of the RT-GCG program.

[123] For more information on the RT-GCG Cost Recovery Framework, see the IESO's framework document, available at: http://www.ieso.ca/Documents/consult/RTGCG/RTGCG-20151203-Design-Document.pdf
[124] Ibid, page 6
[125] Ibid, page 6

1. How often are RT-GCG committed units actually required in order to satisfy domestic energy demand and OR?

2. Is the guarantee of start-up O&M required to incent participants to offer into the market in real-time?

The Panel has found that the RT-GCG program is needed to satisfy domestic energy demand and OR in fewer than 1% of hours in which it was used to incent participants to offer in real-time, and that the current incentive is approximately $40 million per year larger than it needs to be. These findings are discussed in more detail in the following sections.

3.2.6 How often are RT-GCG Committed Units Required?

In the IESO's view, incenting participants to offer generation facility resources to the market in real-time is necessary for maintaining system reliability. The Panel has on more than one occasion asked the IESO to provide a detailed analysis supporting this statement.[126] No such study has been provided.

As part of the Panel's first submission to SE-GCG,[127] the Panel conducted its own reliability study. The Panel examined GCG commitments throughout 2014 to determine whether or not the IESO could meet domestic demand and OR requirements in real-time absent units committed under the RT-GCG program. EDAC satisfies forecasted Ontario demand and OR in the day-ahead timeframe, therefore any unit with incremental schedules to day-ahead, which includes all RT-GCG units, are scheduled to meet changes in supply and demand conditions from day-ahead to real-time.

The Panel's analysis found the following:

- In 2014, there was at least one unit committed through the RT-GCG program during 3,638 hours (42% of all hours in the year)

[126] For more information on these previous Panel recommendations, see the Panel's February 2011 and January 2014 Monitoring Reports, pages 86-96 and 154-174 respectively, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_20110310.pdf and http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2012-Apr2013_20140106.pdf

[127] For more information on this topic, see the Panel's official submission, available at: http://www.ieso.ca/Documents/consult/RTGCG/RTGCG-20151120-Market-Surveillance-Panel.pdf

- In 2014, absent units committed through the RT-GCG program, there were insufficient domestic resources available in real-time to meet supply and domestic demand changes from day-ahead in only 19 hours (0.5% of the hours in which there was a RT-GCG commitment), 10 of the 19 hours occurred on the same day

- During the 3,638 hours in which there was a RT-GCG commitment, the IESO committed an average of 412 MW, and a maximum of 1,377 MW

- During the 19 hours in which, absent units committed through the RT-GCG program, there were insufficient resources available in real-time to meet supply and domestic demand change from day-ahead, the average insufficiency was 177 MW, and never exceeded 495 MW.

In summary, the Panel found that in 2014, commitments through the GCG program were needed to meet domestic demand and OR needs in real-time in less than 1% of the hours in which a commitment actually occurred. In 2014, these needs were met at a cost to Ontario consumers of $61 million.

3.2.7 Is the Guarantee of Start-up O&M Necessary?

As discussed in section 3.2, start-up O&M was not a cost that was guaranteed in the RT-GCG program from 2003 through 2009. When the original RT-GCG program was implemented in 2003 (known then as the spare generation on-line program) the IESO made the decision to guarantee only the fuel costs of generators. All other costs associated with start-up and operation at a facility's Minimum Loading Point (MLP) were excluded from the guarantee.[128] The IESO's position and its supporting arguments for not guaranteeing O&M costs were included in material prepared for the Technical Panel in 2003:

> "Only fuel costs are proposed to [be] eligible for the [RT-GCG] guarantee for the following reasons, even though there may be other incremental costs associated with the start-up and operation of a generation facility at its minimum load point.

[128] For more information on past IESO decisions and rationale regarding O&M cost eligibility through the IESO's GCG programs, see the above section 3.2 "History of Guarantee Programs"

- Facilities eligible for this program will, by the nature of the guarantee of cost recovery, have an advantage over non-eligible facilities that can be available in real-time i.e. this program, to some extent, reduces the market value of quick-start facilities. Restricting the cost guarantee to fuel costs limits this advantage.
- Fuel costs are readily verifiable on the basis of public information e.g. natural gas, oil, coal prices and historical cost submissions. This facility of verification is expected to reduce the market participant effort required to determine the applicable costs and the need for IMO auditing of submitted costs, both of which should improve the administrative efficiency of the program."[129]

Six years later, the guarantee of start-up O&M was first introduced in an IESO submission to the TP on June 23, 2009. In that document, the IESO provides the following rationale for the inclusion of start-up O&M as a guaranteed cost,

> "This change [the inclusion of start-up O&M] would create parity between the real-time and day-ahead guarantee program since the day-ahead guarantee program already allows market participants to claim those [start-up O&M] costs."[130]

The Panel is not satisfied that "parity" alone is reason enough to justify the added cost of O&M. Moreover, this contradicts the IESO's earlier position in 2006, when it purposefully resisted creating parity between the two programs by refusing to add O&M to the RT-GCG.

Start-up O&M costs have accounted for 70% of the cost of the RT-GCG program since January 2010 ($280MM out of $405MM).

SE-GCG, launched by the IESO in late 2015, has been described by the IESO to be a discussion about how to guarantee start-up O&M costs in a defined and transparent manner that reduces the administrative burden of audits on participants and the IESO. To that end the IESO published a proposed RT-GCG cost recovery framework. While the Panel does not dispute that the many

[129] For more information see the IESO Board's decision, page 20, available at: http://www.ieso.ca/Documents/Amend/mr/mr_00235-R00-R05_BA.pdf
[130] For more information see the IESO Board's decision, page 4, available at: http://www.ieso.ca/Documents/Amend/mr2009/MR-00356-R00-R02-BA.pdf

costs which make up the IESO's proposed cost recovery framework are bona fide, it is not convinced that all of these are actually incremental to start-up and ramping to MLP. [131] What the Panel believes is critically missing from the discussion is any analysis or explanation as to whether the guaranteed recovery of start-up O&M costs is necessary to incent generators to come online in real-time to ensure that Ontario's reliability needs are met.

The Panel finds it illustrative that from 2003 through 2009, a time when O&M was explicitly excluded from the RT-GCG, there were over 6,000 RT-GCG unit commitments, including many by generators who participate in the RT-GCG program today. Clearly, the guarantee of O&M costs was not required to incent these generators to start in real-time from 2003 through 2009; the Panel suggests that it is also not required in 2016.

The RT-GCG program exists to support the reliable operation of the IESO-controlled grid; it does not exist to ensure that all of a generator's actual costs are recovered.[132] In the Panel's view, costs should only be guaranteed to the extent necessary to ensure that the ultimate reliability objective is achieved and no more.

[131] Examples of proposed eligible costs include: contracted labour, cost of permit fees, crane rentals, disposal of waste and temporary office trailers. For more information regarding O&M costs the IESO has determined are eligible for recovery see the IESO's presentation slides of May 26, 2016, slide 8-36, available at: http://www.ieso.ca/Documents/consult/RTGCG/RTGCG-20160526-Presentation.pdf

[132] Through written submissions to the IESO's RT-GCG SE, some participants have provided their own thoughts on the purpose/goal/objective of the RT-GCG program:

- "…the current goal of the program, which is to recover actual incurred costs." TransAlta submission, Nov. 20, 2015, page 1, available at: http://www.ieso.ca/Documents/consult/RTGCG/RTGCG-20151120-TransAlta.pdf
- "The framework document moves away from a main objective of the RT-GCG program – recovery of actual costs." Goreway submission, Nov. 20, 2015, page 1, available at: http://www.ieso.ca/Documents/consult/RTGCG/RTGCG-20151120-Goreway.pdf
- "OPG believes employing such a method undermines the purpose of the RT-GCG program to reimburse participants for their actual incremental costs incurred during start-up." OPG Submission, Nov. 20, 2015, page 1, available at: http://www.ieso.ca/Documents/consult/RTGCG/RTGCG-20151120-OPG.pdf
- "This [IESO proposed framework] is moving away from the original intent of the program which sought to allow generators to recover their actual costs incurred associated with starting that plant which were not able to be recovered elsewhere, do to other contracts / obligations, and to ensure that generators would be held whole." Northland Power Submission, April 15, 2016), page 1, available at: http://www.ieso.ca/Documents/consult/RTGCG/RTGCG-20160415-Northland-Power.pdf

3.2.8 The IESO's Proposed RT-GCG Market Rules Changes

The significant cost of the RT-GCG program has not gone unnoticed by the IESO. Indeed, the IESO has recently conducted audits of RT-GCG (and the former Day Ahead-GCG) participants, exercising its authority to do so under the Market Rules.[133] The audits resulted in the recovery of $150 million in ineligible costs that were initially paid by the IESO through both programs and then subsequently recovered during the audit. The results of the audits precipitated the launch of SE-GCG in October 2015. SE-GCG's objective was to "develop a clearly defined and transparent cost recovery mechanism that reduces the scope and frequency of audits related to the RT-GCG program."[134] The IESO proposed to change the rules governing the RT-GCG program because the audit results showed that participants were unclear at times what costs were recoverable under the RT-GCG program and the IESO views the current audit process as too burdensome for both participants and the IESO.

The Panel was an active participant throughout the stakeholder initiative making three submissions to the IESO. The Panel and/or its representatives also attended numerous SE-GCG meetings and webinars, and notes that generator representatives were the large majority of attendees at the meetings.

In its submissions the Panel made several requests and recommendations, including that the IESO should expand the scope of the SE to allow for the consideration of better aligning whether a cost is recoverable, with the stated reliability objective of the program, and whether lower cost alternatives to the current RT-GCG are available.[135] The IESO elected not to expand the scope of the SE, stating that exploring lower cost alternatives did not align with the objective of the initiative, which was to develop a clearly-defined and transparent cost recovery mechanism that reduces the scope and frequency of audits related to the RT-GCG program.[136]

[133] The audits covered submissions from January 1, 2006 through December 31, 2016. For more information on the IESO's audit results, see the IESO's response to stakeholder feedback, page 8, available at: http://www.ieso.ca/Documents/consult/RTGCG/RTGCG-20160415-IESO-Response-to-Stakeholder-Feedback.pdf
[134] For more information, see the IESO's framework document, available at: http://www.ieso.ca/Documents/consult/RTGCG/RTGCG-20151203-Design-Document.pdf
[135] For more information, see the Panel's submissions, available at: thttp://www.ieso.ca/Documents/consult/RTGCG/RTGCG-20160415-Market-Surveillance-Panel.pdf
[136] For more information, see the IESO's response to stakeholder feedback, page 4, available at: http://www.ieso.ca/Documents/consult/RTGCG/RTGCG-20151120-IESO-Response.pdf

The IESO has proposed to prescribe dollar amounts ($/GJ, $/start, $/MWh or $) for specific costs that the IESO has determined are eligible for recovery and has provided a long list of recoverable costs available to eligible market participants.[137]

Despite this extensive list of recoverable items, participants have expressed their concern on several aspects of the IESO proposed framework. These concerns include:

- Eligible fuel costs should account for distance from source
- The program should compensate generators for the fixed costs of gas storage and transportation because it is necessary for generators to secure storage and transportation services to start the facility
- The cost of full time staff performing planned maintenance work should be eligible for cost recovery through the GCG program. Not allowing reimbursement of internal labour costs may encourage participants to hire more expensive contracted labour in order to ensure recovery under the program. The program should not bias generators towards hiring contract staff for planned maintenance
- The program should allow for recovery of actual costs, not pre-approved universal costs

The message from generators is clear, their business is complicated and costly, and there seems to be no end to the number of costs that generator's believe should be covered by the IESO's RT-GCG. Additionally, each generator has its own method for managing the operation, maintenance and fuel costs of its facility.

The IESO's proposed solution would result in 97.5% of eligible start-up O&M costs being pre-approved through bilateral conversations with the IESO. These discussions would determine each facility's start-up O&M revenue for the ensuing three years.[138] It is unknown at this time when these discussions will be completed, or whether the results of those discussions will be made publically available.

[137] For more information regarding O&M costs the IESO has determined are eligible for recovery see the IESO's presentation slides of May 26, 2016, slides 8-36, available at:
http://www.ieso.ca/Documents/consult/RTGCG/RTGCG-20160526-Presentation.pdf
[138] The IESO has committed to reviewing the program at least once every three years.

Bilateral discussions aside, the Panel believes that each market participant is in the best position to manage and minimize its own costs, and does not need an explicit IESO guarantee to do so. Without an IESO guarantee, generators have a clear incentive to procure all of their fuel and O&M needs at the lowest cost reasonably possible. A blanket IESO guarantee risks numbing this incentive, as costs become a pass-through to ratepayers.

The Panel suggests that instead of risking introducing a bias into participants' business decisions, the IESO should simplify the suite of costs that it is prepared to guarantee. The Panel believes that the IESO should guarantee only those costs that can be demonstrated to support the reliable operation of the IESO-controlled grid. Based on experience from 2003 to 2009 inclusive,[139] the critical portion of the start-up guarantee is likely to include the fuel commodity cost and little else.

The Panel finds it instructive that the IESO's decision to not include O&M costs in the original set of guarantee payments (from 2003) was supported by a desire to limit the need for auditing submitted costs and to improve the administrative efficiency of the program. By reducing the scope of the current cost guarantee the IESO would succeed in achieving the objectives of SE-GCG: (1) increasing transparency of guaranteed costs; (2); further diminish the need for, and complexity of, audits; and (3) significantly reduce the administrative burden of the RT-GCG program both for participants and the IESO.

The IESO has stated that in the longer-term it will explore a transition from the RT-GCG to an optimized program similar to the Day Ahead Production Cost Guarantee (DA-PCG) program (which currently schedules non-quick start units based on their three-part offers).[140] The Panel supports that initiative, as it will result in more efficient unit commitment through a more refined scheduling process and a further emphasis on competition[141], however, as acknowledged by the IESO, this initiative will take many years to develop and implement.

[139] The original 2003 RT-GCG program guaranteed fuel costs required for start-up and minimum run-time operation, up to a unit's MLP.
[140] Three part offers refer to the start-up, speed-no-load and incremental energy costs that the IESO currently uses to schedule non-quick start generators in the day-ahead timeframe. Currently, only incremental energy offers are used when scheduling non-quick start units in real-time.
[141] In 2015, competitively offered start-up costs through EDAC averaged $14,607 per committed resource compared to $27,825 per resource through the RT-GCG's after-the-fact submissions.

In the interim, given that continuing to guarantee start-up O&M costs in the RT-GCG results in significant costs and administrative burden for little discernable benefit to the reliable operation of the grid, the Panel recommends that the IESO eliminate the guarantee for start-up O&M from the RT-GCG program. This action is expected to reduce the cost of the RT-GCG by approximately $30 million per year.

Recommendation 3-1

The Panel recommends that the IESO eliminate from the Real-time Generation Cost Guarantee program the guarantee associated with: (a) incremental operating costs for start-up and ramp to minimum loading point; and (b) incremental maintenance costs for start-up and ramp to minimum loading point.

Reducing the suite of costs guaranteed by the RT-GCG may have the positive side-effect of driving increased competition day-ahead. The EDAC accounts for generators' start-up, speed no-load and incremental energy costs when it schedules non quick-start generators day-ahead; only the lowest cost facilities, on an all-in cost basis, earn commitments. So long as the RT-GCG program exists in its current form generators have little incentive to vigorously compete in the EDAC[142] as they still have the chance to be committed in real-time without having to compete on start-up costs. Another reason for generators to prefer the current RT-GCG over the EDAC is the comparatively narrow set of revenues that are used to offset the real-time guaranteed costs[143] which is the subject of the next section.

3.2.9 Revenues Off-setting Guaranteed Costs

In its January 2014 monitoring report the Panel recommended that the IESO modify the RT-GCG program such that the revenues that are used to offset guaranteed costs under the program include any profit earned on output above a generation facility's MLP during its Minimum

[142] Participation in the EDAC is mandatory, however, three of the 10 largest gas-fired generation facilities in Ontario appear to offer in a manner that purposely avoids them being scheduled day-ahead; instead they only participate in the IESO markets through the RT-GCG.
[143] The Panel has previously reported on the competing incentives between the IESO's day-ahead and real-time guarantee programs. For more information, see the Panel's January 2014 Monitoring Report, pages 154-175 available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2012-Apr2013_20140106.pdf

Generation Block Run-Time (MGBRT) and profit on output generated after the end of the facility's MGBRT.[144] The Panel continues to support this recommendation.

The current treatment of revenues allows GCG payments to be made even when a generator recovers all its costs with market revenues. The Panel considers it appropriate to utilize a more comprehensive approach which would base the offsetting net revenues on the *entirety* of that unit's production.

The guarantee currently offered by the IESO includes the unit's offer price for operation at MLP for its MGBRT as well as eligible start-up costs. The Panel's proposed comprehensive offset methodology does not interfere with this guarantee; it simply provides that the payments under the guarantee will not exceed what was necessary to cover the guaranteed costs. The Panel does not consider it a reasonable outcome when a generator can operate profitably, on an all-in basis, and still receive a guarantee payment under the RT-GCG program.

For example, if during the course of a day's operation a generator earns net revenues in excess of its guaranteed costs, then it logically follows that no guarantee payment needs to be made; the unit has covered its costs through its market operations. However, if a generator profitably operates for some time after its MGBRT period but still does not earn sufficient net revenues to cover its guaranteed costs, then it is sensible to provide that unit with a guarantee payment based on the totality of its net revenues, not just those earned during its MGBRT.

The current revenue offset calculation ignores this logic, and allows generators to operate profitably over the course of the day and still receive a RT-GCG payment. The Panel's comprehensive offset methodology would eliminate such a result while still providing generators assurance that they will recover their eligible costs. Utilizing this comprehensive offset

[144] Currently, the RT-GCG program guarantees the following costs of market participants:

- start-up fuel and O&M (submitted after-the-fact)
- the offer cost for the unit's energy up to its MLP, over its MGBRT

The revenues used to offset these guaranteed costs include the following:

- energy revenue earned and CMSC received from synchronization and ramp to MLP
- energy revenue earned and CMSC received during MGBRT, up to the unit's MLP

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

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

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

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

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

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

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

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

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

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

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

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

such instances it seems that the RT-GCG program is undermining reliability as much as it is supporting it.

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

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

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

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

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

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

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

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

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

^Includes GCG payments
*Includes start-up costs

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

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

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

3.2.11 OR Revenue

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

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

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

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

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

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

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

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

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

Recommendation 3-2

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

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

3.2.12 Materiality of Implementing the Panel's Recommended Changes

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

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

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

3.2.13 Concluding Observations

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

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

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

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

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

[149] For more information see the IESO's Engagement Principles document, available at: http://www.ieso.ca/Documents/consult/IESO-Engagement-Principles.pdf

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

Table 3.4: Assessing the RT-GCG Program

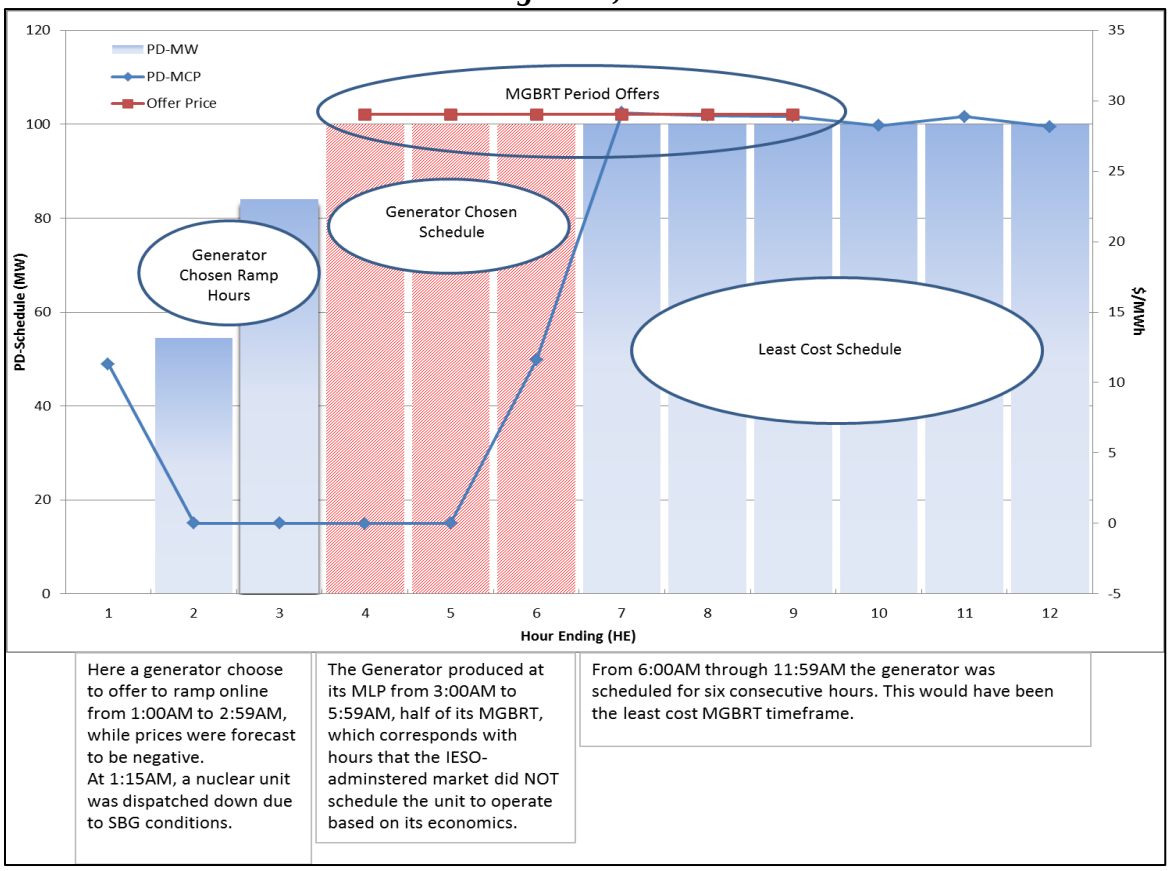
Criteria	Assessment	Implications
Cost Effectiveness	Costs have increased over 400% per start since the guarantee of start-up O&M despite decreasing fuel prices. MSP analysis shows minimal need for program to meet domestic reliability needs	Costs are in excess of requirements to meet domestic reliability,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

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

3.3 Appendix A

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

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



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

Chapter 4: Future Market Developments and Panel Recommendations

This chapter contains an update on future developments in the market and lists the recommendations contained in this report.

1 Future Development of the Market

There are a number of significant initiatives which are currently being undertaken by the IESO which are discussed in the sections that follow.

1.1 Market Renewal

In response to the operational challenges that had arisen under the existing market design, the IESO established the Electricity Market Forum (EMF) in March 2011. The EMF found that there was considerable scope for improvement.

Following on from the work of the EMF, the IESO undertook a series of reviews to investigate possible areas of improvements, which confirmed many of the findings of the EMF. These reviews included issues related to:

- Energy: The IESO reviewed intertie scheduling frequency, generator guarantee programs, the two schedule-system and HOEP.
- Capacity: The IESO established the demand response auction and is currently working with stakeholders on enabling capacity exports as a precursor to the development of broader incremental capacity auctions in the province.

The IESO is planning on evolving Ontario's electricity market to address known market inefficiencies and to develop a more dynamic marketplace in the future. The Market Renewal stakeholder engagement, which began in March 2016, is intended to set out specific market design changes to be implemented in the coming years and will define target timelines and work plans for completing these projects.

IESO materials published in April 2016 identify a number of projects that the IESO proposes to include in the work plan:[152]

- Two schedule replacement - moving to a pricing approach based on congestion pricing;
- Day-ahead market - introducing a day-ahead market to provide greater certainty to market participants and the IESO;
- Real-time unit commitment - improving real-time unit commitment to optimize over multiple hours with known costs;
- Interties - enhancing intertie scheduling to improve efficiency and flexibility;
- Demand response auction - evolving the demand response auction;
- Capacity trade - develop a system to enable capacity exports; and
- Incremental capacity auction - develop capacity auction for incremental capacity needs.

The IESO has since published more materials regarding the stakeholder engagement[153] and established the Market Renewal Working Group (MRWG).[154]

The MRWG consists of 13 market participants (and an additional 2 alternates) whose roles include assisting the IESO by providing valuable insight, technical expertise and advice to support the development and implementation of the Market Renewal initiatives as well as playing an active role in reviewing the preliminary analyses related to qualitative and quantitative aspects of the work plan.[155] The MRWG met in August and October of 2016 and has been solicited to provide input into the analysis regarding the potential benefits of carrying out the Market Renewal initiatives.

[152] For more information on the IESO materials regarding these proposed projects, see the IESO presentation "Future Market Design Considerations", available at: http://www.ieso.ca/Documents/consult/ME/ME-20160419-Market-Design-Considerations.pdf.
[153] For more information, see the IESO's Market Renewal stakeholder engagement webpage at: http://ieso.ca/Pages/Participate/Stakeholder-Engagement/Market-Renewal.aspx.
[154] For the IESO's Terms of Reference for the Market Renewal Working Group, see: http://ieso.ca/Documents/consult/ME/ME-20160624-Terms-of-Reference-Draft.pdf.
[155] For more information on the Market Renewal Working Group, see the IESO web page at: http://ieso.ca/Pages/Participate/Stakeholder-Engagement/Working-Groups/Market-Renewal-Working-Group.aspx.

The IESO proposes to finalize the report analyzing the estimated benefits from carrying out Market Renewal in the first quarter of 2017.[156]

This stakeholder engagement is in its early stages; April 2016 IESO materials state that the target date for finalization of the work plan is "Late 2016/Early 2017".[157] The Panel is very supportive of the proposed reforms and encourages the IESO to make developing and implementing these reforms on a timely basis a high priority.

1.2 Enabling System Flexibility

The IESO has launched a stakeholder engagement in parallel with the Market Renewal initiative to explore the range of options that can be used to provide greater flexibility to the IESO to manage the growing fleet of variable (primarily wind and solar) generating resources.[158] Similar to the Panel's findings in Chapter 2 of this report, the IESO has recognized the challenge that forecast errors pose to operations, and is soliciting options from stakeholders to help meet this need.

The IESO has asked market participants to identify potential solutions to the issue of greater required flexibility and will present a list of options for evaluation in the fourth quarter of 2016.[159] The Panel is supportive of the IESO's efforts to pursue market-based solutions to meet this identified need, and will be tracking this engagement with interest.

2 Update on Past Panel Recommendations and Investigations

2.1 Limiting CMSC Payments During Ramp-Down

In its June 2013 Monitoring Report, the Panel recommended that the IESO implement a permanent, rule-based solution to eliminate self-induced Congestion Management Settlement

[156] For more information, see the IESO presentation on the Proposed Approach to the Benefits Case Analysis available at: http://ieso.ca/Documents/consult/MRWG/MRWG-20160824-Presentation.pdf.
[157] For more information on the IESO's proposed timelines, see page 15 of the IESO's presentation "Developing a Market Renewal Workplan", available at: http://www.ieso.ca/Documents/consult/ME/ME-20160419-Developing-a-Workplan.pdf.
[158] For more information, see the Stakeholder Engagement webpage, available at: http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/Enabling-System-Flexibility.aspx
[159] For more information on the flexibility products which have been discussed by the IESO in the context of the stakeholder engagement, see the IESO's August 16, 2016 presentation at: http://ieso.ca/Documents/consult/ESF/ESF-20160816-Presentation.pdf.

Credit (CMSC) payments to ramping down generators. On June 24, 2015, the IESO approved a Market Rule amendment that would mitigate, but not eliminate such payments. However, the effective date of that Market Rule has been tied to the implementation of the required IT system changes at the IESO.[160] As such, the effective date of the market rule has been postponed several times, most recently on September 6, 2016.[161] As of the publication of this report, there is no publically available estimate of the effective date of the rule. The Panel estimates that this postponement has resulted in approximately $1.5 million in CMSC payments during ramp-down that would have been mitigated by the new market rule. The Panel will continue to monitor both the implementation of the rule and the payments accruing to generators as a result of the postponement.

2.2 IESO Concludes its Investigation into Abitibi-Consolidated Company of Canada and Bowater Canadian Forest Products Inc.

In August 2015, the Panel published a report on its investigation into the conduct of Abitibi-Consolidated Company of Canada (Abitibi) and its affiliate Bowater Canadian Forest Products Inc. (Bowater) (Resolute FP Canada Inc. (Resolute) had become the successor in interest to Abitibi and Bowater when the Panel's report was published), which concluded that the market participants engaged in gaming while operating as dispatchable loads. The public version of the investigation report, redacted to address confidentiality considerations, is available on the Ontario Energy Board's website.[162]

The Panel's gaming investigation related to CMSC payments received by the two market participants from January to August 2010 when their facilities were operating as dispatchable loads. The Panel found that both market participants engaged in gaming, and in doing so received $20.4 million in unwarranted CMSC payments over the eight-month period in question.

[160] For more information on Market Rule amendment 414, see the IESO's Market Rule Amendment Proposal, available at: http://www.ieso.ca/Documents/Amend/mr2015/MR_00414_R00_Amendment_Proposal_Ramp_Down_CMSC_v5.0.pdf

[161] For more information see the SE-111 stakeholder engagement webpage, available at: http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/SE-111.aspx

[162] See the Panel's "Report on an Investigation into Possible Gaming Behaviour Related to Congestion Management Settlement Credit Payments by Abitibi-Consolidated Company of Canada and Bowater Canadian Forest Products Inc.", available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Investigation_Report_CMSC_Abitibi_Bowater_2015.pdf

These CMSC payments were recovered through uplift and ultimately paid by Ontario consumers. In its report, the Panel encouraged the IESO to take whatever action may be open to it to recover the amounts paid to Abitibi and Bowater as a result of their gaming behaviour.

As a result of the IESO's own investigation into whether the two dispatchable loads breached the Market Rules, a non-compliance letter was issued to Resolute by the IESO in August 2016 for breach of the requirements of certain provisions of the Market Rules during the period October, 2004 to September, 2013. The non-compliance letter was issued as part of a settlement between the IESO and Resolute.

Without acknowledging or admitting any breach of the Market Rules, Resolute accepted, without contest, the IESO's determinations and agreed to repay $8,750,000. This payment is in addition to an earlier voluntary repayment of $1,825,010. Resolute also agreed to develop and implement an Internal Compliance Program in order to ensure that potential breaches of the Market Rules are detected and corrected.[163]

3 Recommendations in this Report

In chapter 2 the Panel reported on outcomes in the OR market and identified the need to consider more transparent real-time OR price signals. In particular, the IESO currently offers Control Action Operating Reserve in large blocks, which can mask the increasing value of OR as more Control Action Operating Reserve is scheduled.

Recommendation 2-1

Given the number of recent changes in the operating reserve market, the Panel recommends that the IESO review whether the real-time operating reserve prices transparently reflect the value of operating reserve as more Control Action Operating Reserve capacity is scheduled, and whether changes to Control Action Operating Reserve offer quantities and prices could enhance the efficiency of the operating reserve market.

[163] For more information on this and other enforcement sanctions, see the IESO's enforcement sanctions webpage, available at: http://www.ieso.ca/Pages/Participate/Market-Oversight/Sanctions.aspx

In chapter 3 the Panel reviewed the history of the IESO's RT-GCG program and commented on a number of significant concerns with that program. The Panel has made two recommendations that, together, would result in savings of approximately $40 million per year.

Recommendation 3-1

The Panel recommends that the IESO eliminate from the Real-time Generation Cost Guarantee program the guarantee associated with: (a) incremental operating costs for start-up and ramp to minimum loading point; and (b) incremental maintenance costs for start-up and ramp to minimum loading point.

Recommendation 3-2

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

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

TAB 10

AMPCO INTERROGATORY 12

Issue 4.0 Market Renewal Program (MRP)

4.0-AMPCO-12

INTERROGATORY

Ref: Exhibit D Tab 1 Schedule 2 Attachment 1

Please provide the organizational chart for MRP.

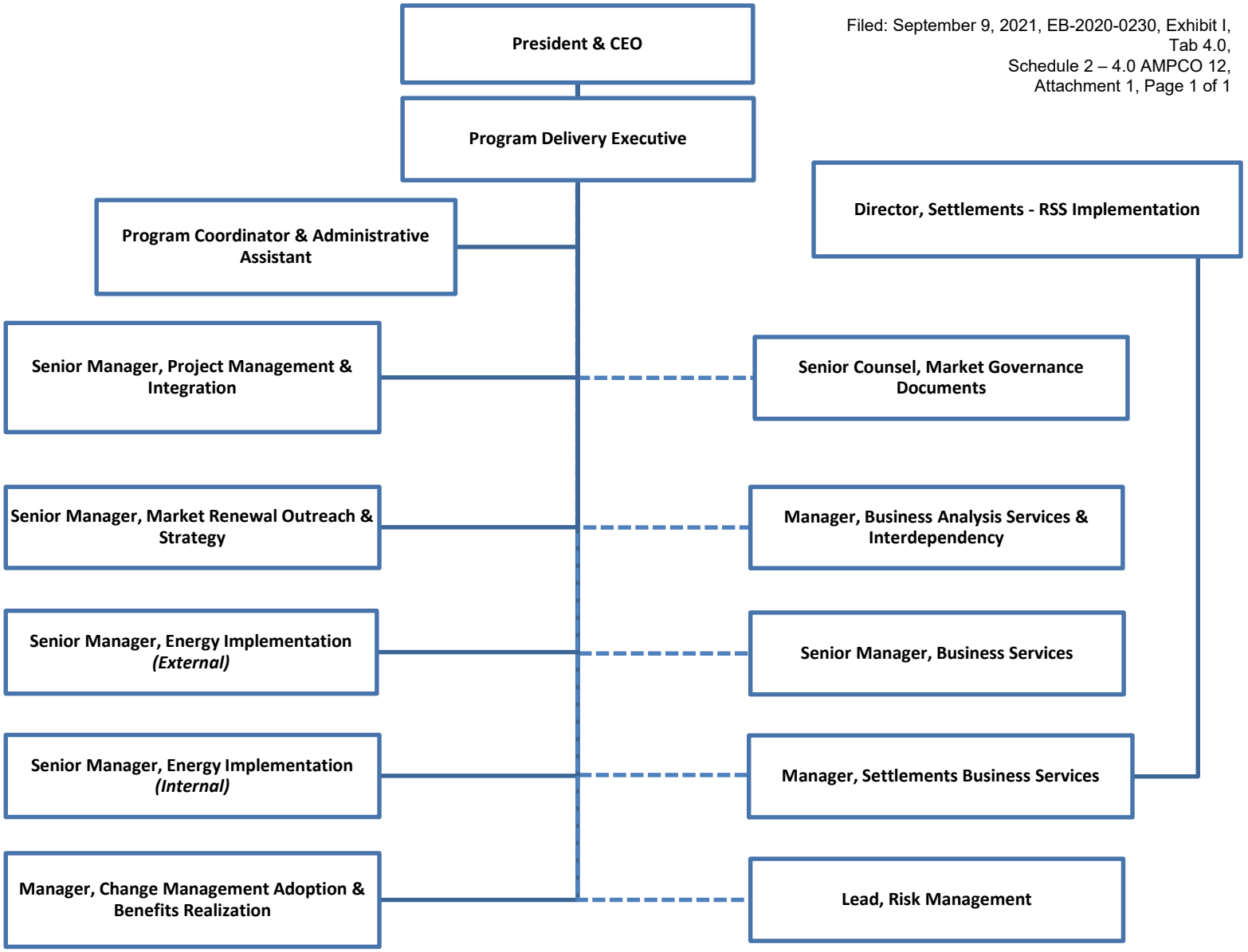
RESPONSE

See Schedule 2 - 4.0 AMPCO 12, Attachment 1 - MRP Org Chart. This org chart includes staff down to the initial senior manager, manager, and lead level.

Page Intentionally Blank

Market Renewal Program (MRP Energy) & Replacement Settlement Systems (RSS) Program (MRP-RSS Program)

Filed: September 9, 2021, EB-2020-0230, Exhibit I,
Tab 4.0,
Schedule 2 – 4.0 AMPCO 12,
Attachment 1, Page 1 of 1



Effective Date: July 5, 2021

Page Intentionally Blank

AMPCO INTERROGATORY 13

Issue 4.0 Market Renewal Program (MRP)

4.0-AMPCO-13

INTERROGATORY

Ref: Exhibit G Tab 2 Schedule 1 Page 2

The final detailed design was published in January of 2021.

a. Does the IESO anticipate any scope changes to the detailed design during implementation?

b. How will design scope changes be managed during implementation.

RESPONSE

a. The IESO does not anticipate any scope changes during implementation.

b. Transparency is one of the Market Renewal Program's guiding principles and the IESO regularly provides updates on the implementation phase of work during the monthly stakeholder engagement days. Design features may need to be changed if, for example, through the implementation phase it is discovered that it not feasible to implement the proposed features in the IESO's tools and systems. These items will be identified and raised with stakeholders through the IESO's engagement days.

Page Intentionally Blank

AMPCO INTERROGATORY 14

Issue 4.0 Market Renewal Program (MRP)

4.0-AMPCO-14

INTERROGATORY

Ref: Exhibit G Tab 2 Schedule 1 Page 3

The MRP Business Case was approved by the IESO Board of Directors (IESO Board) on October 23, 2019. The business case estimates $800 million in net system benefits expected to be realized in the first 10 years after implementation and a cost to deliver the project, including contingency, within a range from $151 million to $194 million.

a) Please identify the top 5 highest cost projects managed by the IESO in the last ten years.

b) Please identify any relevant lessons learned from these projects and how they have been incorporated into the implementation phase of MRP.

RESPONSE

a) 5 highest cost projects are:

1. MDM – Meter Data Management
2. Operations Readiness Initiative
3. Enhanced Day Ahead Commitment (EDAC)
4. Renewal Integration Initiatives
5. Unified Communications

b) Lessons Learned from our largest past projects/programs that were incorporated into the MRP include, but not limited to:

1. The importance of having a dedicated project team, including project management staff, business and IT leads and subject matter experts;
2. The need for enhanced stakeholder engagement and dedicated change management, adoption and benefits realization resources;
3. Robust Program governance. For the MRP program, the IESO has two levels of Governance: Director level project steering committee, and an Executive level steering committee.
4. Establishing a clear set of measures; For MRP, the IESO implemented clear project progress reporting metrics.
5. Engaging with the major vendor early to refine the design, cost and timelines; and

6. Drafting manuals and rules side by side so there is alignment in the language in those two sets of documents.

AMPCO INTERROGATORY 15

Issue 4.0 Market Renewal Program (MRP)

4.0-AMPCO-15

INTERROGATORY

Ref: Exhibit G Tab 2 Schedule 1 Page 3

The evidence states "As the IESO transitioned from detailed design to implementation, it provided a natural point of review of the schedule, budget, and risks – a common practice based on project management principles.

Please identify the body of project management principles the IESO is using to manage and monitor MRP.

RESPONSE

The IESO uses the following project management principles for all projects, including MRP.

- Adopting industry best practice in governance, controls, change management and delivery methodologies.
- Collaborating with customers and partners across the organization.
- Empowering team members by developing their skills and competencies.
- Streamlining and continually improving processes and products to ensure they efficiently achieve their objectives.
- Capturing lessons learned and leveraging these to improve how change is delivered.
- Clearly articulating roles and responsibilities and holding people accountable.
- Providing effective governance to manage changes in project scope, cost and timing.
- Examining and effectively managing risks throughout the project lifecycle, from initiation through delivery.
- Ensuring that quality and human performance is considered in all aspects of project delivery.
- Effectively managing human change to ensure the readiness of the customer to accept change.
- Ensuring value is provided in all of the services and keeping the customer experience in mind.

Page Intentionally Blank

AMPCO INTERROGATORY 16

Issue 4.0 Market Renewal Program (MRP)

4.0-AMPCO-16

INTERROGATORY

Ref: Exhibit G Tab 2 Schedule 1 Page 4 Table 2

Please add 2016 to 2020 actuals to the Table and add a column to present the Totals of each row.

RESPONSE

MRP began incurring costs in 2017, therefore values for 2016 have not been added to the table. 2017 – 2020 actuals have been added in the Table below.

Table 1: 2017-2020 Actual and 2021-2023 MRP Budget

(In $ millions)	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Budget	2022 Budget	2023 Budget	Total
Operating Expenses								
Compensation & Benefits	2.7	4.4	1.7	1.6	2.6	3.6	3.0	19.5
Professional & Consulting	1.9	2.2	1.2	0.4	0.9	1.2	0.8	8.6
Operating & Administration	0.2	0.4	0.2	0.1	0.1	0.1	0.1	1.2
Total Operating Expense	4.7	7.1	3.1	2.1	3.6	4.9	3.9	29.4
Capital Expenses								-
Compensation & Benefits	-	0.6	6.8	10.2	13.3	14.1	12.1	57.1
Professional & Consulting	-	0.2	2.5	2.7	4.1	4.8	4.3	18.6
Operating & Administration	0.1	0.3	0.9	11.8	14.1	17.7	10.7	55.6
Interest	-	-	0.1	0.3	1.0	2.3	3.3	7.0
Contingency	-	-	-	-	3.5	3.1	3.4	10.0
Total Capital Expenses	0.1	1.1	10.3	25.0	36.0	42.0	33.8	148.3
Total MRP Expenses	4.8	8.2	13.4	27.1	39.6	46.9	37.7	177.7

Page Intentionally Blank

AMPCO INTERROGATORY 17

Issue 4.0 Market Renewal Program (MRP)

4.0-AMPCO-17

INTERROGATORY

Ref: Exhibit G Tab 2 Schedule 1 Page 9 Table 10

a) Please add 2020 budget amounts to the table.

b) Please add 2022 and 2023 budget amounts to the table.

RESPONSE

Please find the updated table below:

Table 1: MRP FTEs Actual and Budget

MRP FTEs	2019 OEB Approved	2019 Actual	2020 Actual	2020 Budget	2021 Budget	2022 Budget	2023 Budget
Total Regular	35	36	36	44	45	44	44
Temporary	16	4	9	4	7	9	9
MRP Core FTEs	**51**	**40**	**45**	**48**	**52**	**53**	**53**
MRP Support FTEs	12	14	28	37	42	49	40
MRP FTEs Total	**63**	**54**	**73**	**85**	**94**	**102**	**93**

a) The 2020 budget reflects the 70 staff reflected in the 2020 – 2022 Business Plan and 15 IT support resources that were budgeted for the Market Renewal Program (MRP) but were not originally counted as MRP resources.

b) The 2021, 2022 and 2023 budget reflects the updated cost and schedule impacts noted in the 2021 Revenue Requirement Submission as well as the continued support from IT staff.

Page Intentionally Blank

AMPCO INTERROGATORY 18

Issue 4.0 Market Renewal Program (MRP)

4.0-AMPCO-18

INTERROGATORY

Ref: Exhibit G Tab 2 Schedule 1 Page 9 Table 10

Please provide a further breakdown of Regular Staff into Executive, Management and Non-Management Regular.

RESPONSE

Please the find updated table below.

Table 1: MRP FTEs by Executive, Management and Non-Management

MRP FTEs	2019 OEB Approved	2019 Actual	2020 Actual	2020 Budget	2021 Budget	2022 Budget	2023 Budget
Executive	-	-	-	-	-	-	-
Management	4	4	4	4	5	5	5
Non-Management	31	32	32	40	40	39	39
Total Regular	**35**	**36**	**36**	**44**	**45**	**44**	**44**
Temporary	16	4	9	4	7	9	9
MRP Core FTEs	**51**	**40**	**45**	**48**	**52**	**53**	**53**
MRP Support FTEs	12	14	28	37	42	49	40
MRP FTEs Total	**63**	**54**	**73**	**85**	**94**	**102**	**93**

Page Intentionally Blank

ED INTERROGATORY 1

Issue 4.0 Market Renewal Program (MRP)

Interrogatory # 4.0-ED-1

INTERROGATORY

Reference: Exhibit G-2-1, Attachment 1, Page 8 & 14

Preamble:

Page 8: "A thorough financial assessment of the new market design has concluded that the program is financially viable, delivering at least $750 million in net financial benefits to Ontario consumers over the first 10 years of implementation."

Page 14: "the Net Present Value for the Market Renewal Program Energy Stream has been assessed at $290 million - $450 million with a Benefits-to-Costs Ratio of 2.7 - 4.3"

Questions:

(a) Please describe in detail the degree to which the forecast $750 million in benefits from MRP are related to and dependent on continued use of gas-fired power generation.

(b) Approximately what percent of the benefits of MRP are related to and dependent on gas-fired power generation?

(c) Please re-estimate the benefits of MRP if the output of Ontario's gas plants is capped at a level that would produce 2.5 Mt CO2e per year and completely phased out by 2030. Please provide a response on a best efforts basis, making and stating assumptions and caveats as necessary. Please re-estimate both the gross benefits ($750 million), the net present value figures, and the benefits-to-costs ratio.

RESPONSE

(a) As noted in Procedural Order No. 1, the IESO's application is based on a business plan that has been reviewed and approved by the Minister of Energy and the review of the IESO's application should be focused on the IESO's OM&A and capital expenditures. The IESO's revenue requirement submission is not a proceeding to consider market design investments and incorporation of policy initiatives within MRP. In an effort to be responsive to this question, the IESO is providing the following information.

The quantifiable benefits were derived from more efficient unit commitment, improved intertie pricing, increased resource competition, and elimination of unwarranted CMSC payments. These benefits would result from the implementation of MRP regardless of the supply mix in use as the benefits come from better scheduling and price signalling of

resources to meet system needs in a least cost manner using improved mathematical calculations.

(b) The benefits result from improved scheduling and pricing signalling of resources to meet system needs in a least cost manner and do not distinguish between the type of resources used.

(c) The IESO has not re-estimated benefits included in the MRP Business Case as there is no provincial policy that is mandating phasing out of gas-fired power generation.

ED INTERROGATORY 2

Issue 4.0 Market Renewal Program (MRP)

Interrogatory # 4.0-ED-2

INTERROGATORY

Reference: Exhibit G-2-1, Attachment 1

Questions:

(a) What are the expected ongoing costs for MRP that would persist annually beyond 2030? Please provide a breakdown of these by type.

(b) What are the expected ongoing benefits for MRP that would persist annually beyond 2030? Please provide a breakdown of these by type.

(c) What expected ongoing benefits would persist annually beyond 2030 for MRP if gas-fired generation is eliminated by the end of 2030, all else equal? Please provide a breakdown of these by type.

RESPONSE

(a) Amortization of investments in MRP will begin to increase annual operating costs once MRP goes into service in 2023. The overall project costs will be amortized over 15-20 years resulting in an annual amortization expense of $7.4 - $9.9 million.

(b) A thorough financial assessment of the new market design has concluded that the program is financially viable, delivering $800 million in net financial benefits to Ontario consumers over the first 10 years of implementation. The 2019 Business Case only assessed the benefits within the first 10 years of implementation.

(c) As noted in Procedural Order No. 1, the IESO's application is based on a business plan that has been reviewed and approved by the Minister of Energy and the review of the IESO's application should be focused on the IESO's OM&A and capital expenditures. The IESO's revenue requirement submission is not a proceeding to consider market design investments and incorporation of policy initiatives within MRP. This question is outside of scope as the MRP Business Case only assessed the benefits within the first 10 years of implementation. The IESO has not re-estimated benefits included in the MRP Business Case as there is no provincial policy that is mandating phasing out of gas-fired power generation.

Page Intentionally Blank

ED INTERROGATORY 3

Issue 4.0 Market Renewal Program (MRP)

Interrogatory # 4.0-ED-3

INTERROGATORY

Reference: Exhibit G-2-1, Attachment 1, Page 9

Questions:

(a) Please describe qualitatively how MRP will likely impact the output of Ontario's gas plants as a share of Ontario's electricity supply, all else equal. Please also estimate the impacts, if any, as a % change and kWh change annually in Ontario's gas plant output in comparison to what would occur without MRP.

(b) Please describe qualitatively how each specific element of MRP (the single schedule market, the day-ahead market, and the enhanced real-time unit commitment project) will likely impact the output of Ontario's gas plants as a share of Ontario's electricity supply, all else equal. Please also estimate the impacts, if any, as a % change and kWh change annually in Ontario gas plant output in comparison to what would occur without MRP.

To address uncertainties, please make and state assumptions, simplifications, and caveats as necessary.

RESPONSE

(a) As noted in Procedural Order No. 1, the IESO's application is based on a business plan that has been reviewed and approved by the Minister of Energy and the review of the IESO's application should be focused on the IESO's OM&A and capital expenditures. The IESO's revenue requirement submission is not a proceeding to consider market design investments and incorporation of policy initiatives within MRP. In an effort to be responsive to this question, the IESO is providing the following information. All things equal, it is expected that MRP will help to increase non-emitting resources as a proportion of Ontario's electricity supply. The proportion change (%) is difficult to estimate due to market conditions and market participant behaviour. As it is very difficult to predict future market conditions and market participant behaviour, the IESO does not conduct this kind of modelling.

(b) The Single Schedule Market (SSM) will provide the foundation for better market operations as it will send accurate locational prices to Market Participants (suppliers and price responsive loads) that better reflect system needs and constraints. The SSM will eliminate the two-schedule system and the need for out-of-market real time congestion

payments by introducing locational prices that create alignment between pricing and dispatch on the system. Market prices will account for congestion and losses and will reflect the true costs of producing electricity at a given place and time.

Gas Market Participants, will benefit from the improved certainty provided by a Day-Ahead Market (DAM) in their own operations. The IESO will time the completion of the DAM specifically for the timely gas nomination window to provide gas generators with more certainty on gas procurements.

The Enhanced Real-Time Unit Commitment (ERUC) initiative will create a level playing field for all resource types through three-part offers which will include energy, start-up and speed-no-load costs thus increasing transparency and competition within the commitment process. ERUC will result in pre-dispatch schedules and unit commitments that better reflect the total cost of Non-Quick Start (NQS) resources that are based on a longer, more efficient optimization timeframe.

However, as it is very difficult to predict future market conditions and market participant behaviour, the IESO does not conduct the kind of modelling described in the interrogatory.

ED INTERROGATORY 4

Issue 4.0 Market Renewal Program (MRP)

Interrogatory # 4.0-ED-4

INTERROGATORY

Reference: Exhibit G-2-1, Attachment 1, Page 35

Preamble:

> "Improved price signal for flexibility: under the current two-schedule design, price signals for resources to provide flexibility by ramping up or down to meet demand fluctuations are muted and based on an unconstrained system. With the introduction of SSM, the use of actual resource ramp rates and consideration of system constraints will produce accurate and transparent prices that will better value flexibility and incentivize resources to respond and invest to meet ramping needs."

Questions:

(a) Please describe how the change described above will impact each resource type in general (e.g. gas, wind, solar, storage, etc.). In particular, please address whether the change will in general or in aggregate cause that resource type to be dispatched more or less often.

(b) Will the change described above cause resource types that are easier to dispatch quickly to be dispatched more often?

RESPONSE

(a) Replacing the two-schedule market with a Single Schedule Market (SSM) with locational pricing is expected to enhance reliability, increase operational certainty, and significantly reduce system costs paid for by consumers. Impacts to individual resources are dependent on the market participant's costs and offer strategies, which the IESO does not model and therefore cannot provide comment.

(b) The introduction of the SSM with locational pricing aligned with dispatch will ensure resources are responding to the right incentives and price signals for dispatch, reducing costs and enabling better decision-making. Resources will continue to be scheduled based on economics.

Page Intentionally Blank

ED INTERROGATORY 5

Issue 4.0 Market Renewal Program (MRP)

Interrogatory # 4.0-ED-5

INTERROGATORY

Reference: Exhibit G-2-1, Attachment 1, Page 36

Preamble:

> "Resource commitment plays an important role in the electricity market as it provides time and certainty to NQS resources, such as a combined-cycle gas turbine facility, to make necessary arrangements to produce energy. As explained previously, the current commitment process does not take all this information into account when making commitments, leading to inefficient resource selections. The more efficient commitment process will be designed to consider all resource costs and respect individual operational characteristics over multiple hours of the day. As a result, the inefficiency costs associated with today's commitment process will be eliminated."

Questions:

(a) Please describe how the change described above will impact each resource type in general (e.g. gas, wind, solar, storage, etc.). In particular, please address whether the change will in general or in aggregate cause that resource type to be dispatched more or less often.

(b) Will the change described above cause resource types that are easier to dispatch quickly to be dispatched more often?

(c) Because resource commitment provides time and certainty to NQS resources, such as a combined-cycle gas turbine facility, to make necessary arrangements to produce energy, will this change likely result in an increase in output from combined-cycle gas facilities on an annual basis? If yes, by approximately how much (% and MWh)?

RESPONSE

(a) As it is very difficult to predict future market conditions and market participant behaviour, the IESO does not conduct this kind of modelling.

(b) Resources will continue to be scheduled based on economics. As it is very difficult to predict future market conditions and market participant behaviour, the IESO does not conduct this kind of modelling.

(c) As it is very difficult to predict future market conditions and market participant behaviour, the IESO does not conduct this kind of modelling. See response to Schedule 6 - 4.0 ED 3a).

ED INTERROGATORY 6

Issue 4.0 Market Renewal Program (MRP)

Interrogatory # 4.0-ED-6

INTERROGATORY

Reference: Exhibit G, Tab 2, Schedule 1, Plus Attachment(s), Page 3

Exhibit G-2-1, Attachment 1, Page 8 & 12

Preamble:

Page 3: "The business case estimates $800 million in net system benefits expected to be realized in the first 10 years after implementation"

Page 8: "A thorough financial assessment of the new market design has concluded that the program is financially viable, delivering at least $750 million in net financial benefits to Ontario consumers over the first 10 years of implementation."

Page 12: "Better scheduling and commitment of resources in the real-time operating timeframe delivering system-wide efficiency benefits of over $500 million over the first 10 years of operating the new market design.

Elimination of approximately $450 million of unnecessary Congestion Management Settlement Credits over the first 10 years of operating the new market design. These benefits will accrue directly to Ontario consumers."

Questions:

(a) Please reconcile the three different benefits estimates cited above. Please include a table with a breakdown of the reconciliation.

RESPONSE

(a) The Net Present Value (NPV) analysis is a valuation tool and is used extensively across finance and accounting for determining the value of a capital project. If the NPV is positive, that means that the value of the benefits (in today's dollars) is greater than the project costs and vice-versa

Table 1: Breakdown of Reconciliation

Source of Savings	Description	NPV
Constrained off CMSC	Assets receiving constrained-off CMSC will no longer receive these payments. These are payments on top	$450M (range of $360M to $540M)

Source of Savings	Description	NPV
	of current regulated and contract payments, so generators' fixed rates will not be impacted.	
Market Efficiencies. Page 12.	More efficient use of interties (particularly exports), better unit commitment and enhanced competition will result in better asset utilization and reduced natural gas burn, avoiding fuel cost.	$525M (range of $500M to $550M)
Total Benefits		$975M (range of 860M to 1,090M)
MRP Energy Project Costs		$176M (range of $157M to $200M)
Expected Net Benefits (subtract total costs from total savings). Page 3.		$799M (rounded up to $800M, and range of $660 to $933M)

At the time of publication of the MRP Business Case, the IESO was using analysis, simulation, and best available information to forecast the range and costs. Within the Business Case are values that reflect a range of possibility, including the project costs. The "at least $750 million" was derived from using the mid-level possible project costs ($176 million), using a very conservative view of the benefits ($975 million), and rounding down to provide stakeholders the assurance that the project is on very sound financial footing even when looking at the most conservative scenarios. As the project proceeds, it is more common to see the figure of $800 million in net benefits in MRP materials, and the IESO will continue to report on project benefits and costs.

ED INTERROGATORY 7

Issue 4.0 Market Renewal Program (MRP)

Interrogatory # 4.0-ED-7

INTERROGATORY

Reference: Exhibit G-2-1, Attachment 1, Page 8 & 12

Preamble:

Page 8: "A thorough financial assessment of the new market design has concluded that the program is financially viable, delivering at least $750 million in net financial benefits to Ontario consumers over the first 10 years of implementation.

Page 12: "Better scheduling and commitment of resources in the real-time operating timeframe delivering system-wide efficiency benefits of over $500 million over the first 10 years of operating the new market design.

Elimination of approximately $450 million of unnecessary Congestion Management Settlement Credits over the first 10 years of operating the new market design. These benefits will accrue directly to Ontario consumers."

Questions:

(a) Will all of the $750 million in net financial benefits accrue to energy consumers?

(b) If not, please estimate the benefits ($) that will accrue to energy consumers and recalculate the NPV based only on those benefits accruing to energy consumers.

(c) Will a portion of the $750 million in net financial benefits accrue to resource/generation owners? If yes, approximately how much?

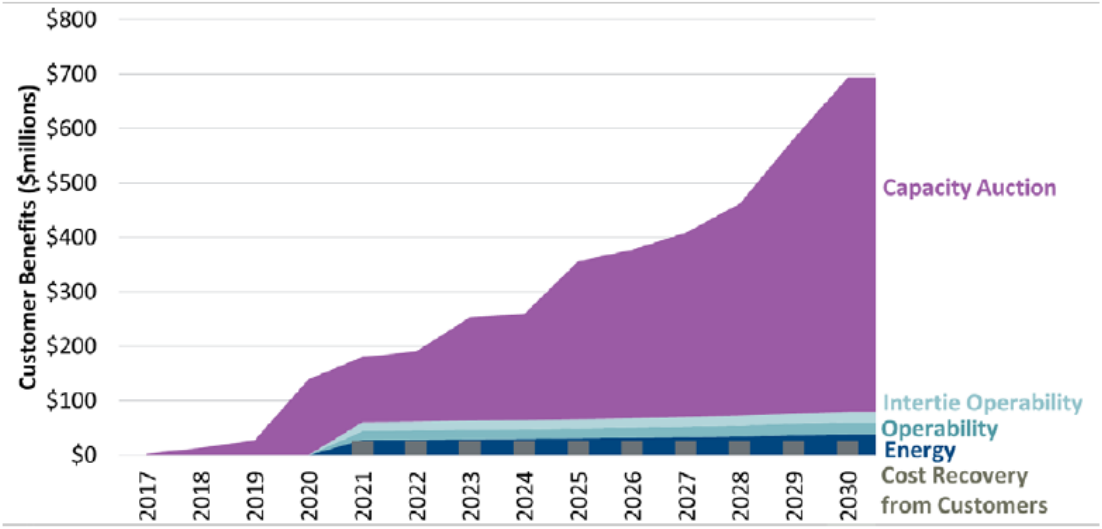
(d) According to the Brattle Group report[1] (p. 26), "The day-ahead settlement also allows natural-gas generators to procure much of their fuel on a day-ahead basis, which reduces fuel-related intra-day balancing costs." Approximately how much of the $750 in net financial benefits is attributable to this factor? Will this benefit accrue to gas plant owners or consumers? Please explain and estimate the division between beneficiaries.

(e) Page 108 of the Brattle Group report identifies the share of monetized efficiencies that will accrue to customers (pasted below). Please (i) reconcile these figures with the IESO figures, (ii) explain the difference in estimates, (iii) produce and updated figure with the IESO's best estimates.

[1] Brattle Group, *The Future of Ontario's Electricity Market: A Benefits Case Assessment of the Market Renewal Project*, prepared for the IESO, April 20, 2017.

(f) Please file the Brattle Group report for ease of reference by an exhibit number in this proceeding.

Figure 24
Estimated Customer Share of Efficiency Benefits from Market Renewal
(Excludes Customer Benefits from Avoided Transfer Payments, Gaming, and Other Unquantified Benefits)



Notes:
Capacity exports start in 2017 and the capacity auction begins in 2020. Energy and operability reforms begin in 2021. Once Projects come into service, the IESO recovers costs based on expected life of the investment. Cost recovery is small compared to large sector benefits.

RESPONSE

(a) Yes.

(b) See response to a).

(c) No.

(d) This was not calculated as a part of the quantifiable benefits. As identified in the IESO's response to a), the quantified benefits of MRP as specified in the MRP Business Case will accrue to consumers.

(e) Please note that the 2017 MRP Benefits Case "Brattle Group Report" was an initial study to confirm directionally that MRP would provide sufficient benefits and to guide the IESO to pursue a more formal business case. The subsequent 2019 MRP Business Case is more relevant given it used information specific to Ontario as inputs for the financial assessment of benefits. The IESO also notes that the OEB's decision in EB-2019-0002 ordered the IESO to include the MRP Business Case within this filing, which has been done.

(f) See response to e) above. The requested report was included previously in EB-2019-0002, Exhibit I, Tab 6.1, Schedule 10.21, Attachment 1. A link to the requested report is also provided here[2].

[2] https://ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/Benefits-Case-Assessment-Market-Renewal-Project-Clean-20170420.ashx

Page Intentionally Blank

ED INTERROGATORY 8

Issue 4.0 Market Renewal Program (MRP)

Interrogatory # 4.0-ED-8

INTERROGATORY

Reference: Exhibit G-2-1, Attachment 1, Page 8 & 12

Preamble:

Page 8: "A thorough financial assessment of the new market design has concluded that the program is financially viable, delivering at least $750 million in net financial benefits to Ontario consumers over the first 10 years of implementation."

Page 12: "Better scheduling and commitment of resources in the real-time operating timeframe delivering system-wide efficiency benefits of over $500 million over the first 10 years of operating the new market design.

Elimination of approximately $450 million of unnecessary Congestion Management Settlement Credits over the first 10 years of operating the new market design. These benefits will accrue directly to Ontario consumers."

Questions:

(a) The Brattle Group report[1] found that "assume that only 66–72% of the potential benefits from energy and internal operability enhancements estimated in Sections III and IV will be achieved under Market Renewal, absent amendments to existing contracts and regulated rate structures." (see p. 85). Does the IESO agree? If not, please provide its estimate.

(b) Will all of the $750 million in net financial benefits accrue to energy consumers absent amendments to existing contracts and regulated rate structures as described in the Brattle Group report? If not, please quantify the amount that would not be realized.

(c) Is the IESO implementing the "amendments to existing contracts and regulated rate structures" as described in the Brattle Group report on page 85? Please list each amendment needed and whether they are being implemented.

RESPONSE

(a) Please note that the 2017 MRP Benefits Case "Brattle Group Report" was an initial study to confirm directionally that MRP would provide sufficient benefits and to guide the IESO

[1] Brattle Group, *The Future of Ontario's Electricity Market: A Benefits Case Assessment of the Market Renewal Project*, prepared for the IESO, April 20, 2017.

to pursue a more formal business case. The subsequent 2019 MRP Business Case is more relevant given it used information specific to Ontario as inputs for the financial assessment of benefits. The IESO also notes that the OEB's decision in EB-2019-0002 ordered the IESO to include the MRP Business Case within this filing.

(b) The benefits of MRP as described in the MRP Business Case were not based on amendments to existing contracts or rate regulated structures.

(c) All contracts for facilities that participate in the IESO-administered market will require amendments that are consistent with the provisions of the contract, which can include changing references to the Hourly Ontario Energy Price, and enabling participation in the Day-Ahead Market.

ED INTERROGATORY 9

Issue 4.0 Market Renewal Program (MRP)

Interrogatory # 4.0-ED-9

INTERROGATORY

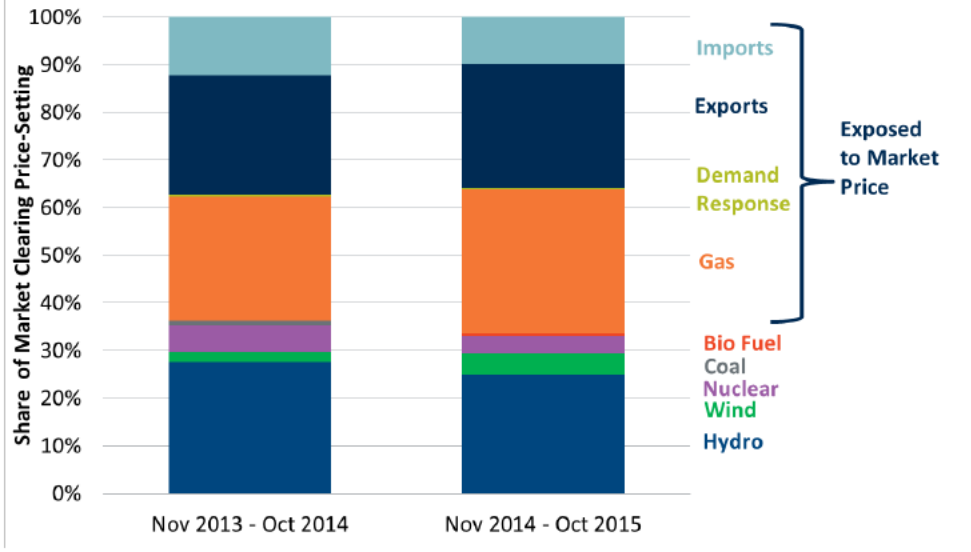
Reference: Exhibit G-2-1, Attachment 1, Page 8 & 12

Questions:

(a) Do the estimated $750 million in net benefits relate to resources exposed to market prices? If not, (i) please explain why not, (b) estimated the percent of benefits attributable to resources exposed to market prices, and (c) explain how benefits can be attributable to resources not exposed to market prices that recoup their costs minus HOEP through the GA.

(b) The Brattle Group report[1] describes includes a chart of resources that are and are not exposed to market prices on page 85 (pasted below). Does the IESO believe this is accurate? Please recreate this for 2019 and forecast for 2030, making and stating assumptions, simplifications, and caveats as necessary.

Figure 19
Marginal Price-Setting Resources on an Hour-Ahead Basis in Ontario



Sources and Notes:
Hour-ahead marginal resources, adapted from Ontario Energy Board (2016b), Figure 1-7.

[1] Brattle Group, *The Future of Ontario's Electricity Market: A Benefits Case Assessment of the Market Renewal Project*, prepared for the IESO, April 20, 2017.

RESPONSE

(a) Please note that the 2017 MRP Benefits Case "Brattle Group Report" was an initial study to confirm directionally that MRP would provide sufficient benefits and to guide the IESO to pursue a more formal business case. The subsequent 2019 MRP Business Case is more relevant given it used information specific to Ontario as inputs for the financial assessment of benefits. The IESO also notes that the OEB's decision in EB-2019-0002 ordered the IESO to include the MRP Business Case within this filing.

The benefits calculated in the MRP Business Case accrue to Ontario electricity consumers based on reducing the inefficiencies of the current energy market. These benefits will accrue regardless of whether resources are contracted, rate regulated, or operating on a merchant basis. This is due to the benefits of MRP coming from reducing the inefficiencies of the current energy market through better scheduling and commitment (I.e. choosing the least cost set of resources to meet system needs).

(b) See response to Schedule 2 - 4.5 AMPCO 30. Calculating the resources that are contracted and rate-regulated vs. merchant is not required as the benefits of MRP will accrue to consumers regardless of this distinction.

ED INTERROGATORY 10

Issue 4.0 Market Renewal Program (MRP)

Interrogatory # 4.0-ED-10

INTERROGATORY

Reference: Exhibit G-2-1, Attachment 1, Page 8 & 12

Preamble: The Brattle Group report states the following at page 100:

> "**Reduced curtailment and spilling of non-emitting resources.** Certain frictions in the current market design, including intertie scheduling, preclude the IESO from fully utilizing all resources with flexibility on the system. Moreover, incentives for flexible resources are insufficient and not market-driven. This results in the unnecessary curtailment and spilling of non-emitting low-marginal-cost resources such as hydro, wind, and nuclear generation. The curtailed output from these resources cannot be utilized to meet energy needs. Compared to an alternative design that absorbs this energy for productive use, the current design increases production costs and carbon emissions, or results in forgone export market revenues. Market Renewal will increase the extent to which Ontario can utilize its non-emitting resources without curtailments by better enabling system flexibility."[1]

Questions:

(a) MRP has been developed further since that report. Will the current iteration of MRP capture the benefit described above? Please explain in detail, including a discussion of whether all or part of this benefit will be realized.

(b) Other things equal, will MRP increase or decrease the non-emitting resources as a proportion of Ontario's electricity supply? Please estimate the proportion change (%) on a best-efforts basis.

RESPONSE

(a) See response to Schedule 2 - 4.5 AMPCO 30 with regard to references to the Brattle Report. Further, the financial benefits associated with a day-ahead market (improved consumption and investment, hydro and system optimization, reduced gaming opportunities as well as those associated with future improvements and enabling greater and diverse market participation) have not been quantified. Replacing the two-schedule market to a single schedule market with locational pricing is expected to enhance

[1] Brattle Group, *The Future of Ontario's Electricity Market: A Benefits Case Assessment of the Market Renewal Project*, prepared for the IESO, April 20, 2017.

reliability, increase operational certainty, and significantly reduce system costs paid for by consumers. These benefits are expected, but the scale of benefits will be influenced by many factors that make them difficult to predict with certainty.

(b) Other things equal, it is expected that MRP will help to increase non-emitting resources as a proportion of Ontario's electricity supply. The proportion change (%) is difficult to estimate due to market conditions and market participant behaviour. As it is very difficult to predict future market conditions and market participant behaviour, the IESO does not conduct this kind of modelling.

ED INTERROGATORY 11

Issue 4.0 Market Renewal Program (MRP)

Interrogatory # 4.0-ED-11

INTERROGATORY

Reference: Exhibit G-2-1, Attachment 1

Preamble: The Brattle Group report forecasts a "likely reduction in gas sales" on page 112.[1]

Questions:

(a) Was this forecast reduction attributable to the energy, operations, or capacity projects as described by Brattle Group?

(b) Is the IESO still forecasting a reduction in gas sales due to MRP (all other things equal)? If yes, by approximately how much (m3)? If not, why not and what has changed?

RESPONSE

(a) Please note that the 2017 MRP Benefits Case "Brattle Group Report" was an initial study to confirm directionally that MRP would provide sufficient benefits and to guide the IESO to pursue a more formal business case. The subsequent 2019 MRP Business Case is more relevant given it used information specific to Ontario as inputs for the financial assessment of benefits. The IESO also notes that the OEB's decision in EB-2019-0002 ordered the IESO to include the MRP Business Case within this filing, which has been done.

(b) See response to Schedule 6 - 4.0 ED 10. As it is very difficult to predict future market conditions and market participant behaviour, the IESO does not conduct this kind of modelling.

[1] Brattle Group, *The Future of Ontario's Electricity Market: A Benefits Case Assessment of the Market Renewal Project*, prepared for the IESO, April 20, 2017.

Page Intentionally Blank

ED INTERROGATORY 12

Issue 4.0 Market Renewal Program (MRP)

Interrogatory # 4.0-ED-12

INTERROGATORY

Reference: Exhibit G-2-1, Attachment 1

Preamble: The Brattle Group report states as follows on page 114:

> **What Is the Role of Electricity Markets in Curbing Carbon Emissions?**
>
> Wholesale electricity markets and capacity auctions offer a powerful tool for policymakers intent on reducing carbon emissions from the electric sector. Market-based carbon policies, including carbon taxes and cap-and-trade regimes, attempt to accurately reflect the societal costs of carbon in the price of any commodity whose production creates carbon emissions.
>
> Electricity is one such commodity. Wholesale electricity markets can be harnessed to reduce carbon emissions from power plants. Electricity markets naturally complement cap-and-trade policies by integrating carbon allowance costs into the energy offer prices that fossil plants submit to the system operator. These offers therefore accurately reflect production costs, including the cost of carbon emissions. The system operator then dispatches the plants that minimize total cost to meet load and maintain reliability. Plants with high emission rates run less as their costs increase relative to plants with lower emission rates. Thus, the energy market efficiently reduces carbon emissions in the lowest-cost manner. Capacity markets offer an opportunity to enhance carbon policy effectiveness through long-term investment and retirement decisions. Suppliers offering into a capacity auction take into account their expected carbon costs and energy market net revenues. This makes lower-emitting resources more competitive compared to higher-emitting resources. Over time this incentivizes high-emitting resources to retire and be replaced by lower-emitting resources.
>
> However, electricity markets on their own will not necessarily achieve emissions reductions in the absence of a market-based carbon policy. If no carbon pricing exists or carbon prices are too low to achieve the desired level of emissions reductions, then the wholesale electricity market will simply minimize other costs without fully considering the public policy value of avoiding carbon emissions.[1]

[1] Brattle Group, *The Future of Ontario's Electricity Market: A Benefits Case Assessment of the Market Renewal Project*, prepared for the IESO, April 20, 2017.

Questions:

(a) Please describe the extent to which this goal will be achieved in the current iteration of MRP.

(b) Please describe any aspects of MRP as conceived at the time of the Brattle Group report that would allow markets to reduce carbon emissions in the lowest-cost manner that are no longer being pursued in the current iteration of MRP.

(c) If a policy decision were made in the future to decarbonize electricity by 2030, how would MRP contribute to achieving that policy, if at all?

(d) Please describe in detail how carbon prices are incorporated in the prices of different resource options (if at all) and the IESO's expectations on how carbon prices will be incorporated in 2025 and 2030?

RESPONSE

(a) Please note that the 2017 MRP Benefits Case "Brattle Group Report" was an initial study to confirm directionally that MRP would provide sufficient benefits and to guide the IESO to pursue a more formal business case. The subsequent 2019 MRP Business Case is more relevant given it used information specific to Ontario as inputs for the financial assessment of benefits. The IESO also notes that the OEB's Decision in EB-2019-0002 ordered the IESO to include the MRP Business Case within this filing, which has been done. See response to Schedule 6 - 4.0 ED 10.

(b) See response to (a)

(c) As noted in Procedural Order No. 1, the IESO's application is based on a business plan that has been reviewed and approved by the Minister of Energy and the review of the IESO's application should be focused on the IESO's OM&A and capital expenditures. The IESO's revenue requirement submission is not a proceeding to consider market design investments and incorporation of policy initiatives within MRP. Further, the IESO has not re-estimated benefits included in the MRP Business Case as there is no provincial policy that is mandating phasing out of gas-fired power generation. This scenario was also not within scope of the MRP Business Case.

(d) It is up to the Market Participants if they choose to incorporate carbon costs into their offers.

ED INTERROGATORY 13

Issue 4.0 Market Renewal Program (MRP)

Interrogatory # 4.0-ED-13

INTERROGATORY

Reference: Exhibit G-2-1, Attachment 1

Preamble: According to a report published by the Ontario Clean Air Alliance:

"1. EV batteries with bi-directional chargers are cheaper than gas plants for peak power

2. EVs are an enormous opportunity to lower electricity rates & carbon emissions

3. By 2030, EVs will have more than twice the capacity of Ontario's gas plants

4. When all cars are electric, their gross discharge capacity (GW) will be more than 6 times Ontario's total peak demand

5. Technical barriers to bi-directional charging have largely disappeared (with more bi-directional-capable cars and chargers and million+ mile batteries)"[1]

Questions:

a. How will MRP impact the cost-effectiveness or potential for vehicle-to-building integrations that offset building loads at the time of peak demand with a car's battery, if at all?

b. How will MRP impact the cost-effectiveness or potential for vehicle-to-grid integrations that offset grid loads at the time of peak demand with a car's battery, if at all?

c. Can customers or third-party aggregators providing peak demand reductions through vehicle-to-building technology participate in current or future IESO capacity auctions? If not, when is that expected to be available?

d. Can customers or third-party aggregators providing peak power through vehicle-to-grid technology participate in current or future IESO capacity auctions? If not, when is that expected to be available?

e. When are the next IESO capacity auctions scheduled for and how much capacity will be procured in each?

f. Has the IESO worked with Peak Power or other providers of vehicle-to-grid/building technology to ensure the removal of market barriers for the provision of capacity, peak energy, and other services through V2X?

[1] https://www.cleanairalliance.org/wp-content/uploads/2021/08/Vehicle-to-Building-and-Grid-for-Peak-Needs-August-3-2021.pdf.

RESPONSE

a. This is outside the scope of the Market Renewal Program (MRP). The IESO is currently undertaking an Enabling Resources Program that will produce an integrated plan outlining the sequencing, timing and scope of activities to be undertaken by the IESO to enable existing electricity resources to provide electricity system services in the renewed Ontario wholesale market that they cannot, or cannot fully, currently provide. Information on the engagement is available at: https://ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Enabling-Resources-Program.

b. See response to a).

c. Third party aggregators can participate in the capacity auction as virtual hourly demand response resources. The IESO does not stipulate which technologies are eligible to be used behind a customer's load meter in order to provide the demand response, however, the demand response resource must be compliant with the Market Rules in order to participate.

d. Third party aggregators can participate in the capacity auction as virtual hourly demand response resources. The IESO does not stipulate which technologies are eligible to be used behind a customer's load meter in order to provide the demand response, however, the demand response resource must be compliant with the Market Rules in order to participate. Please also note that resources that inject behind-the-meter of a load are considered to be providing demand response through load displacement (i.e., behind-the-meter resources cannot participate directly in the wholesale market, they must participate through the load behind which they are embedded. Future procurements will outline the need that will be procured and what the eligible resources would be.

e. Auctions are held annually every December. Pre-auction reports indicating target capacities and related information are issued every September. The IESO's 2021 Annual Acquisition Report (AAR) also includes forwad looking inormation with regard to potential future capacity needs. The AAR is available at: https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Acquisition-Report

f. Through its Grid Innovation Fund (GIF), the IESO has funded a number of projects related to vehicle-to-grid (V2G) technologies. These grid innovation projects gather data on the viability and scalability of V2G to provide grid level services. This includes demonstrating technical integration, performance of the assets through distributed energy resource (DER) test cases, and evaluating both project and long-term market effects. It should be noted that the GIF projects are funded through Global Adjustment and not through IESO regulated fees. The following is a list of projects funded through the GIF related to V2G:

Lead Proponent	Project Name	Project Description
Alectra Utilities	Alectra @ Work	Alectra seeks to assess the role that smart electric vehicles charging at workplaces can play in Ontario's electricity system. It will do so by conducting a real-world implementation of a smart charging solution, and analyzing the business and technical considerations that would make this an economical service for utilities and service providers to offer in the Ontario market.
Alectra Utilities	Alectra Drive @ Home	Alectra seeks to develop and implement an electric vehicle (EV) deployment model for residential customers to identify the economic, technical, regulatory and customer outreach considerations that will be relevant to deploy these solutions at scale in the future to benefit the local and provincial electricity system. Participants will pay a monthly fee for access to electricity vehicle supply equipment (EVSE) i.e., charging station provided by Alectra and will pay for use of the station according to time-varying rates designed to encourage vehicle shifting during off-peak periods, while also being subject to demand response events that respect customer needs.
Elocity Technologies Inc.	HIEV – A digital platform for Local Distribution Companies ("LDCs") to Manage Grid Reliability and Enable Smart EV ("EV") Charging.	Elocity proposes to demonstrate the value of an interoperable, secure, scalable digital platform (Hyper Integrated EVs - HIEV) with two LDCs (Toronto Hydro and Waterloo North Hydro). The HIEV hardware and software will be used to monitor, manage and control residential EV charging load within the distribution network. HIEV enables grid-friendly EV charging infrastructure management. The benefit to EV owners is the ability to secure utility incentives, while enabling ratepayer benefits through improved grid capacity utilization.
Essex Powerlines Corporation	DER & EV Visibility Tool	This project will enable clear visibility to EVs and DERs and their impacts on distribution system assets by giving detailed data that will allow for better planning, operation, and integration of distributed energy resources. The detection tool will be an integrated software that helps manage and promote customer

Lead Proponent	Project Name	Project Description
		trends in electrification and conservation in a cost-effective manner.
Peak Power Inc.	V2H for Improved Reliability and IAM Participatio n	Peak intends to partner with Hydro One Networks Inc. (HONI) to demonstrate the feasibility and cost-effectiveness of Vehicle-to-Home (V2H) technology for two distinct use cases – improving reliability for residential customers by providing back-up power during outages, and modelling participation in IESO Administered Markets (IAMs) when the vehicle is connected, and it benefits the grid to do so.
Plug'n Drive Coalition of Ontario	Charge My Car Project	The purpose of the project is to advance EV uptake, education, visibility and reporting to benefit LDCs and Ratepayers. Plug'n Drive (PND) will hire/second a short term (one-year) resource to be its internal/external champion and evolve the program to ensure the short- term objectives are met and long term strategies developed. PND will maintain and evolve their specialized product (EV charging station store) and will maintain and grow their exclusive partnerships with LDCs for EV data sharing and reporting.
Sky Clean Energy, LTD	Optimal Vehicle to Grid Charging System Considering Solar, Storage, and User Privacy	This project demonstrates a public-facing, V2G charging system that enables EV owners to participate in demand response events (DR) while aggregated with other on-site DERs. The project will: 1) Design a control algorithm that reduces peak demand while respecting EV owner preferences; 2) Implement a data privacy protection algorithm to prevent the unauthorized disclosure of EV owner data using distributed ledger technology (DLT); and 3) Perform a V2G incentive feasibility analysis for the LDC partner, which aims to develop an incentive structure for potential roll-out to the broader Ontario energy sector.
SWTCH E-Car Inc.	Enhancing grid efficiency through a blockchain-based EV charging	SWTCH E-Car Inc. is proposing a project with the objective of addressing the challenge of increased energy demand and its impact on distribution networks from localized, high-density deployments of EVSE through DER aggregation and DR integration using an efficient and scalable blockchain platform for EV charging management that materially enhances grid efficiency.

Lead Proponent	Project Name	Project Description
	and DER aggregation platform	SWTCH will implement of IESO'S Standardized DER Test Cases for Demand Response, Operating Reserve, Regulation Service, and Target Ramp to assess performance of the platform and resources in providing grid services.
York University	Impacts of Adopting Full Battery-Based Electric Transit Bus Systems on Ontario Electricity Grid	In this project, the smart grid research team at York University will develop the engineering tools, i.e., modeling, simulation, design, and optimization, required for studying the impacts of adopting full battery-based electric city and school buses on utility grids. In collaboration with the project industry partners, the developed tools will be utilized to: 1) quantify the impacts of implementing electric bus systems on local distribution networks and bulk electricity systems, and 2) identify and evaluate the potential energy conservation barriers and technical best practices for efficient electrification of transit bus fleets in Ontario.

The IESO is also studying the potential of V2G technology through the DER Potential Study to better understand how DERs are likely to emerge or become economic, the services they can provide to the grid, and recommendations for integration into the bulk system.

Page Intentionally Blank

ED INTERROGATORY 14

Issue 4.0 Market Renewal Program (MRP)

Interrogatory # 4.0-ED-14

INTERROGATORY

Interrogatory # 4.0-ED-1

Reference: Exhibit G-2-1, Attachment 1

Preamble: The Brattle Group report states as follows on page vi states:

> "As shown, we estimate that Market Renewal will produce benefits with a present value of approximately $510 million from energy market reforms, $580 million from operability reforms, and $2,530 million from capacity auction reforms."[1]

Questions:

(a) Is it correct to say that the "energy market reforms" and "operability reforms" are being pursued in the current iteration of MRP before the OEB in this proceeding?

(b) Has the IESO already implemented some or all of the capacity auction reforms as described in the Brattle Group report? If yes, please list which are and are not being implemented.

(c) In light of the large benefits to the capacity market reforms indicated in the Brattle Group report, please describe each capacity market reform that is not being pursued and explain why.

RESPONSE

(a) Energy market reforms are being pursued in the current iteration of the MRP. The expected benefits will span the sector, enabling the IESO to realize significant improvements, reduce costs for market participants, address known inefficiencies, and establish a robust market to integrate emerging and new technologies. Operability reforms are not pursued in the current iteration.

(b) No. The IESO made the decision not to move forward with the Incremental Capacity Auction as proposed; as a result, the descriptions in this report are no longer directly applicable. Instead, the IESO has developed a Resource Adequacy Framework. Within

[1] Brattle Group, *The Future of Ontario's Electricity Market: A Benefits Case Assessment of the Market Renewal Project*, prepared for the IESO, April 20, 2017.

that framework, the IESO will continue to evolve and expand participation to enable the Capacity Auction to serve as a balancing mechanism to meet short-term needs.

(c) Please see response to (b).

ED INTERROGATORY 15

Issue 4.0 Market Renewal Program (MRP)

Interrogatory # 4.0-ED-15

INTERROGATORY

Reference: Exhibit G-2-1, Attachment 1, Page 11

Preamble: "The new design will ensure a greater share of system costs are reflected in market prices, eliminating the need for most out-of-market payments."

These questions will help to explain the challenges that MRP is attempting to resolve. For the answers to the below questions, the IESO may wish to focus on a recent representative year, such as 2018 or 2019 (which are pre-pandemic).

Questions:

(a) What share of supply costs are currently reflected in market prices? Please provide a detailed answer, including appropriate references to the Global Adjustment ("GA") and Hourly Ontario Electricity Price ("HOEP").

(b) When the IESO refers to costs being reflected outside of market prices, are these costs reflected in the GA, either wholly or partially? If only partially, what percent of these costs are reflected in the GA versus elsewhere, and where else are those costs reflected?

(c) Please describe at a qualitative level the percent of energy costs that are reflected outside of market prices (i.e. outside of HOEP). Please also estimate the approximate percent of energy costs reflected outside of market prices (i.e. outside of HOEP).

(d) Please describe at a qualitative level the percent of operating costs that are reflected outside of market prices (i.e. outside of HOEP). Please also estimate the approximate percent of operating costs reflected outside of market prices (i.e. outside of HOEP).

(e) Please complete this table to the best of the IESO's ability, making and stating assumptions, simplifications, and caveats as necessary:

Breakdown of Total Electricity Supply Costs				
	Operating costs	Capital costs	Return/profit	Total
% reflected in HOEP				100%
% reflected in GA				100%
% elsewhere				100%

Total	100%	100%	100%	

(f) Please complete this table to the best of the IESO's ability, making and stating assumptions, simplifications, and caveats as necessary:

Breakdown of Total Electricity Supply Costs			
	Energy costs	Capacity costs	Total
% reflected in HOEP			100%
% reflected in GA			100%
% elsewhere			100%
Total	100%	100%	

RESPONSE

(a) As noted in Procedural Order No. 1, the IESO's application is based on a business plan that has been reviewed and approved by the Minister of Energy and the review of the IESO's application should be focused on the IESO's OM&A and capital expenditures. The IESO's revenue requirement submission is not a proceeding to consider market design investments or analyze historical wholesale market outcomes. Further, this calculation would require a large set of detailed data and could not reasonably be completed within the time allowed for interrogatories. Additionally, this calculation was not necessary for the MRP Business Case assessment as the benefits were calculated based on reducing inefficiencies of the current energy market only.

(b) The IESO's website provides public data sets on HOEP, Global Adjustment and Supplier output and interested parties can avail themselves of this information[1]:

(c) These would include out-of-market uplifts and Global Adjustment.

(d) Please see response to (a).

(e) Please see response to (a).

(f) Please see response to (a).

(g) Please see response to (a).

[1] https://www.ieso.ca/en/Power-Data/Price-Overview/Global-Adjustment

ED INTERROGATORY 16

Issue 4.0 Market Renewal Program (MRP)

Interrogatory # 4.0-ED-16

INTERROGATORY

Reference: Exhibit G-2-1, Attachment 1, Page 11

Preamble: "The new design will ensure a greater share of system costs are reflected in market prices, eliminating the need for most out-of-market payments."

Questions:

(a) Currently, what share of system costs are reflected in market prices?

(b) After MRP is completed (e.g. in 2030), approximately what share of system costs will be reflected in market prices.

To address future uncertainties, please make and state assumptions, simplifications, and caveats as necessary.

RESPONSE

(a) See response to Schedule 6 - 4.0 ED 8 and 4.0 ED 15.

(b) See response to a).

Page Intentionally Blank

ED INTERROGATORY 17

Issue 4.0 Market Renewal Program (MRP)

Interrogatory # 4.0-ED-17

INTERROGATORY

Reference: Exhibit G, Tab 2, Schedule 1, Plus Attachment(s), Page 1

Preamble:

> "MRP high level design began with two streams: the energy stream and the capacity stream (known as the Incremental Capacity Auction (ICA)). In July 2019, further work on the ICA portion of the program was stopped as a result of updated planning assumptions and in response to stakeholder feedback."

Questions:

(a) Please describe in detail the updated planning assumptions that resulted in the stoppage of the ICA portion of the program. Please include the specific data points with respect to the updated assumptions. Please also describe how the assumptions resulted in the stoppage.

(b) Please describe in detail the stakeholder feedback that resulted in the stoppage of the ICA portion of the program. Please summarize the feedback and attribute each item to the specific stakeholder or stakeholder type (e.g. generator, customer, LDC, etc.).

RESPONSE

a) The rationale for why the IESO ceased to move forward with the ICA was included in EB-2019-0002, Exhibit C-2-2, Pages 1 and 2. In general, the IESO ceased to move forward with the ICA due to updates to the IESO's planning outlook made at the time that indicated sufficient energy supply to meet demand and a limited need for additional capacity if existing resources were reacquired when their contracts expired. These capacity needs were deemed to be able to be met through existing and available resources.

   Please note that the IESO's 2020 and 2021 Revenue Requirement Submissions do not include spending related to the ICA.

b) See response to a). In general, stakeholders felt the IESO should have considered alternative options to the ICA, while others felt the ICA did not provide sufficient investment certainty to commit to multi-year construction of new resources. Stakeholder feedback on the ICA, including engagement summaries, are available on https://www.ieso.ca/en/Market-Renewal/Stakeholder-Engagements/Market-Renewal-

Incremental-Capacity-Auction. Please note that requests for specific materials will need to be submitted to engagement@ieso.ca.

Please note that the IESO's 2020 and 2021 Revenue Requirement Submissions do not include spending related to the ICA.

ED INTERROGATORY 18

Issue 4.0 Market Renewal Program (MRP)

Interrogatory # 4.0-ED-18

INTERROGATORY

Reference: Exhibit G-2-1, Attachment 1, Page 13

Preamble:

> "The Single Schedule Market design changes will ensure that costs are transparently reflected in price thereby enabling resources, including new technologies such as energy storage and demand response, to more actively participate in the market and make more informed decisions when supplying and withdrawing energy."

Questions:

(a) Please elaborate on how MRP will allow storage and demand response to more actively participate in the market.

RESPONSE

(a) The Enhanced Real-Time Unit Commitment (ERUC) initiative will create a level playing field for all resource types through three-part offers which will include energy, start-up and speed-no-load costs thus increasing transparency and competition within the commitment process.

The IESO is currently undertaking an Enabling Resources Program that will produce an integrated plan outlining the sequencing, timing and scope of activities to be undertaken by the IESO to enable existing electricity resources to provide electricity system services in the renewed Ontario wholesale market that they cannot, or cannot fully, currently provide. Information on the engagement is available at: https://ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Enabling-Resources-Program.

Page Intentionally Blank

ED INTERROGATORY 19

Issue 4.0 Market Renewal Program (MRP)

Interrogatory # 4.0-ED-19

INTERROGATORY

Reference: Exhibit G-2-1, Attachment 1, Page 33, 35

Preamble: Page 33 describes a new kind of hydro modelling. Page 35 notes that "Reduced spilling from hydro resources should also increase taxpayer revenues from hydro rental charges."

Questions:

a. Does the hydro modelling included in MRP present an opportunity to reap additional benefits from MRP?

b. Please confirm that hydro rental charges are currently treated as a variable operating cost as part of a hydro facility's Gross Revenue Charge ("GRC"). If not, please explain.

c. Please confirm that hydro facilities are currently expected to spill water when the price is below their GRC?

d. In the quote above from page 35, the IESO notes that hydro rental charges result in taxpayer revenues. Please describe how hydro rental charges are different from other variable operating costs from the perspective of society as a whole.

e. Once MRP has been implemented, could the hydro modelling be set such that hydro facilities will only spill when the price is below their variable operating costs excluding hydro rental charges?

f. Please provide a best-efforts order-of-magnitude estimate of additional hydro rental charges that might be generated if the MRP hydro modelling were to be done in accordance with (e) above.

g. What kinds of resources provide bids in the range of $0 to $14 / MWh?

h. Under the current market structure, are gas plants ever operating when a hydro facility that could serve the same load is spilling? If yes, how often and approximately for how much energy (MWh)?

RESPONSE

a. Yes, there is opportunity to gain additional benefits from improved hydro modeling. This benefit could not be reasonably and accurately quantified.

b. Hydro resource owners may choose to reflect such charges into their offers for the energy market. The IESO cannot dictate how resource owners form their offer prices.

c. It is up to the resource owner to determine how they form their offers for dispatch. If the offers are not economic in the energy market, the resource would not be scheduled.

d. Hydro resource owners may choose to reflect such charges into their offers for the energy market.

e. Resource dispatch is based on economics. The resource owner determines the offer price at which they wish to produce energy.

f. As it is very difficult to predict future market conditions and market participant behaviour, the IESO does not conduct this kind of modelling.

g. Market participants determine their offer price based on their variable costs that may vary with market conditions.

h. Resource dispatch is based on economics. Hydro resources may offer such that they are not economic relative to gas offers. Spill amounts would be known by the resource owners.

ED INTERROGATORY 20

Issue 4.0 Market Renewal Program (MRP)

Interrogatory # 4.0-ED-20

INTERROGATORY

Reference: Exhibit G-2-1, Attachment 1, Page 36

Preamble:

> "As a proxy of the inefficiency costs of today's commitment process, over 1,300 historical resource commitments were individually inspected. A re-dispatch of resources to meet demand was undertaken with each individual resource commitment removed and replaced by resources that were available and not previously scheduled. The total costs to meet demand from the re-dispatched case were compared against the total costs with the original commitment and its start-up costs. If the redispatched costs were lower, the inefficiency cost of the commitment was the difference between the two values, otherwise, the commitment was efficient."

Questions:

(a) Please provide the underlying documentation in which this comparison was made. Please also provide any internal summaries of this comparison.

(b) For the aggregate of all time periods deemed in efficient, please provide a breakdown of the (i) original commitment and (ii) the re-dispatched commitment, by MW per generator type (gas, wind, solar, nuclear, etc.).

RESPONSE

(a) The MRP Business Case focused on why changes to Ontario's energy market are required, addressing known flaws and inefficiencies, and the value of creating a new platform to enable future market improvements and evolution. The Business Case also includes an assessment of the net benefits of the energy market enhancements over the first 10 years. In 2019, the IESO engaged stakeholders on the development of the Business Case to aid understanding and build support. The IESO held five engagement sessions, including an in-depth look at the benefits. Stakeholders contributed feedback and participated in discussions into topics such as costs and risks that were factored into the MRP Business Case. The IESO Board approved the Business Case in October of 2019.

The Business Case includes the methodology for the analysis that was undertaken with regards to the inefficiency costs of today's commitment process. Further, the comparison was calculated using actual individual market participant submitted costs

and offers that are commercially sensitive. The underlying market data is not relevant to a focused review of the IESO's capital and OM&A expenditures. The quantifiable benefits are relevant, which are provided for in the Business Case, with more efficient commitments expected to save consumers approximately $190 million in MRP's first 10 years of operation.

(b) The savings calculated is the difference between the original commitment and re-dispatched commitment and were based on using actual individual market participant offers. The calculation did not distinguish which type of resources the original commitment or re-dispatched commitment came from, only that there was a lower cost offer available. The MW amounts per generator type were also not calculated as they were not necessary values required for the MRP Business Case assessment.

ED INTERROGATORY 21

Issue 4.0 Market Renewal Program (MRP)

Interrogatory # 4.0-ED-21

INTERROGATORY

Reference: Exhibit G-2-1, Attachment 1, Page 36

Preamble:

> "Resource commitment plays an important role in the electricity market as it provides time and certainty to NQS resources, such as a combined-cycle gas turbine facility, to make necessary arrangements to produce energy."

Questions:

(a) Please provide a list of which resource types are and are not NQS (gas, wind, solar, nuclear, etc.).

(b) NQS resources "can take significant time to start-up and must remain online for a minimum amount of time to avoid damaging equipment." Please provide the approximate range of start-up times and minimum operating times for the different resource types.

RESPONSE

(a) Please see the table below.

Table 1: Quickstart and Not Quickstart Resources

		Start Times		Minimum Generation Block Run Time	
	Fuel Type	**Min**	**Max**	**Min**	**Max**
Not Quickstart	**Bio Fuel**	10 minutes to 16 hrs		1 to 8 hours	
	Gas				
	Oil				
	Steam				
	Uranium				
	Other				
Quickstart	**Solar**	1 to 5 minutes		N/A	
	Water				

		Start Times		Minimum Generation Block Run Time	
	Fuel Type	**Min**	**Max**	**Min**	**Max**
	Wind				
	Other				

(b) See response to a).

ED INTERROGATORY 22

Issue 4.0 Market Renewal Program (MRP)

Interrogatory # 4.0-ED-22

INTERROGATORY

Reference: Exhibit G-2-1, Attachment 1, Page 38

Preamble:

> "The assessment indicated that on average 9% and 13% of net exports to MISO and the New York Independent System Operator respectively have been inefficient.
>
> …Projecting the inefficiency costs of net exports avoided with improved pricing at the interties, a total of approximately $285 million is expected to be saved over the first 10 years MRP is in operation."

Questions:

(a) Will the elimination of the inefficiencies described above lead to greater or lesser net exports. Please calculate the change in % and MWh. The IESO may wish to use the data from 2015 to 2018 used to calculate the inefficiencies.

(b) For the years used by the IESO to answer (a), please provide a breakdown of Ontario's energy imports and exports (MWh) by resource type and trading partner (i.e. State or Province).

(c) Will the elimination of the inefficiencies described above likely increase or decrease the gas-fired electricity consumed in Ontario? Please estimate the likely change (% and MWh).

(d) Will MRP likely result in an increase or decrease in imported gas-fired generation on an annual basis, all else equal?

RESPONSE

(a) As noted in Procedural Order No. 1, the IESO's application is based on a business plan that has been reviewed and approved by the Minister of Energy and the review of the IESO's application should be focused on the IESO's OM&A and capital expenditures. Further, modeling of the change to net exports was not necessary for the MRP Business Case assessment and was not performed.

(b) As noted in Procedural Order No. 1, the IESO's application is based on a business plan that has been reviewed and approved by the Minister of Energy and the review of the IESO's application should be focused on the IESO's OM&A and capital expenditures. Further, these calculations were not necessary for the MRP Business Case assessment as

the benefits were calculated based on reducing inefficiencies of the current energy market.

The IESO also makes available reports of the scheduled intertie imports and exports, and actual flow, on the IESO website, here: http://reports.ieso.ca/public/. The report in question is labeled, "IntertieScheduleFlow". For clarity, the IESO is unable to report on the resource type for imports as this data is not available.

(c) This type of modeling was not necessary for the MRP Business Case assessment and was not performed. See response to Schedule 6 - 4.0 ED 10.

(d) This type of modeling was not necessary for the MRP Business Case assessment and was not performed. See response to Schedule 6 - 4.0 ED 10.

ED INTERROGATORY 23

Issue 4.0 Market Renewal Program (MRP)

Interrogatory # 4.0-ED-23

INTERROGATORY

Reference: Exhibit G-2-1, Attachment 1, Page 70

Preamble:

> "For the Decentralized Future scenario, … the financial benefits from improved commitment and competition could be lower than expected as the expansion of distributed resources reduces the role of traditional generators from which these benefits are attributable."

Questions:

(a) Please provide a breakdown of what the IESO would include in the category of "traditional generators" in the above reference.

(b) Please provide an approximate breakdown of the benefits of MRP according to the resource type they are attributable consistent with the above reference.

RESPONSE

(a) For the purposes of the MRP Business Case, in assessing the Decentralized Future scenario, a distinction between specific types of resources making up "traditional generators" was not necessary and was not performed. The IESO was pointing out that for a Decentralized Future scenario, more system needs may be served by resources not connected to the IESO-controlled-grid that would not be optimized for dispatch via price signalling in the energy market.

(b) This calculation was not necessary for the MRP Business Case assessment and was not performed. Further, the MRP Business Case calculated benefits that accrue to electricity consumers and not to resources.

Page Intentionally Blank

AMPCO INTERROGATORY 19

Issue 4.1 Is the reporting on financial and operational performance of the MRP appropriate?

4.1-AMPCO-19

INTERROGATORY

Ref: Exhibit G Tab 2 Schedule 1 Page 4 Table 3

The IESO provides the annual CPI and SPI for the MRP work performed in 2019 and 2020.

a) Please provide the calculations that underpin the CPI and SPI values for 2019 and 2020.

b) Please provide the CPI and SPI results to date for 2021.

RESPONSE

a) The calculations that underpin the CPI and SPI values have been included in the table below. For 2019, annual project costs were used for SPI/CPI. For 2020 and 2021, the accumulated project costs were used for SPI/CPI.

b) The CPI and SPI results to date for 2021 have been included in the table below.

Table 1: MRP Performance Measures

Year	Earned Value (EV)	Planned Value (PV)	Actual Cost (AC)	SPI=EV/PV	CPI=EV/AC
2019	$20,517,000	$25,290,000	$12,586,000*	0.81	1.63
2020	$47,950,000	$55,789,000	$53,351,000	0.86	0.90
2021(up to July)	$83,365,000	$91,899,000	$68,657,000	0.91	1.21

* The 2019 actual cost for the CPI calculation differs from the filing actual cost of $13.4M due to financial accruals that occurred after the CPI was calculated.

Page Intentionally Blank

AMPCO INTERROGATORY 20

Issue 4.1 Is the reporting on financial and operational performance of the MRP appropriate?

4.1-AMPCO-20

INTERROGATORY

Ref: Exhibit G Tab 2 Schedule 1 Page 6

The SPI for MRP was below target due to delays associated with IT vendor contract negotiations and detailed design documents development, which impacted dependency tasks such as static testing and process design work.

a) Please discuss how the delays associated with IT vendor contract negotiations and detailed design documents development are being addressed.

b) Please discuss if these delays are an ongoing issue that could impact the schedule in 2021, 2022 and 2023.

RESPONSE

a) The IESO has established contracts with all major vendors so the risk of delays associated with IT vendor contract negotiations has been mitigated.

b) While there are future negotiations for IT vendors that may need to occur, it is not expected that any of the remaining IT vendor contracts that need to be negotiated will cause delays in future years as any remaining negotiations are expected to generally be change requests to existing contracts that are smaller in size (i.e., not major vendors) and are not on the critical path.

Page Intentionally Blank

AMPCO INTERROGATORY 21

Issue 4.1 Is the reporting on financial and operational performance of the MRP appropriate?

4.1-AMPCO-21

INTERROGATORY

Ref: Exhibit G Tab 2 Schedule 1 Page 6

With respect to Project Governance, the evidence states "Governance of the MRP is provided by the IESO Board who approve business objectives and an envelope on schedule and budget. An Executive Steering Committee (ESC), comprised of the IESO Executive Leadership Team, works within this envelope to provide strategic direction to the project team and approve scope and delivery strategy. The ESC and the project team are supported by an advisory group comprised of senior leaders throughout the organization who provide guidance and direction for the successful delivery of the program.

a) Please provide the key metrics for MRP beyond CPI and SPI that the IESO is reporting on regarding the implementation phase of the project.

b) Please provide the results for 2019 and 2020.

RESPONSE

a) In addition to SPI and CPI the IESO uses qualitative metrics on project health, adherence to business objectives, schedule and cost. Please see Schedule 14 - 4.4 SEC 22, ttachment 1, MRP Status Update, for the additional reporting metrics used for MRP.

b) The implementation phase of the project, and use of these metrics, did not begin until 2021. Please see Schedule 14 - 4.4 SEC 22, Attachment 1, MRP Status Update for the latest status update for 2021.

Page Intentionally Blank

EDA INTERROGATORY 9

Issue 4.1 Is the reporting on financial and operational performance of the MRP appropriate?

EDA Interrogatory 9

INTERROGATORY

Evidence Reference: G/2/1/p7 T4

EDA Interrogatory 9

Please restate the 2019 budget amounts to show the amount that was planned to be incurred in 2019 after the decision to delay the deployment of MRP was made and discuss whether the remainder will be incurred in a future period:

a) in the same amount

b) a lesser amount

c) a greater amount.

Please be detailed and state all assumptions.

RESPONSE

a) 2019 budgets amounts were unchanged. Decision to delay the deployment of MRP was made in 2021.

b) See response to a).

c) See response to a).

Page Intentionally Blank

EDA INTERROGATORY 10

Issue 4.4 Is the IESO's MRP Baseline Schedule and Budget for each year of the MRP appropriate?

EDA Interrogatory 10

INTERROGATORY

Evidence Reference: G/2/1/p4

Preamble

The IESO's evidence references that MRP will go live in November 2023 and that this is approximately 8 months later than the originally proposed go live date.

EDA Interrogatory 10

a) Please quantify the impact of this delay on costs to be incurred in 2021, including incremental OM&A and incremental carrying charges on MRP assets.

b) Please discuss how these incremental costs are to be recovered and the appropriateness of this proposal.

RESPONSE

a) The impact of the delay on costs to be incurred in 2021 is $8.6 million less capital spend and no change to operating spend. The IESO's 2021 proposed capital expenditure envelope in Exhibit A-1-3 includes $36.0 million for MRP.

Table 1: 2021 MRP Variance in Operating and Capital Budget

(In $ millions)	2020-2022 Business Plan (Exhibit B-1-2)	2021 Revenue Requirement Submission (see Exhibit G-2-1)	Variance
2021 Operating Budget	3.6	3.6	-
2021 Capital Budget	44.6	36.0	(8.6)

Due to the deferral of capital costs, the incremental carrying charges in 2021, or capital interest, estimated in the 2021 Revenue Requirement submission is $0.2 million lower than what was originally submitted in the 2020 – 2022 Business Plan.

Table 2: 2021 MRP Variance in Capital Budget and Carrying Costs

(In $ millions)	2020-2022 Business Plan (Exhibit B-1-2)	2021 Revenue Requirement Submission (see Exhibit G-2-1)	Variance
2021 Capital Budget	44.6	36.0	(8.6)
2021 Capital Carrying Costs (Capitalized Interest)	1.2	1.0	(0.2)

b) See response to Schedule 7 - 1.1/1.2 EDA 1b).

AMPCO INTERROGATORY 22

Issue 4.2 Are the IESO's 2020 and forecast 2021 operational costs for the MRP appropriate in the context of the scope and timing of the overall project?

4.2-AMPCO-22

INTERROGATORY

Ref: Exhibit G Tab 2 Schedule 1 Page 6

With respect to operating costs, please explain the nature of the delays in 2019 in adding resources to the program during the development of the detailed design and the resulting impact on schedule.

RESPONSE

The delay in adding a consultant during the development of detailed design resulted in $0.3 million in costs saved in 2019. This consultant was eventually determined to not be required in 2020. The delay in detailed design resulted in $1.1 million of deferred external legal counsel to support market rule amendments in 2019.

The schedule impacts as a result of these savings and deferrals have already been reflected in the updated schedule included in the 2021 Revenue Requirement Submission.

Page Intentionally Blank

APPrO INTERROGATORY 24

Issue 4.2 Is the $1,000 Application Fee for market participation appropriate?

4.2-APPrO-24

INTERROGATORY

Reference: Executive Summary Exhibit A, Tab 1, Schedule 4, Page 3 of 6, Lines 13-16

Preamble: The evidence includes an increase of $3.9 million in budgeted OM&A expenses for 2021 as compared to 2020 actual OM&A expenses.

How much of the $3.9 million increase is attributable to "market rule and manual amendments"? And how much of this is attributable to *MRP*-related manual rule and manual amendments?

RESPONSE

Of the $3.9 million increase in budgeted OM&A expenses for 2021 as compared to 2020 actual, $1.5 million is related to MRP market rule and manual amendments and there is no increase related to non-MRP market rule and manual amendments.

Page Intentionally Blank

APPrO INTERROGATORY 25

Issue 4.2 Is the $1,000 Application Fee for market participation appropriate?

4.2-APPrO-25

INTERROGATORY

Reference: Executive Summary, Exhibit A, Tab 1, Schedule 4, Page 5 of 6, lines 24-25

Preamble: The evidence provides that the implementation phase of MRP will include a significant complement of IT resources.

What is the total associated cost for these IT resources? What portion of this total cost is associated with MRP? What portion of that cost is associated with necessary system upgrades due to obsolesce?

RESPONSE

The table below shows the IT staff and associated costs.

Table 1: IT Staff and Associated Costs

Year	2021	2022	2023
IT Staff Count	24	31	23
IT Staff Cost (In $ millions)	3.9	4.9	3.6

All of the identified IT costs are associated with MRP. None of the identified costs are associated with system upgrades to due to obsolescence. System upgrades are not part of the MRP budget. The IESO plans system upgrades as part of regular technology maintenance.

Page Intentionally Blank

REASCWA INTERROGATORY 19

Issue 4.2 Are the IESO's 2020 and forecast 2021 operational costs for the MRP appropriate in the context of the scope and timing of the overall project?

4.2-REASCWA-19

INTERROGATORY

Reference: Exhibit A, Tab 1, Schedule 4, Page 5, Lines 16-18

Preamble: Lines 15 to 18 of Exhibit A, Tab 1, Schedule 4, Page 5 states "The MRP presents an opportunity to implement much needed reforms to the Ontario electricity market. The expected benefits will span the sector, enabling the IESO to realize significant operational improvements, reduce costs for market participants, address known inefficiencies, and establish a robust market to integrate emerging and new technologies." However, broader integration of emerging and new technologies (e.g., energy storage, 'hybrid' resources, DERs) is being planned for post MRP implementation (e.g., as specified within the planned timeframes to implement the ERP and HIP initiatives of the IESO). Therefore, clearer understanding is needed towards how MRP will unlock the benefits relating to how it will assist in integrating emerging and new technologies.

a) Considering that an expected benefit of the MRP is to establish a market to integrate emerging and new technologies, what components within the IESO's 2020 and forecast 2021 operational costs for the MRP will result in realizing the expected benefits of integrating emerging and new technologies (e.g., energy storage, 'hybrid' renewable generators coupled with energy storage, DERs) after the MRP has been implemented?

RESPONSE

a) There are no portions of the forecasted operational costs for 2020 and 2021 that account for this. Please see response to Schedule 4 - 4.2 REASCWA 19 with regard to MRP capital costs related to integrating emerging and new technologies.

The IESO is currently undertaking an Enabling Resources Program that will produce an integrated plan outlining the sequencing, timing and scope of activities to be undertaken by the IESO to enable existing electricity resources to provide electricity system services in the renewed Ontario wholesale market that they cannot, or cannot fully, currently provide. Information on the engagement is available at: https://ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Enabling-Resources-Program.

Page Intentionally Blank

ENERGY PROBE INTERROGATORY 13

4.2 Are the IESO's 2020 and forecast 2021 operational costs for the MRP appropriate in the context of the scope and timing of the overall project?

4.2-EP-13

INTERROGATORY

Reference: Exhibit G, Tab 2, Schedule 1, Table 4, and Table 10 Plus Attachment(s)

Please provide a schedule showing approximate FTEs and related compensation costs related to MRP 2018-20 and forecast for 2021 and 2022 and 2023.

a) Please indicate if the FTEs are permanent or temporary.

b) Please provide the costs of external resources and provide a list of major contractors and amounts disbursed in 2018-2020.

RESPONSE

a) All MRP resources are non-permanent program resources. Upon the closure of MRP, all implementation resources will return to their home positions, shared resources will be assigned to other initiatives and temporary staff will be terminated.

b) See response to Schedule 14 - 4.2 SEC 20.

Page Intentionally Blank

OSEA INTERROGATORY 7

Issue 4.2 Are the IESO's 2020 and forecast 2021 operational costs for the MRP appropriate in the context of the scope and timing of the overall project?

Issue 4.3 Are the IESO's 2020 and forecast 2021 capital costs for the MRP appropriate in the context of the scope and timing of the overall project?

OSEA IR 7, ISSUES 4.2 AND 4.3

INTERROGATORY

Reference: Exhibit E-1-2 Attachment 1 – Appendix 2-AA Capital Projects & Exhibit G-2-3 Attachment 1

Preamble: The IESO, through the Energy Storage Advisory Group (ESAG) and Energy Storage Design Project, explored options to remove barriers to energy storage in the IESO-Administered Markets.[1][2] These initiatives followed activities underway in other US electricity markets to meet the requirements of Federal Energy Regulatory Commission (FERC) Order 841 (Energy Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators). The processes concluded that barriers existed to energy storage resources and that removing barriers would be beneficial for the Ontario electricity market. The IESO has decided to not include the long-term design changes for energy storage under the MRP. For clarity, the IESO states in the Long-Term Design Vision Document that energy storage incorporation in the IESO-Administered Market will occur after MRP. OSEA is interested in understanding the IESO's estimate of costs for incorporating energy storage in MRP and the analysis IESO completed to conclude that including energy storage in MRP was not prudent at this time.

Questions:

a) Please provide the business case supporting the decision to not include enabling energy storage resources in MRP.

b) Please provide any implementation cost estimates for incorporating energy storage resources into MRP, i.e., implementation cost estimates for IT (additional costs of including energy storage resources in the IT hardware and software spending for MRP system upgrades), training, testing, creation of internal protocols and manuals, capital infrastructure, and plant and equipment investments.

---

[1] Removing Obstacles for Storage Resources in Ontario (https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/esag/Removing-Obstacles-for-Storage-Resources-in-Ontario_20181219.ashx)

[2] Energy Storage Design Project (https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/esag/esag-20200915-long-term-design-vision.ashx)

c) Has the IESO completed an analysis on the value of energy storage benefits to the IESO-Administered Markets if incorporated under MRP? For clarity, value is dollar amount savings or reduced costs to electricity rate-payers from removing barriers to energy storage resources. If yes, please provide the analysis.

RESPONSE

a) Storage is currently enabled to participate in the IESO-administered markets and that will continue post- MRP. In January 2021, the Market Rules were amended such that storage is reflected in the IESO's market rules and manuals and is enabled to provide capacity, energy and operating reserve.

As part of the IESO's Storage Design Project (SDP) a number of potential future enhancements were identified for energy storage. These enhancements were captured in the SDP's long-term storage design vision. In May 2020, the IESO made a determination that the long-term storage design would not be included within the scope of the MRP.

A business case was not developed for this decision. Rather, the key driver for the decision was the risk that a material expansion in scope would pose to MRP timelines, costs, and benefits. Given that the IESO continues to target an in-service date of 2023, including storage integration within MRP would adversely impact the IESO's ability to meet that timeline and heighten the risk of increased costs and deferred benefits.

b) As noted in the response to a) above, energy storage is incorporated in the IESO-Administered Markets today and will continue to be under MRP. The costs, benefits and appropriate timing of future storage enhancements will be considered within the projects captured in the IESO's Enabling Resources Program which is currently under development.

c) See response to b) above.

SEC INTERROGATORY 20

Issue 4.2 Are the IESO's 2020 and forecast 2021 operational costs for the MRP appropriate in the context of the scope and timing of the overall project?

4.2-SEC-20

INTERROGATORY

[EB-2019-0002, Exhibit I, Tab 6.1, Schedule 10.22 SEC 22, Attachment 1] With respect to the Market Renewal Program, in the same format as provided in EB-2019-0002, please provide a similar table showing a breakdown of all MRP related Professional & Consulting Costs for each of 2020 and 2021, describing the: a) the name of the professional/consultant, b) cost of services, c) description of specific service provided, and d) method of procurement.

RESPONSE

The table below shows a breakdown of all MRP major contractors for each of 2020 and 2021, describing the: a) name of the major contractor, b) cost of services, c) description of specific service provided, and d) method of procurement.

Table 1: MRP Major Contracts for 2020 and 2021

Major Contractor	Services Provided	Procurement Type	2018 Actual	2019 Actual	2020 Actual	2021 Budget
Operating Expenses						
The Brattle Group	Consultant support for high level design	Competitive	0.3	0.3	-	-
FTI Consulting	Consultant support for high level design	Competitive	0.7	0.3	-	-
Charles River Associates	Review of MRPs impact on existing supply contracts	Competitive	0.4	0.1	-	0.2
Stikeman Elliott LLP	Legal support for market rule amendments	Competitive	-	-	0.4	0.7
Hunton Andrews Kurth LLP	Legal support for designs, supply contract inputs & governance	Competitive	0.2	-	-	-
Stikeman Elliott LLP	Legal support for designs, supply contract inputs & governance	Competitive	0.1	0.1	-	-
Torys LLP	Legal support for designs, supply contract inputs & governance	Competitive	0.3	-	-	-

Major Contractor	Services Provided	Procurement Type	2018 Actual	2019 Actual	2020 Actual	2021 Budget
Capital Expenses						
FTI Consulting	Consultant support for detailed design	Competitive	-	0.5	0.3	0.1
The Brattle Group	Consultant support for detailed design	Competitive	-	0.1	0.3	-
Hatch Ltd	Engineering Study Consultations	Competitive	-	-	0.3	0.4
EMS GROUP NA, LLC	Design Integration Support	Non-Competitive	0.1	0.5	0.4	0.5
SMCS LLC	Technical Integration Support	Non-Competitive	0.1	0.6	0.4	0.5
Paul Gribik Consulting LLC	Consultant support for optimization expertise	Competitive	-	-	0.3	0.3
Stoneman Consulting	Consultant hired for program delivery	Competitive	-	0.1	0.2	-
Gartner Consulting	Readiness Audit Vendor	Competitive	-	-	-	0.4
Kaihen Inc	Control Room Specialist	Competitive	-	-	-	0.4
Torys LLP	Legal support for designs, supply contract inputs & governance	Competitive	-	0.4	0.3	0.2
Stikeman Elliott LLP	Legal support for designs, supply contract inputs & governance	Competitive	-	-	-	0.2
Osler, Hoskin & Harcourt LLP	Legal support for designs, supply contract inputs & governance	Competitive	-	0.2	-	0.2
Hunton Andrews Kurth LLP	Legal support for designs, supply contract inputs & governance	Competitive	-	0.1	-	-
Hitachi ABB Power Grids	Dispatch Scheduler & Optimization vendor	Competitive	-	-	10.8	10.0
Symphono	Development of market charge types	Competitive	-	-	-	1.6

1

AMPCO INTERROGATORY 23

Issue 4.3 Are the IESO's 2020 and forecast 2021 capital costs for the MRP appropriate in the context of the scope and timing of the overall project?

4.3-AMPCO-23

INTERROGATORY

Ref: Exhibit G Tab 2 Schedule 1 Page 4 Table 2

a) Please provide a breakdown and description of the Professional and Consulting capital costs for each year.

b) Please provide a breakdown and description of Operating & Administration capital costs for each year.

RESPONSE

a) Please find below the breakdown of capital Professional and Consulting budget for each year.

Table 1: Professional and Consulting Costs

(In $ millions)	2021 Budget	2022 Budget	2023 Budget
Consultants - Engineering Services for Market Power Mitigation consultations	0.4	0.5	0.4
Contract Services - Readiness Audit Vendor	0.4	0.4	-
Contract Services - Design Integration Support	0.5	0.6	0.6
Contract Services - Technical Integration Support	0.5	0.6	0.6
Contract Services - Control Room Specialist	0.4	0.2	0.2
Contract Services - Ontario Market Expertise	0.3	0.4	0.3
Contract Services - Optimization Expertise	0.3	0.4	0.3
Contract Services - Generator Operator Expertise	0.2	0.4	0.3
Contract Services - Audit Settlements	0.2	0.4	0.3
Contract Services - Audit Dispatch Schedule & Optimization system	-	-	0.6
Legal Services	0.6	0.6	0.5
Professional & Consulting (less than $0.5M)	0.4	0.5	0.2
Total Professional & Consulting	**4.1**	**4.8**	**4.3**

b) Please find below the breakdown of Operating & Administration budget for each year.

Table 2: Operating & Administration Budget

Operating & Administration			
(In $ millions)	2021 Budget	2022 Budget	2023 Budget
IT Systems & Infrastructure	13.3	16.9	9.0
Post Production Fixes	-	-	1.0
Rent	0.8	0.8	0.7
Total Operating & Administration	**14.1**	**17.7**	**10.7**

AMPCO INTERROGATORY 24

Issue 4.3 Are the IESO's 2020 and forecast 2021 capital costs for the MRP appropriate in the context of the scope and timing of the overall project?

4.3-AMPCO-24

INTERROGATORY

Exhibit G Tab 2 Schedule 1 Page 7

With respect to capital costs, please explain the nature of the delays in 2019 in onboarding detailed design external support and the impact on the schedule.

RESPONSE

The delay with onboarding an external consultant to assist with detailed design in early 2019 was due to the delay in completing the detailed design itself. In 2020 it was determined that this external consultant would no longer be required. Detailed design is now complete and a delay of 8 months has been incorporated in the updated schedule included in the 2021 Revenue Requirement Submission.

Page Intentionally Blank

AMPCO INTERROGATORY 25

Issue 4.3 Are the IESO's 2020 and forecast 2021 capital costs for the MRP appropriate in the context of the scope and timing of the overall project?

4.3-AMPCO-25

INTERROGATORY

Exhibit G Tab 2 Schedule 1 Page 8

In 2020, capital spending was lower than planned due to the delayed onboarding of implementation resources, including the external vendor for the DSO tool development.

Please explain the reasons for the delays and the impact on schedule and cost.

RESPONSE

The reason for the delay was extended DSO vendor negotiations, which triggered delays in onboarding the vendor and internal IT resources. The impacts on cost and schedule have been reflected in the revised schedule and budget included in the 2021 Revenue Requirement Submission.

For clarity, this resulted in an increase of $7.7 million in total budget cost and an 8-month extension. This takes into consideration updated cost estimates for the delivery of the DSO and the extended time to deliver MRP.

Page Intentionally Blank

AMPCO INTERROGATORY 26

Issue 4.3 Are the IESO's 2020 and forecast 2021 capital costs for the MRP appropriate in the context of the scope and timing of the overall project?

4.3-AMPCO-26

INTERROGATORY

Exhibit G Tab 2 Schedule 1 Page 7

OPG identifies a change in the payment structure for the Dispatch Scheduling Optimization (DSO) procurement which moved a $10 million upfront payment budgeted for 2019 into smaller milestone payments starting in 2020.

a. Please explain why the DSO payment in 2019 was adjusted.

b. Please provide the 2020 milestone payment for the DSO and the new schedule of smaller payments going forward.

RESPONSE

a. The original planning assumption in the budget was that the DSO would require an upfront payment of $10.0 million, this estimate was made before the vendor was procured. After the vendor was procured and the statement of work was signed, the IESO updated the forecast to reflect the negotiated milestone payments within the contract.

b. The schedule of payments, including 2020, are shown in the table below.

Milestone Date	Milestone Payment (In $ millions)
Feb 2020	0.2
Mar 2020	1.7
May 2020	0.8
Jul 2020	3.1
Aug 2020	0.8
Sep 2020	0.8
Oct 2020	1.2
Dec 2020	2.1
Feb 2021	3.5
Mar 2021	1.6
Aug 2021	3.2
Nov 2021	1.6
Jan 2022	2.0
Jul 2022	4.7
Oct 2022	1.9
Dec 2022	1.5
Apr 2023	1.5
Aug 2023	1.5
Sep 2023	0.2
Oct 2023	0.2
Nov 2023	3.4

REASCWA INTERROGATORY 20

Issue 4.3 Are the IESO's 2020 and forecast 2021 capital costs for the MRP appropriate in the context of the scope and timing of the overall project?

4.3-REASCWA-20

INTERROGATORY

Reference: Exhibit A, Tab 1, Schedule 4, Page 5, Lines 16-18

a) Considering that an expected benefit of the MRP is to establish a market to integrate emerging and new technologies, what components within the IESO's 2020 and forecast 2021 capital costs for the MRP will result in realizing the expected benefits of integrating emerging and new technologies (e.g., energy storage, 'hybrid' renewable generators coupled with energy storage, DERs) after the MRP has been implemented?

RESPONSE

a) Based on MRP project forecasts for the year 2021, the MRP project anticipates spending $1.65 million in capital costs for modeling improvements and implementation efforts related to supporting emerging and new technologies.

Page Intentionally Blank

ENERGY PROBE INTERROGATORY 12

4.3 Are the IESO's 2020 and forecast 2021 capital costs for the MRP appropriate in the context of the scope and timing of the overall project?

4.3-EP-12

INTERROGATORY

Reference: Exhibit G, Tab 2, Schedule 1, Plus Attachment(s)- Market Renewal Program

Preamble: "In March 2021, the IESO Board approved a revised budget and schedule, including a new go live date of November 2023 with six months of contingency. This baseline schedule incorporates lessons learned from the high-level and detailed-design phases of the project, makes best use of existing resources, while delivering a high-quality program."

a) Please confirm the revised MRP capital and operating cost estimate and go live dates.

b) Please provide the 2021 YTD Capital Expense.

c) Will there be capital and operating costs in 2023? If so please provide an estimate.

d) Please provide the updated/most recent Benefits Realization Report. Compare this to the prior version(s).

e) Confirm the MRP without the Capacity Auction Option will produce a net benefit of $290 million (Business Case Table 9.1).

RESPONSE

a) Based on the updated cost and schedule:

- Total MRP program costs are estimated at $177.7 million
- Total MRP capital costs are estimated at $148.3 million
- Total MRP operating costs are estimated at $29.4 million
- The new go live date is November 2023 with six months of contingency

This information is presented in chart form in Exhibit G-2-1, Table 1.

b) MRP capital results for the year to date as of July, 2021 are as follows:

Table 1: MRP Capital Results YTD

(In $ millions)	2021 July Actual
Compensation & Benefits	6.6
Professional & Consulting	0.9
Operating & Administration	5.9
Interest	0.3
Contingency	-
Total Capital Expenses	**13.7**

c) Yes, the capital budget estimate is $33.8 million and the operating budget is estimated at $3.9 million.

d) There is not an updated MRP Business Case. The revised budget and schedule will not impact the program's scope. The change in schedule is not expected to have a significant impact on the project's expected benefits – the primary impact will be a short delay before benefits realization. The program will bring approximately $800 million in net benefits over a 10-year period.

e) MRP will bring approximately $800 million in net benefits over a 10-year period.

ENERGY PROBE INTERROGATORY 14

4.3 Are the IESO's 2020 and forecast 2021 capita costs for the MRP appropriate in the context of the scope and timing of the overall project?

4.3-EP-14

INTERROGATORY

Reference: Exhibit G, Tab 2, Schedule 1, Attachment 1, Table 4.1 MRP Energy Stream Contingency Breakdown

a. Why is the Cost and Contingency for IT so high?

b. How many MRP contracts for IT does IESO have? Please provide a list of major contracts and costs.

c. Why cannot IESO control IT procurement to a contingency of 10% of contract costs and NOT require a 23% Contingency? Please discuss and provide further details on contingency used to date.

RESPONSE

a. The IESO did not have complete information on the potential costs or timing that would be required to complete the successful integration with market participants at the time the MRP Business Case was developed.

b. The IESO has 10 vendors that it manages through contracts, Vendors of Record (VOR) etc. There are three core vendors that are utilized on MRP – Hitachi ABB Power Grids (~$40 M), First Derivatives (~$2.5 M), Accenture (~$2 M).

c. Contingency was based on a reasonable amount of time and budget required to mitigate risk events that were most likely to occur given the level of uncertainty of when the business case was approved. To date, the IESO has used $6 million of the contingency by allocating this amount to the program budget. Through the schedule and budget update exercise which resulted in the schedule and budget included in the 2021 Revenue Requirement Submission, the IESO expanded the program budget envelope from $170M ($154M + $16M contingency) to $177.7M ($167.7M + $10M contingency).

Page Intentionally Blank

OSEA INTERROGATORY 6

Issue 4.3 Are the IESO's 2020 and forecast 2021 capital costs for the MRP appropriate in the context of the scope and timing of the overall project?

OSEA IR 6, ISSUE 4.3

INTERROGATORY

Reference: Exhibit E-1-2 Attachment 1 – Appendix 2-AA Capital Projects; Table 2 of Exhibit G-2-1, Page 5 of 10; Exhibit G-2-1, Attachment 1

Preamble: Over 50% of the projected spending for MRP in 2021 is expected to be capital costs. Table 2 in Exhibit G-2-1 provides a breakdown of MRP by administrative cost components but does not provide a breakdown by MRP workstream categories (e.g., Day-Ahead Market, Single Schedule Market, Enhanced Real-Time Unit Commitment, etc.). Further information on the breakdown of MRP capital spending is needed to understand the priorities and potential risks of delay or overages.

Questions:

a) The IESO MRP Business Case estimates IT costs to be $53M.[1] Please provide a breakdown of the MRP capital spending by phase or component from 2021 to the 2023 implementation date for the implementation phase of MRP. Please provide sub-categories of capital spending if available, e.g., IT, training, testing, creation of internal protocols and manuals, capital infrastructure, and plant and equipment investments.

b) Please provide the IESO's contingency and reserve funding estimates related to MRP cost overruns or delays.

c) The implementation costs of the Interim Market Rules and Manuals for Energy Storage under the MRP are unclear. Please provide capital and O&M forecasts for incorporating the Interim Market Rules and Manuals for Energy Storage under MRP capital and O&M programs. Please provide any supporting documentation supporting the forecasted estimates.

RESPONSE

a) Based on the updated schedule and cost, IT related expenses from 2021 to 2023 are in the table below:

[1] Figure 4-9: MRP Energy Stream IT – Exhibit G-2-1, Attachment 1, Page 57 of 82.

Table 1: IT Related Expenses

(In $ millions)	2021 Budget	2022 Budget	2023 Budget
IT Development Staff	3.1	3.9	2.6
IT Testing Staff	0.8	1.1	1.0
IT Systems & Infrastructure	13.3	16.9	9.0
Post Production Fixes	-	-	1.0
Total IT Costs	**17.2**	**21.8**	**13.6**

b) Based on the updated schedule and cost included in the 2021 Revenue Requirement Submission, MRP has allocated $10.0 million in program contingency and 6 months of schedule contingency.

c) The effort required to align MRP Rules and Manuals with the interim storage Rules and Manuals that came into effect in January 2021 is not distinct from the overall effort required to align the MRP Rules and Manuals with the rest of the baseline Market Rules and Manuals currently in effect.

AMPCO INTERROGATORY 27

Issue 4.4 Is the IESO's MRP Baseline Schedule and Budget for each year of the MRP appropriate?

4.4-AMPCO-27

INTERROGATORY

Ref: Exhibit G Tab 2 Schedule 1 Page 3

In March 2021, the IESO Board approved a revised budget and schedule, including a new go live date of November 2023 with six months of contingency. This baseline schedule incorporates lessons learned from the high-level and detailed-design phases of the project, makes best use of existing resources, while delivering a high-quality program.

a) Please summarize the lessons learned from the high-level and detailed-design phases and how they have been incorporated in the baseline schedule.

b) Please explain how the six months of schedule contingency was determined.

RESPONSE

a) MRP is focused on continuous improvement and incorporating lessons learned from the high-level and detailed design phases to ensure the schedule for the remaining years of the project reflects the most accurate information and best practices. See response to Schedule 2 - 4.0 AMPCO 14.

b) Six months of contingency was based on a reasonable amount of time required to mitigate risk events that were most likely to occur given the level of uncertainty when the MRP Business Case was approved. When the project schedule was revised in March 2021, the contingency was reassessed and six months of contingency was deemed to still be appropriate given the risks and level of uncertainty remaining.

Page Intentionally Blank

AMPCO INTERROGATORY 28

Issue 4.4 Is the IESO's MRP Baseline Schedule and Budget for each year of the MRP appropriate?

4.4-AMPCO-28

INTERROGATORY

Ref 1: Exhibit G Tab 2 Schedule 1 Page 3

The new go live date is an extension of eight months relative to the March 2023 go live date estimated in the MRP Business Case.

Ref 2: Exhibit G Tab 2 Schedule 1 Page 4

The new schedule is a result of a number of factors, including the need to take into account design considerations influenced by stakeholder feedback, vendor related constraints and the resulting impact on the development of Market Rules and manuals.

Please explain the vendor related constraints, and discuss the schedule contingency provided to address this issue.

RESPONSE

The vendor constraint was due to contract negotiations. The contract negotiations have been completed and a contract is now in place with the vendor. See response to Schedule 2 - 4.4 AMPCO 27 b).

Page Intentionally Blank

AMPCO INTERROGATORY 29

Issue 4.4 Is the IESO's MRP Baseline Schedule and Budget for each year of the MRP appropriate?

4.4-AMPCO-29

INTERROGATORY

Ref: Exhibit G Tab 2 Schedule 1 Attachment 2

Please advise of any new changes to the MRP Schedule.

RESPONSE

There have been no changes to the MRP schedule that is included in the 2021 Revenue Requirement Submission.

Page Intentionally Blank

REASCWA INTERROGATORY 21

Issue 4.4 Is the IESO's MRP Baseline Schedule and Budget for each year of the MRP appropriate?

4.4-REASCWA-21

INTERROGATORY

Reference: Exhibit G, Tab 2, Schedule 1, Page 3, Lines 20-23

a. What risks and contingencies have the IESO planned for within the MRP project schedule and budget relating to readiness of IAM market participants and other stakeholders?

b. What are the impacts to the MRP schedule and budget if some market participants are not ready for the planned November 2023 MRP go-live date?

c. Please provide any analysis and documents relating to a) and b) above.

RESPONSE

a. Planning is underway for the market participant readiness component of the MRP Implementation phase. The IESO will work with stakeholders through the Technical Advisory Group, and outline training and support plans to work on market participant readiness.

b. Market participant readiness is a key component for MRP go-live. The planning activities referred to in the response to a) will inform timing and any potential impacts to schedule and budget.

c. This work is underway as per a).

Page Intentionally Blank

ENERGY PROBE INTERROGATORY 15

4.4 Is the IESO's MRP Baseline Schedule and Budget for each year of the MRP appropriate?

4.4-EP-15

INTERROGATORY

Reference: Exhibit G, Tab 2, Schedule 1, Attachment 2 - MRP Implementation Schedule

a) Please provide an MRP status report and if appropriate, an update to the MRP Schedule shown in the reference.

b) What are the IESO's contingency plans if the tests reveal problems?

RESPONSE

a) There have been no changes to the MRP schedule included in the 2021 Revenue Requirement Submission. Please refer to Schedule 2 - 4.1 AMPCO 21, Attachment 1 for latest status update for 2021.

b) Defect resolution is already built into the schedule included in the 2021 Revenue Requirement Submission.

Page Intentionally Blank

SEC INTERROGATORY 21

Issue 4.4 Is the IESO's MRP Baseline Schedule and Budget for each year of the MRP appropriate?

4.4-SEC-21

INTERROGATORY

[G-2-1] With respect to MRP:

a. [p.3] Please explain the difference between the original and revised budget and schedule.

b. [p.4] Please explain why the IESO believes that the extension in the go-live will have no effect on the estimated system benefits.

c. Please provide the most recent SPI and CPI measures.

RESPONSE

a. See the Market Renewal Program Cost Report at Exhibit G -2-1, Pages 3 - 6 with regards to the new baseline schedule and budget, as well as performance reporting. These sections explain the differences between the original and revised budget and schedule.

b. The increased schedule is not expected to have a significant impact on the project's expected benefits – the primary impact will be a short delay in achieving the $800 million in net benefits to be realized over the first 10 years in service.

c. See Schedule 2 - 4.1 AMPCO 19.

Page Intentionally Blank

SEC INTERROGATORY 22

Issue 4.4 Is the IESO's MRP Baseline Schedule and Budget for each year of the MRP appropriate?

4.4-SEC-22

INTERROGATORY

[G-2-1] With respect to MRP Reporting:

a. [p.5] Please provide the most recent reporting of MRP that is made to the IESO: a) executive leadership, b) Board of Directors.

b. Please provide a copy of the most recent: a) Monthly Cost Report, b) Monthly Schedule Report, and c) Monthly Risk Report.

c. For any change described in part (b), please provide their impact on the cost and/or benefit as set out in the business case. If the IESO is unable to quantify the impact, please provide the directional impact.

RESPONSE

a) The most recent reporting on MRP to executive leadership and the IESO is provided as:

- Attachment 1, MRP Status Update;
- Attachment 2, MRP Milestones;
- Attachment 3, MRP KPIs;
- Attachment 4, MRP Strategic Risks Update, and;
- Attachment 5, MRP Update for Board of Directors.

b) See Attachment 4 in response to a).

c) The MRP Business Case used conservative assumptions to show a very positive cost benefit for ratepayers. The IESO does not expect any change in the benefits from MRP. At this point in the project the IESO also does not expect any major differences in costs from those included in the currently approved budget and contingency amount.

Page Intentionally Blank

JULY 27, 2021

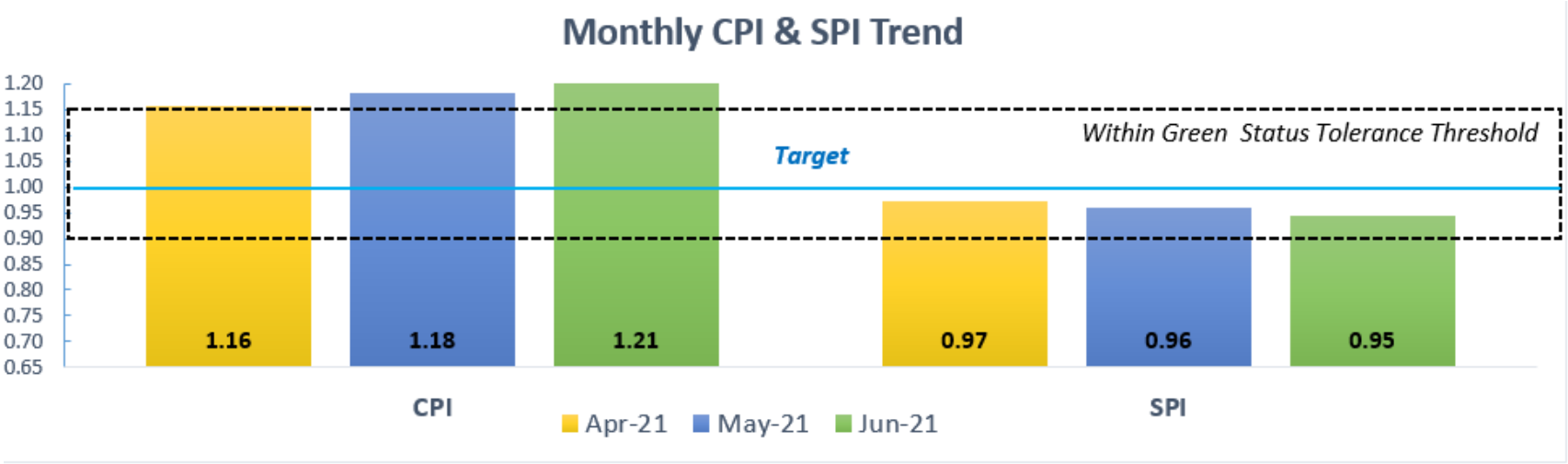
MRP Status Update: MRP-RSS Executive Steering Committee

Key Messages

Highlights and Key Messages	
Focus Area	**Description**
Key Messages	▪ The Joint Application Developments (JAD) have been delayed due to underestimating the effort required to complete the requirements gathering and the availability of key resources during the summer months. This delay, in addition to the project team working on unscheduled items (for example, Economic Operating Point), have contributed to a further reduction in SPI. To mitigate further delays the project is onboarding additional staff and updating the schedule to better reflect all known work activities on the project. ▪ Requirements stemming from the JAD sessions will likely result in the need to expand on the integration with the HAPG (ABB) solutions. This may result in the use of project budget and schedule contingency. ▪ The project has posted a Senior Integration Lead position. This new role will have a longer term focus in the project planning and will develop a plan to ensure that program deliverables of technology, data and processes are being effectively integrated into the line of business.
Project Achievements	• Preparation for publication on August 12, 2021 of Market Power Mitigation Market Rules and Manuals (Batch 2) for market participant engagement
Decisions Required	▪ N/A

Overall: Program Key Performance Indicators						
Overall Project Health	Budget Health	Cost Performance Index (CPI)	Schedule Health	Schedule Performance Index	Business Objectives	PPMLC Process Adherence
✓	✓	✓	✓	✓	✓	✓

Program Earned Value KPIs



Link to CPI/SPI details

ieso
Connecting Today. Powering Tomorrow.

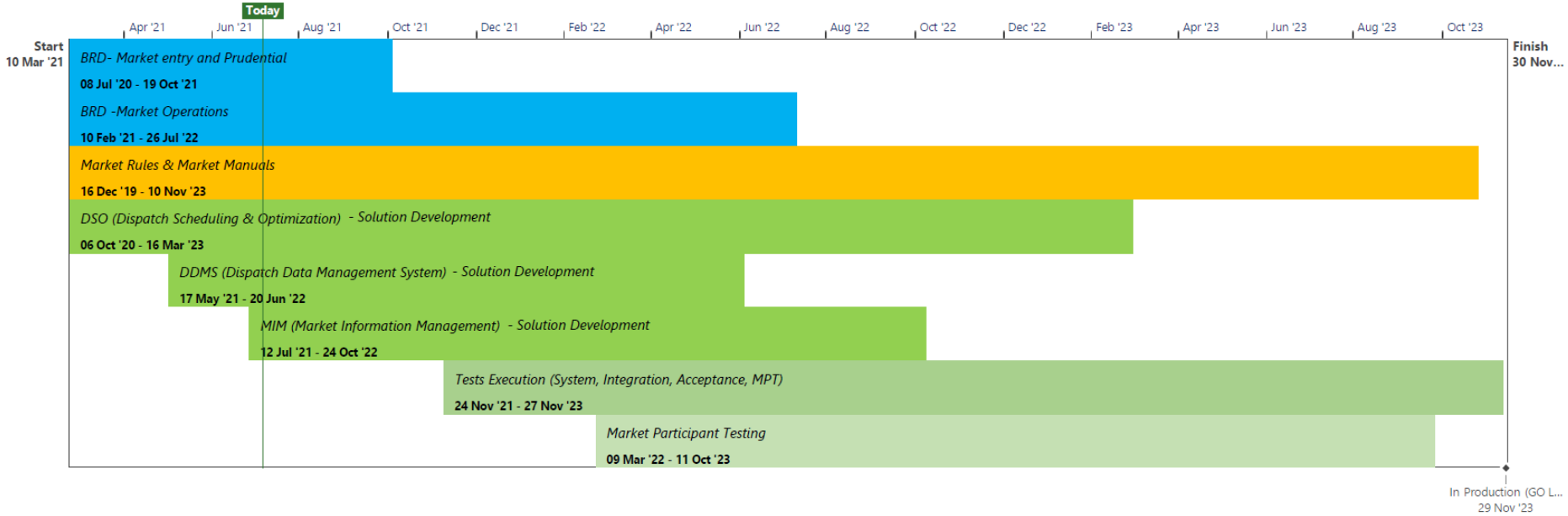
Program Financial Status

The life-to-date spend is $67 M (38%) against the Board-approved budget of $177.7M including contingency.

Financial Status						
KPI	Type	Total approved (with contingency)	Budget Contingency Available	Spend to Date (Actual Costs)	Forecast Cost at Completion	Variance to Approved Budget
✓	CapEx	$150.4 M	$10 M	$49 M	$150.4 M	$0 M
✓	OpEx	$27.3 M	$0 M	$18 M	$27.3 M	$0 M
✓	**Total**	**$177.7 M**	**$10 M**	**$67 M**	**$177.7 M**	**$0 M**

ieso
Connecting Today. Powering Tomorrow.

Schedule & Milestones (1 of 2)



ieso
Connecting Today. Powering Tomorrow.

Schedule & Milestones (2 of 2)

*Critical path is defined as 10 or less working days of slack
*Milestones listed as "N/A" under Planned Completion (Baseline 4) were added or created after the baseline was set.

Legend - Trend to Meet Forecasted Completion Date	
Ahead of Forecast Completion	Progress is anticipated to be ahead of the forecast completion date, no issues to raise
Trending to Forecast Completion	Progress is on schedule to meet the forecast completion date, no issues to raise
Potential Delay to Forecast Completion	A delay greater than 10 working days to the forecast completion date of the milestone has materialized, and mitigations are under development to correct the delay
Delay to Forecast Completion	A delay greater than 10 working days to the forecast completion date of the milestone has materialized, with no established mitigations to correct the delay

				← Past	↓ Present	↗ Trending	↗ Trending	→ Future	
ID	Schedule Subphase	Milestone	Available Slack	Planned Completion (Baseline 4)	Forecast Completion Date	Variance from Baseline (Days)	Change from Previous Forecast (Days)	Trend to Meet Forecast Completion Date	Comments
1	Requirements	MIM input JAD completed	Critical Path	N/A	13-Aug-21	N/A	NEW	Trending to Forecast Completion	MIM input JADs and MIM output JADs have been split up to allow us to advance some work for HAPG
2	Solution Development	Complete MIM Back End Development	Critical Path	5-Jul-22	24-Jun-22	-6	-4	Trending to Forecast Completion	
3	Quality Assurance	Operational tools acceptance testing completed	Critical Path	28-Sep-23	13-Oct-23	10	-1	Trending to Forecast Completion	
4	GO LIVE	In Production (GO LIVE)	Critical Path	30-Nov-23	29-Nov-23	-1	-1	Trending to Forecast Completion	

Link to detailed Critical Path Milestones

MRP Energy - Progress Report

For Reporting Period: 01/June/2021 to 30/June/2021

Milestones

Note: The Milestone Report is based on summary tasks with a Slack of less than 60 days, critical deliverables, key dates to start an activity and other items at the request of the Steering Committees. Milestones listed as "N/A" under Planned Completion (Baseline 4) were added or created after the baseline was set.
"Previous Forecast" is the Forecast Completion Date included within last month's milestone report.

				← Past	↓ Present	↗ Trending	↗ Trending	→ Future	
ID	Schedule Subphase	Milestone	Available Slack	Planned Completion (Baseline 4)	Forecast Completion Date	Variance from Baseline (Days)	Change from Previous Forecast (Days)	Trend to Meet Forecast Completion Date	Comments
1	Requirements	DDMS CM JAD completed	N/A	N/A	15-Jun-21	N/A		Completed	Completed June 15.
2	Requirements	DDMS RDISP JAD completed	N/A	N/A	8-Jul-21	N/A	16	Completed	Completed July 8.
3	Readiness	Start of Gartner readiness assessment review #1	N/A	N/A	12-Jul-21	N/A		Completed	Started July 12.
4	Requirements	Complete Draft Requirement - Facility Registration	Not on Critical Path	1-Apr-21	26-Jul-21	78	7	Trending to Forecast Completion	
5	Requirements	Complete Draft Requirement -DFS	Not on Critical Path	21-Jul-21	12-Aug-21	15		Trending to Forecast Completion	
6	Requirements	MIM input JAD completed	Critical Path	N/A	13-Aug-21	N/A	NEW	Trending to Forecast Completion	MIM input JADs and MIM output JADs have been split up to allow us to advance some work for HAPG
7	Requirements	Complete Draft Requirement- Direct Short Term Ops v1	Approaching Critical Path	N/A	19-Aug-21	N/A	13	Trending to Forecast Completion	
8	Requirements	DDMS UCM JAD completed	Not on Critical Path	N/A	31-Aug-21	N/A	43	Potential Delay to Forecast Completion	UCM VCR JADs have been postponed to August as the completion of the work will be later than anticipated
9	Requirements	DDMS IS JAD completed	Not on Critical Path	N/A	7-Sep-21	N/A	37	Potential Delay to Forecast Completion	IS VCR JADs have been postponed to August as the completion of the work will be later than anticipated
10	Requirements	DDMS SEM JAD completed	Not on Critical Path	N/A	8-Oct-21	N/A	NEW	Trending to Forecast Completion	DDMS SEM requirements have been advanced to allow the current Control Room resource to take on this work
11	Requirements	MIM output JAD completed	Not on Critical Path	N/A	8-Oct-21	N/A	NEW	Trending to Forecast Completion	
12	Readiness	Start of Gartner readiness assessment review #2	Not on Critical Path	N/A	1-Nov-21	N/A		Trending to Forecast Completion	
13	Market Rules/Market Manuals Approval	MPM & Market Administration (Batch 2) Technical Panel Meeting - Vote to Recommend	Not on Critical Path	15-Feb-22	15-Feb-22			Trending to Forecast Completion	
14	Readiness	Start of Gartner readiness assessment review #3	Not on Critical Path	N/A	6-Jun-22	N/A		Trending to Forecast Completion	
15	Solution Development	Complete DDMS Development	Not on Critical Path	N/A	20-Jun-22	N/A	-30	Trending to Forecast Completion	Completion of DDMS development is advanced due to advancement of DDMS SEM work
16	Solution Development	Complete MIM Back End Development	Critical Path	5-Jul-22	24-Jun-22	-6	-4	Trending to Forecast Completion	
17	Quality Assurance	DSO Milestone 10 Complete DSO FAT	Approaching Critical Path	N/A	29-Jul-22	N/A		Trending to Forecast Completion	
18	Market Rules/Market Manuals Approval	Calculation Engine (Batch 5) Technical Panel Meeting - Vote to Recommend	Not on Critical Path	N/A	11-Aug-22	N/A	NEW	Trending to Forecast Completion	
19	Quality Assurance	MIM back end system testing Complete	Not on Critical Path	1-Sep-22	29-Aug-22	-3	-1	Trending to Forecast Completion	
20	Solution Development	Complete MIM EMI Development	Not on Critical Path	N/A	26-Sep-22	N/A	13	Trending to Forecast Completion	
21	Solution Development	Complete MIM EMAT Development	Approaching Critical Path	N/A	24-Oct-22	N/A	-50	Trending to Forecast Completion	MIM EMAT work requires Ex-Post Operations BRD to be completed

				← Past	↓ Present	↗ Trending	↗ Trending	→ Future	
ID	Schedule Subphase	Milestone	Available Slack	Planned Completion (Baseline 4)	Forecast Completion Date	Variance from Baseline (Days)	Change from Previous Forecast (Days)	Trend to Meet Forecast Completion Date	Comments
22	Quality Assurance	Start of Gartner readiness assessment review #4	Not on Critical Path	N/A	7-Nov-22	N/A		Trending to Forecast Completion	
23	Readiness	MIM EMI system testing complete	Not on Critical Path	4-Nov-22	15-Nov-22	7	16	Trending to Forecast Completion	
24	Quality Assurance	DSO Milestone 12 DSO Sytem Testing Complete	Approaching Critical Path	9-Dec-22	8-Dec-22	-1	NEW	Trending to Forecast Completion	
25	Quality Assurance	MIM EMAT system testing complete	Approaching Critical Path	4-Nov-22	13-Dec-22	27	-47	Trending to Forecast Completion	MIM EMAT system testing is dependent on completion of MIM EMAT development
26	Market Rules/Market Manuals Approval	Settlements, Metering & Billing (Batch 4) Technical Panel Meeting - Vote to Recommend	Not on Critical Path	17-Jan-23	17-Jan-23			Trending to Forecast Completion	
27	Quality Assurance	Reports system testing complete	Near Critical Path	28-Dec-22	20-Jan-23	17		Trending to Forecast Completion	
28	Solution Development	Complete CAMS Development	Approaching Critical Path	N/A	1-Feb-23	N/A		Trending to Forecast Completion	
29	Quality Assurance	Operational tools Integration testing complete	Near Critical Path	4-Apr-23	27-Mar-23	-6	-17	Trending to Forecast Completion	
30	Quality Assurance	Reports Integration testing complete	Near Critical Path	27-Mar-23	20-Apr-23	16		Trending to Forecast Completion	
31	Quality Assurance	External Training Delivered	Not on Critical Path	18-Apr-23	26-Apr-23	6	30	Trending to Forecast Completion	
32	Quality Assurance	Complete Reports Acceptance testing	Not on Critical Path	6-Jun-23	29-Jun-23	17		Trending to Forecast Completion	
33	Market Rules/Market Manuals Approval	Market & Systems Operations (Batch 3) Technical Panel Meeting - Vote to Recommend	Not on Critical Path	N/A	10-Aug-23	N/A		Trending to Forecast Completion	
34	Quality Assurance	Complete DSO Audit	Near Critical Path	N/A	18-Sep-23	N/A	-11	Trending to Forecast Completion	
35	Quality Assurance	Operational tools acceptance testing completed	Critical Path	28-Sep-23	13-Oct-23	10	-1	Trending to Forecast Completion	
36	Readiness	Complete Control Room Training	Near Critical Path	N/A	3-Nov-23	N/A	39	Trending to Forecast Completion	
37	Market Rules/Market Manuals Approval	MC/BOD Conditional approval - Mkt. & Sys.Ops. Rules & Manuals	Not on Critical Path	N/A	10-Nov-23	N/A	10	Trending to Forecast Completion	
38	GO LIVE	In Production (GO LIVE)	Critical Path	30-Nov-23	29-Nov-23	-1	-1	Trending to Forecast Completion	

Legend - Available Slack	
Critical Path	Milestone has 0-10 working days of available slack
Near Critical Path	Milestone has 11-30 working days of available slack
Approaching Critical Path	Milestone has 31-60 working days of available slack
Not on Critical Path	Milestone has greater than 60 working days of available slack

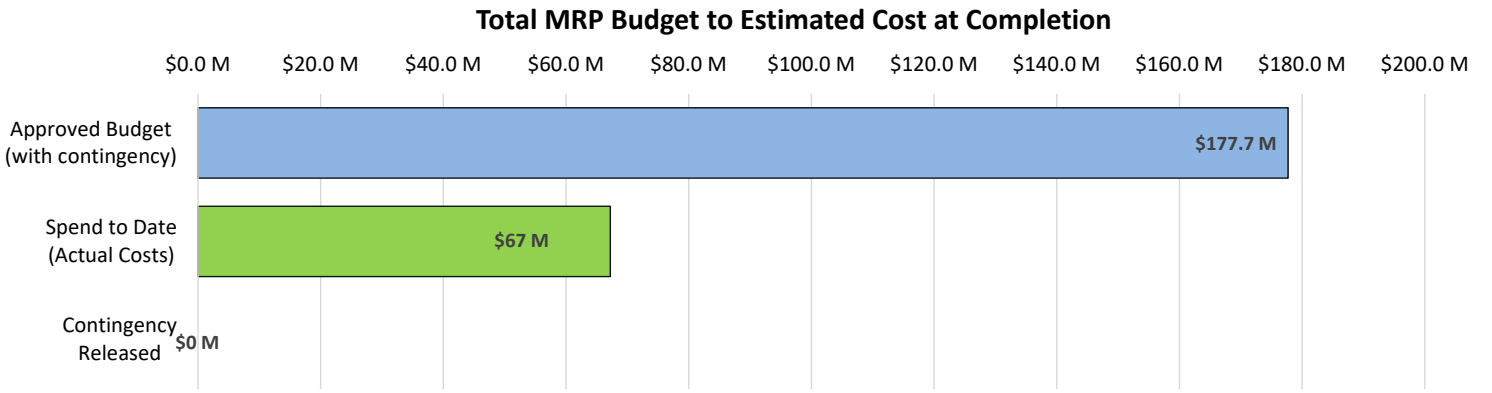
Legend - Trend to Meet Forecasted Completion Date	
Ahead of Forecast Completion	Progress is anticipated to be ahead of the forecast completion date, no issues to raise
Trending to Forecast Completion	Progress is on schedule to meet the forecast completion date, no issues to raise
Potential Delay to Forecast Completion	A delay greater than 10 working days to the forecast completion date of the milestone has materialized, and mitigations are under development to correct the delay
Delay to Forecast Completion	A delay greater than 10 working days to the forecast completion date of the milestone has materialized, with no established mitigations to correct the delay

MRP Energy - Progress Report

For Reporting Period: 01/June/2021 to 30/June/2021

Financial Status

KPI	Type	Total approved (with contingency)	Budget Contingency Available	Spend to Date (Actual Costs)	Forecast Cost at Completion	Variance to Approved Budget
✓	CapEx	$150.4 M	$10 M	$49 M	$150.4 M	$0 M
✓	OpEx	$27.3 M	$0 M	$18 M	$27.3 M	$0 M
✓	**Total**	**$177.7 M**	**$10 M**	**$67 M**	**$177.7 M**	**$0 M**

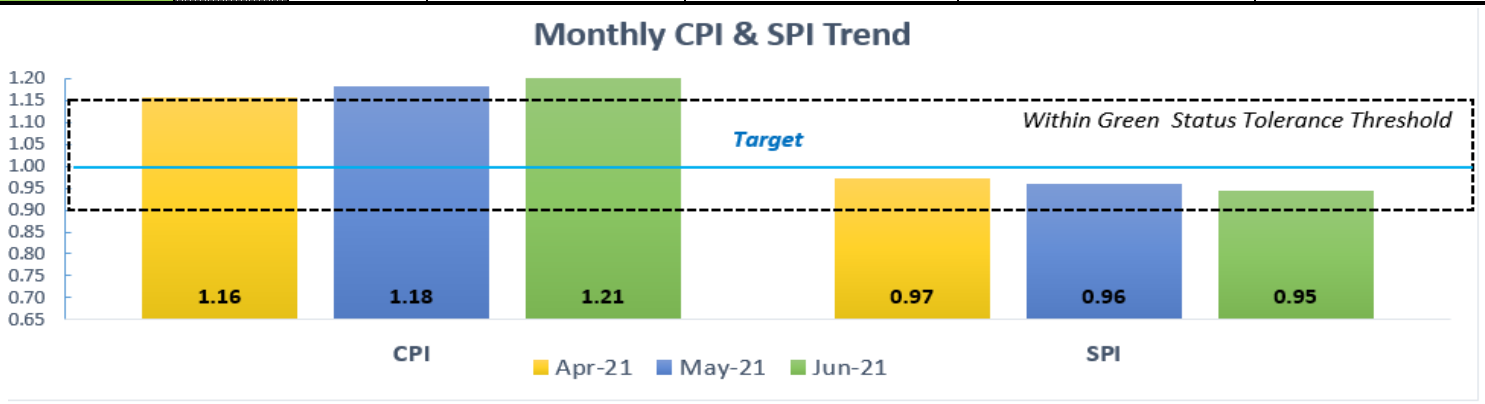


Budget: The life-to-date spend is $67 M (38%) against the Board-approved budget of $177.7M including contingency.

Overall Schedule Status

Schedule Health KPI (within Contingency)	% Overall Planned	% Overall Completion	Project Start Date	Approved Project Completion with Cont.	Contingency Available in days	Forecast Completion date	Schedule Variance (%)
✓	51.4%	48.5%	01-Jan-17	31-May-24	183	30-Nov-23	-2.8%

SPI & CPI Key Performance Index	SPI	CPI	Planned Value (PV) $000's	Earned Value (EV) $000's	Actual Cost (AC) $000's	(*) Variance to Schedule in days
Behind Schedule	0.95		$86,195	$81,507	$67,152	-20
Under Budget		1.21				



Notes: SPI and CPI are at "green" status. An updated methodology for CPI measurements will be proposed to the PSC/ESC at the August meeting.

Page Intentionally Blank

AUGUST 16, 2021

Market Renewal Program (MRP) Strategic Risk Report Appendix B

Market Renewal Program (MRP) Strategic Risks

Risk #	Strategic Objective	Risk Event Description	Management Risk Assessment					
			Residual			Target Risk Level	Risk Trend	Mitigation Status
			Impact	Likelihood	Risk Level			
1	Program Delivery	Market Participants are unprepared for technology and market operation at go-live date.	Significant	Likely	Critical	Low	-	●
2	Market Design	Market Participants challenge MRP rules at the OEB.	Moderate	Almost Certain	Critical	Critical	-	●
3	Market Design & Implementation	Market systems and related processes produce materially unexpected or unacceptable results.	Significant	Possible	High	Medium	-	●
4	Integration	IESO is unable to effectively integrate technical solutions and internal processes given complexity and volume.	Moderate	Likely	High	Medium	-	●
5	Program Delivery	IESO is unable to implement MRP Energy on time and on budget due to unexpected deliverable delays, uncertainties in forecasting task details and time estimates.	Moderate	Almost Certain	Critical	Medium	↓	●
6	Market Design	IESO is unprepared to respond to unforeseen design and/or implementation flaws post go-live.	Moderate	Almost Certain	Critical	Low	-	●
7	Program Delivery	Internal IESO is unprepared to use technology solutions and operate the market.	Moderate	Likely	High	Medium	-	●

RISK TREND

× Closed risk or risk is no longer applicable

\- No change

↓ Residual Risk Level is on a downward trend/Residual Risk Level has lowered

↑ Residual Risk Level is on an upward trend/Residual Risk Level has increased

MITIGATION HEALTH STATUS (descriptions in Appendix 2)

● Unfavourable

● Developing

● Neutral

● Positive

1	MARKET PARTICIPANT READINESS				Risk Owner: Jessica Savage
Strategic Objective: Prepare Market Participants in advance of go-live to ensure successful delivery of the MRP-RSS Program.		**Impact**	**Likelihood**	**Risk Score**	**Trend**
Risk Description: Market Participants are unprepared for technology and market operation at go-live date.	**RESIDUAL**	Significant [4]	Likely [4]	**Critical [16]**	—
	TARGET	Minor [2]	Possible [3]	**Low [6]**	

Why is this risk important? Market Participant readiness is critical to the launch and acceptance of the MRP-RSS program and will lead to the demonstration of benefits. As we execute on the scheduled MRP-RSS deliverables, we will gain more insight into the level of preparedness.

Root Causes	Impacts
• An inability to understand the requirements and readiness of Market Participants prior to go-live; • Inability to proactively identify requirements and to track, monitor and manage Market Participant deliverables within the Program; and • Market Participants do not have the internal capacity to prepare and incorporate changes derived from Market Renewal Program.	• Threat to IESO's achievement of MRP's key objectives: 1) Enhanced reliability, 2) Operational certainty for IESO and Market Participants; 3) Increased system efficiency; 4) Enabling future markets

Controls/Control Effectiveness	Score
COMMUNICATION & STAKEHOLDER ENGAGEMENT Engagement services implemented as per Communication and Stakeholder Plan.	3
RESOURCES Resource was hired to build out the Change Management & Adoption/Benefits Realization program in order to ensure Market Participant readiness.	3
PROGRAM MANAGEMENT Monitoring, tracking and reporting on program schedule and resources.	3
RISK MANAGEMENT Continuous identification, assessment, response, and reporting of project, operational, and strategic risks facing the program.	4

Mitigation	Due	Status
MARKET READINESS STRATEGY The Market Readiness Strategy has been drafted, which has component tactical elements, including participant segmentation and participant support plans to be delivered over the balance of 2021. These tactical activities, when implemented, establish the foundation for readiness for in-service.	Q4 2021	neutral
INDEPENDENT REVIEW Gartner to conduct a series of readiness reviews, including the effective management of external participant readiness for change.	1st review- Q3 2021	neutral
MARKET READINESS ASSESSMENT Develop Market Readiness assessment criteria per Market Participant type to measure readiness.	Q1 2022	developing

2	MARKET RULES CHALLENGES AT OEB				Risk Owner: Jessica Savage
Strategic Objective: Successfully bringing into effect new market rules as part of the implementation of the market renewal designs.		**Impact**	**Likelihood**	**Risk Score**	**Trend**
Risk Description: Market Participants challenge MRP rules at the OEB.	**RESIDUAL**	Significant [4]	Almost Certain [5]	**Critical [20]**	—
	TARGET	Moderate [3]	Almost Certain [5]	**Critical [15]**	

Why is this risk important? It is almost certain that market participants will challenge MRP rules at the OEB, the potential impact is significant and our ability to mitigate against the worst potential impacts is limited until the challenge occurs and challenge details are known.

Root Causes	Impacts
• The *Electricity Act* provides market participants with an avenue to challenge new market rules, at little cost to the participant; • Inability to satisfying (potentially competing) stakeholder preferences (e.g. Market Participant Capacity contracts); • Inability to develop clear, consistent, and enforceable rules within the project timelines; and • Ineffective stakeholder consultation/communications.	• Threat to IESO's achievement of MRP's key objectives: 1) Enhanced reliability, 2) Operational certainty for IESO and Market Participants; 3) Increased system efficiency; 4) Enabling future markets. • Multiple challenges from Market Participants may result in reduction in IESO's ability to successfully defend. • Significant project delay, reduced value or efficacy of residual design elements, the need for re-design and associated implementation work, increased costs, reputational damage, and stakeholder confusion are all impacts should rules be impugned or OEB finds challenged rules are contrary to the purposes of the Act or unjustly discriminatory against a participant or classes of participants.

Controls/Control Effectiveness	Score
MARKET RULES & MARKET MANUAL DRAFTING STRATEGY • Market Rules and Market Manuals are being drafted in tandem with significant legal involvement through the drafting process.	3
ENGAGEMENT • Stakeholder Engagement (adhering to IESO Engagement Principles) to increase transparency and tracking of stakeholder comments and IESO responses. • Focused Implementation Engagement Sessions with key stakeholders. • Technical Panel – another forum where critical issues may be identified and addressed.	3

Mitigation	Due	Status
OEB EDUCATION AND OUTREACH Education and outreach efforts to strengthen OEB's understanding of the foundational changes for MRP are planned to take place over the next couple of months between IESO and OEB Senior Management teams.	Oct 2021	developing

3	DESIGN & IMPLEMENTATION FLAW DISCOVERY				Risk Owner: Jessica Savage
Strategic Objective: Ensure new market systems functionality and implementation reflects the market design expected outcomes pre and post go-live.		**Impact**	**Likelihood**	**Risk Score**	**Trend**
Risk Description: Market systems and related processes produce materially unexpected or unacceptable results.	**RESIDUAL**	Significant [4]	Possible [3]	**High [12]**	—
	TARGET	Moderate [3]	Possible [3]	**Medium [9]**	
Why is this risk important? Diligent and adequate testing of optimization solutions and associated processes measures MRP-RSS program market readiness while allowing for early detection and response to gaps/defects/unforeseen results from the design and/or implementation.					

Root Causes	Impacts
• Despite best efforts, inability to proactively solve design and/or implementation flaws prior to go-live. • Inadequate systems and tools to test optimization and expected market outcomes in advance and post go-live. • Market outcomes produce expected results but are not within acceptable thresholds.	• Threat to IESO's achievement of MRP's key objectives: 1) Enhanced reliability, 2) Operational certainty for IESO and Market Participants; 3) Increased system efficiency; 4) Enabling future markets • Undiscovered design & implementation flaws create more opportunities for market challenges, system reliability issues, reputational impact, etc

Controls/Control Effectiveness	Score
DEVELOPMENT OF FUNCTIONAL SPECIFICATIONS FOR VENDORS Vendors are provided with a set of functional specifications directly informed by the detail design.	3
DEVELOPMENT OF BUSINESS PROCESSES AND REQUIREMENTS Processes governing the future requirements are developed to ensure the business is organized and positioned to support the execution of the renewed market.	3
SYSTEM SUPPORT HAPG to validate, fix and test flaws, scenarios/use cases in response to mitigating unexpected outcomes and unacceptable results.	3

Mitigation	Due	Status
PRE-GO-LIVE TESTING MRP deliverables will undergo numerous stages of system and process testing (Static Testing, Factory Acceptance Testing, Site Acceptance Testing, System Integration Testing, User Acceptance Testing and Market Trials) with the intent of ensuring the market outcomes are consistent with expectations.	Q4 2023	neutral
GO-LIVE ACCEPTANCE CRITERIA Define a set of criteria and thresholds that need to be met before placing MRP deliverables into service.	Q1 2022	developing
POST-GO-LIVE SIMULATOR Develop a new simulator to model and test a variety of market scenarios, helping discover any unintended market outcomes.	2024 (in-service)	developing

4 TECHNOLOGY INTEGRATION

Risk Owner: Rado Jovic

Strategic Objective: Establish an MRP-RSS program integration plan which adequately ensures internal stakeholders are prepared for go-live, thereby enabling the achievement of all the MRP strategic objectives identified in the Business Case.		**Impact**	**Likelihood**	**Risk Score**	**Trend**
Risk Description: IESO is unable to effectively integrate technical solutions and internal processes given complexity and volume.	**RESIDUAL**	Moderate [3]	Likely [4]	**High [12]**	—
	TARGET	Minor [2]	Likely [4]	**Medium [8]**	

Why is this risk important? Successful integration of new/upgraded technical solutions and processes enables MRP-RSS program delivery's success.

Root Causes	Impacts
• Volume of new systems or changes to existing systems provided by a variety of vendors. • Parallel development and implementation of systems leads to missing or revised requirements.	• Threat to IESO's achievement of MRP's key objectives: 1) Enhanced reliability, 2) Operational certainty for IESO and Market Participants; 3) Increased system efficiency; 4) Enabling future markets • Delays in testing and software development rework (additional cost to project). • Delays in successful MRP implementation and support from internal stakeholders.

Controls/Control Effectiveness	Score
MANAGEMENT & OVERSIGHT • Key role representation within the program • Interdependency Advisory Panel monitors interdependencies between MRP-RSS Program and other inflight projects within IESO capital project portfolio. • Program Design Change Management Process reviews deviations from published Detail Design.	3
BUSINESS INTEGRATION • Detailed Design Chapters, Process Maps, Process Specifications, and Information models and catalogues map interactions between business process and corresponding business requirements. • Process and Solution Stewards review MRP business requirements prior to development.	3
TECHNOLOGY INTEGRATION • Solution development and integration follows the Software Development Life Cycle (SDLC) process. Efforts are tracked against this process within the schedule. • Vendor alignment to SDLC process. Project managers monitor vendor deliverables. • IESO IT acts as a system integrator, directing the vendors' work, specifying interfaces, etc. • Reusing technology architectural patterns and cyber security thus reducing the amount of change.	3
PROJECT MANAGEMENT • Program Cost and Schedule Impact Assessment is factored into MRP/RSS program design change management process.	3

Mitigation	Due	Status
REQUIREMENT TRACEABILITY Requirement traceability ensures that the detailed design is implemented in both processes and solutions. Business Requirement Documents continue to be developed and added to the traceability tool, JIRA.	Q4 2021	positive
STATIC TESTING Static Testing ensures that the requirements are consistent with detailed design, before solutions were built. This is achieved by conducting requirement walkthroughs and tabletop exercises ("day in the life").	Q4 2021	positive
SYSTEM INTEGRATION TESTING Solution Integration and Interfaces Testing confirms exchange of data between solutions as per requirements.	Q1 2023	developing
USER ACCEPTANCE TESTING (UAT) User Acceptance Testing assures that all business processes can be executed as designed, and that all solutions and procedures that support those processes are in place.	Q2/Q3 2023	developing

5	PROGRAM DELIVERY TRACKING				Risk Owner: Jessica Savage
Strategic Objective: MRP-RSS Program deliverables are achieved within current cost, scope and schedule parameters as approved by the Board of Directors.		**Impact**	**Likelihood**	**Risk Score**	**Trend**
Risk Description: IESO is unable to implement MRP Energy on time and on budget due to unexpected deliverable delays, uncertainties in forecasting task details and time estimates.	**RESIDUAL**	Moderate [3]	Almost Certain [5]	**Critical [15]**	↓
	TARGET	Moderate [3]	Possible [3]	**Medium [9]**	
Why is this risk important? Program governance and program management are key drivers to deliver MPR-RSS program on schedule and on budget.					

Root Causes	Impacts
• Unforeseen challenges with complex integration for business and technology solutions. • Unexpected changes to resource availabilities. • Inaccurate or delayed critical path analysis and cost reporting. • Lack of visibility on potential scope changes. • Lack of project management controls.	• Threat to IESO's achievement of MRP-RSS's key objectives: 1) Enhanced reliability, 2) Operational certainty for IESO and Market Participants; 3) Increased system efficiency; 4) Enabling future markets • Unforeseen expenses and request for additional contingency. • Loss of credibility with stakeholders and the Board. • Potential delays to other IESO business priorities.

Controls/Control Effectiveness	Score
PROGRAM MANAGEMENT • Progress and changes from the baseline costs published in Business Case (Oct 2019) are reported on a monthly basis. • Program status is reported against program's schedule critical path on a bi-weekly basis. Weekly project status touch-points. • Continuous Review of governance structures, processes, and tools. • Aligned project's resource management tools, processes and accountabilities with the Project Management Office.	3
VENDOR MANAGEMENT • Status of project deliverables (as per Statement of Work) and risk mitigation actions are reviewed weekly. Risks are assessed and reviewed via monthly risk call with vendor. • Vendor costs verification processes.	2
PROGRAM GOVERNANCE • MRP-RSS program governance, terms of reference, and roles & accountability reviewed, updated, and approved.	3

Mitigation	Due	Status
INDEPENDENT REVIEW Gartner to conduct a series of readiness reviews, including the effectiveness of project management services against scope, schedule and budget.	1st review - Q3 2021	neutral

6	POST GO-LIVE PREPAREDNESS				Risk Owner: Lechard Kula
Strategic Objective: Put in place appropriate strategies and tactics to adequately prepare internal stakeholders to address material unintended consequences of MRP implementation without significant delay.		**Impact**	**Likelihood**	**Risk Score**	**Trend**
Risk Description: IESO is unprepared to respond to unforeseen design and/or implementation flaws post go-live.	**RESIDUAL**	Moderate [3]	Almost Certain [5]	**Critical [15]**	—
	TARGET	Minor [2]	Possible [3]	**Low [6]**	
Why is this risk important? Pro-active planning to ensure availability of skills, knowledge, and resources following market go-live helps mitigate lack of preparedness and/or failure to respond on time to unexpected events.					

Root Causes	Impacts
• Despite best efforts, inability to proactively identify all outcomes of the renewed market due to significant complexity. • Lack of appropriate and expert resources to address material flaws that are not predicted. • Potential new government policies impacting markets.	• Threat to IESO's achievement of MRP's key objectives: 1) Enhanced reliability, 2) Operational certainty for IESO and Market Participants; 3) Increased system efficiency; 4) Enabling future markets • Persistent bias in day-ahead forecast, resulting in volatility in real-time.

Controls/Control Effectiveness	Score
ENGAGEMENT & PLANNING Engage with MRP and internal/external stakeholders to identify potential areas of concern and develop plans to either address or limit impacts.	2
MRP TRANSITION TEAM A dedicated team "Continuous Market Improvement" has been setup at the beginning of 2021 to support MRP Transition.	3

Mitigation	Due	Status
MRP TRANSITION PLAN A plan outlining the shift in responsibilities (budget, roles, responsibilities, processes) between MRP project and line of business.	Q1 2022	developing
HUMAN & FINANCIAL RESOURCE AVAILABILITY Ensure key resources (e.g. internal Subject Matter Experts and external support) that understand MRP design, processes, and tools are available to respond to post go-live flaws.	Q4 2021	developing
POST-GO-LIVE SIMULATOR Develop a new simulator to model and test a variety of market scenarios, helping discover any unintended market outcomes.	2024 (in-service)	developing

7	INTERNAL READINESS				Risk Owner: Marlene Kadin
Strategic Objective: Prepare internal IESO business units in advance of go-live to ensure successful delivery of the MRP-RSS Program.		**Impact**	**Likelihood**	**Risk Score**	**Trend**
Risk Description: Internal IESO is unprepared to use technology solutions and operate the market.	**RESIDUAL**	Moderate [3]	Likely [4]	**High [12]**	—
	TARGET	Moderate [3]	Possible [3]	**Medium [9]**	

Why is this risk important? Readiness of our operations, our employees, and the use of our systems are critical to the launch and management of MRP-RSS program, including supporting external stakeholders.

Root Causes	Impacts
• Capacity and capability of resources. • Defective or poorly implemented technical systems. • Ineffective operational systems. • Poor quality and/or insufficient requirements. • Delayed delivery of scheduled efforts.	• Threat to IESO's achievement of MRP's key objectives: 1) Enhanced reliability, 2) Operational certainty for IESO and Market Participants; 3) Increased system efficiency; 4) Enabling future markets. • Additional costs with prolonged schedule delays. • Loss of talent.

Controls/Control Effectiveness	Score
STAKEHOLDER ANALYSIS Internal stakeholder community segmentation for the purposes of tailoring communications, training, and support.	2
IMPACT ANALYSIS Impact Analysis establishes the repository of changes and assesses the impact of those changes across 10 dimensions. It identifies adoption risks and informs the communication, training, support, and sustainment plans.	2
TRAINING A variety of training efforts have been established and continue to be rolled out throughout the course of the program. Examples include MRP Academy.	2
INTERNAL STAKEHOLDER COMMUNICATION Deployment of the stakeholder communication strategy throughout the course of the program.	2

Mitigation	Due	Status
STATIC TESTING (DAY-IN-LIFE) Testing of most impacted processes and roles to determine effectiveness of people and processes. Pilot test scheduled for August 2021 and a Suite of Static Testing will commence in September of 2021.	Q3 2021	developing
USER ACCEPTANCE TESTING (UAT) User Acceptance Testing assures that all business processes can be executed as designed, and that all solutions and procedures that support those processes are in place.	Q2/Q3 2023	developing
READINESS SURVEYS A series of surveys established to target different stakeholders and/or project-specific areas to understand readiness.	TBD	developing
CHANGE READINESS CRITERIA Criteria established to assess the state of people and process readiness.	TBD	developing
SUPPORT RESOURCE Change Champions and Super-User Network established to support program delivery (i.e. training and post go-live).	TBD	developing

Exhibit 1 – Control Status Scale

Exhibit 1: Control Status Scale

The following control status scale is used to measure the effectiveness of the control identified to mitigate a risk. It is important to note that the scales 1 to 4 are NOT to be considered in silo. For example, for a control to have a score of 4, it is a control that also has a score of 1, 2, and 3. The more oversight, management, analysis, and awareness of the control – the more effective the control.



1

- Reactive
- Repetitive Task/ Review
- No particular resource dedicated to effort
- Managed by Team
- Compliance
- Personal Protective Equipment (PPE)



2

- Reactive
- Periodic Task/ Review
- One resource dedicated to effort
- Managed by Department
- Operational
- Administrative Controls
- Engineering Controls



3

- Proactive
- Planned Task/ Review
- A few resources dedicated to effort
- Executive oversight/Approval
- Consulting
- Substitution (replace the hazard)



4

- Proactive
- Random Scheduled Task/Review
- Many resources dedicated to effort
- CEO/Board oversight
- Control Self-Assessment
- Elimination (physically remove the hazard)

Exhibit 2 - Mitigation Health Trend Status Scale

Exhibit 2: Mitigation Status Scale

Unfavourable

- Key actions are delayed and/or behind schedule; or
- Funding is uncertain / not yet approved.

Developing

- Actions are at a conceptual or early planning state; or
- Key actions have not started.

Neutral

- Actions have commenced and are tracking to plan;
- Timing/resource dependencies and prerequisites exist; or
- ELT trade-off discussions may be required.

Positive

- Actions are well underway (past mid-point) or nearing completion; or
- If required, interim (stop-gap) measures have been implemented.

Exhibit 3 – Risk Criteria

Exhibit 3: Risk Criteria

Impact Criteria – Strategic & Ops

Impact Score	Impact Level	Impact of Occurrence					
		Financial	Reputation	Legal / Regulatory	Workforce	Competitive Marketplace	Reliability & Resiliency
5	Critical	• Financial impact greater than 21% of budget • > $40 Million	• Concerns raised by multiple influential stakeholders • Decision and control is contrary to IESO mandate	• Deliberate non-compliance with legal obligations including market rules, that has a material impact on market participants or ratepayers	• Broad reduction in staff engagement • Inability to attract / retain skilled staff to execute all core strategies • Widespread (e.g. pandemic) incidence of mental/physical injury	• Market inefficiencies continue and with continued material long-term ratepayer costs	• Wide-scale disruption to critical infrastructure, services and bulk electricity system reliability lasting greater than two days
4	Significant	• Financial impact between 11% to 20% of budget • $11M to $40M	• Concerns raised by at least one influential stakeholder	• Non-compliance with legal obligations, including market rules, or negligence that has significant impact on market participants or ratepayers	• Sustained reduction in staff engagement • Inability to attract / retain skilled staff to execute one core strategy • Sporadic and localized mental/physical injury	• Significant market inefficiencies persist and mid-term ratepayer costs are further escalated	• Significant disruption to critical infrastructure, services and local area electricity system reliability lasting up to two days
3	Moderate	• Financial impact between 5% to 10% of budget • $5M to $10M	• Concerns raised by a group of moderately influential stakeholders	• Non-compliance with legal obligations, including market rules, or negligence that has moderate impact on market participants or ratepayers	• Sporadic reduction in staff engagement • Inability to attract / retain skilled staff to execute department objectives • Injury with permanent work restrictions	• Moderate market inefficiencies and short-term increase in ratepayer costs	• Temporary disruption to critical infrastructure and services isolated to local area electricity system reliability lasting up to one day
2	Minor	• Financial impact less than 2.5% of budget • < $5 Million	• Concerns raised by a single, moderately influential stakeholder	• Non-compliance with legal obligations, including market rules, or negligence that has minimal impact on market participants or ratepayers	• Isolated reduction in staff engagement • Inability to attract / retain skilled staff execute section deliverables • Injury with temporary work restrictions	• Immaterial market inefficiencies and impacts to minor ratepayer costs	• Negligible disruption to critical infrastructure and services with minor electricity system inefficiencies
1	Insignificant	• No financial impact	• Occasional questions raised by stakeholders seeking general information	• Non-compliance with legal obligations, including market rules, or negligence that has no impact on market participants or ratepayers	• Anticipated reductions in engagement for specific roles • Anticipated attraction or retention issues for specific roles • Isolated, no/minor injury	• Isolated impacts or impediments to competitive markets that are fully anticipated	• Insignificant impacts that can be addressed through existing operational controls

Exhibit 3: Risk Criteria

Impact Criteria – Project

Impact Score	Impact Level	Impact of Occurrence			
		Cost*	Schedule	Stakeholder Value	Objectives
5	Critical	• Financial impact over 20% of approved budget	• Schedule delay or missed milestone exceeds allocated contingency and/or impacts the delivery of other projects • Lesser of >20% time increase or >3 months	• Mission critical impact to deliverable quality • Widespread reputational impact: substantial negative media coverage, reaction from Ministry/government	• Critical impact to achieving majority of Project's Objectives leading to Project failure • Impact to delivery of other projects and/or operational interdependencies • Benefits would not be realized
4	Significant	• Financial impact between 10-20% over approved budget	• Schedule delay or missed milestone which impacts critical path activities and schedule exceeds allocated contingency • Lesser of 10% - 20% time increase or 3 months	• Significant impact to deliverable quality • Minimal impact to external brand and stakeholders	• Impact to achieving two or more of the Project's Objectives • Benefits realization uncertain • Missed compliance with Directives and/or Accountability Agreements
3	Moderate	• Financial impact of 5-10% over approved budget	• Schedule delay or missed milestone which impacts critical path activities however slippage remains within project schedule contingency • Lesser of 5% - 10% time increase or 2 months	• Moderate impact to deliverable quality that can be addressed within Project parameters (quality/cost/schedule) • Potential external impact to stakeholders	• Moderate disruption in achieving one of the Project's Objectives • Benefits will be realized later than anticipated • Potential impact to brand internally
2	Minor	• Financial impact of 3-5% over approved budget	• Schedule delay or missed milestone with minor impact the on project's critical path and course corrected in short period • Lesser of 3%-5% time increase or 1 month	• Minor impact on deliverable quality • Minor external impacts to stakeholders	• Minor impact on the achievement of any of the Project's Objectives
1	Insignificant	• Insignificant cost impact - <3%	• Schedule delay or missed milestone which does not impact the project's critical path • Lesser of time increase - <3% or 2 weeks	• No impact on deliverable quality • No external impacts to stakeholders	• No impact on the achievement of any of the Project's Objectives

ieso
Connecting Today. Powering Tomorrow.

Exhibit 3: Risk Criteria

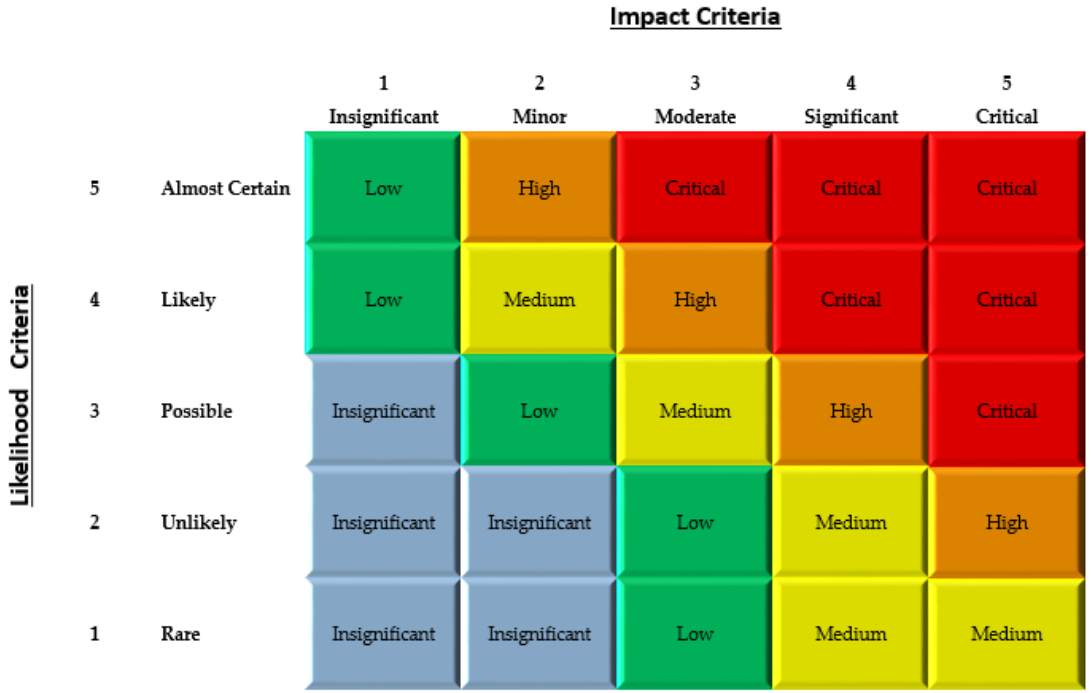
Likelihood Criteria – Strategic/Operational/Project

Likelihood Score	Description	Likelihood Value	Factors to consider that drive likelihood
5	Almost Certain	95% to 100%	• Maturity / complexity of the process or system • Past occurrences of the risk event • External factors (economic, competitive, regulatory) • Experience of management / employees / board • Performance indicators / industry trends • Regulatory changes • Effectiveness of training • Adherence to policies & procedures • Current controls, or lack of controls • Management's understanding of / focus on the risk
4	Likely	65% to 95%	
3	Possible	35% to 65%	
2	Unlikely	5% to 35%	
1	Rare	0% to 5%	

ieso
Connecting Today. Powering Tomorrow.

Exhibit 3: Risk Criteria

Risk Criteria Matrix



ieso
Connecting Today. Powering Tomorrow.

AUGUST 17, 2021

Market Renewal – Energy Project Update

Purpose and Executive Summary

Purpose of Item

- To provide status updates on the Market Renewal – Energy Project (MRP)

Executive Summary

- Overall project health is favourable where near-term delays are being monitored closely and actions are underway to mitigate potential impacts on overall schedule

Performance Indicator	Status	Comment
Business Objectives	On Track	Expect all business objectives to be achieved
Budget	On Track	Current overall project cost is forecast to be within budget
Schedule	On Track / Actively Managing	Business requirements gathering delayed due to underestimated effort and key resource unavailability. Mitigating schedule impact by onboarding additional staff and reprioritizing work. Currently no impact to go-live date

Program Financial Status

The life-to-date spend is $67 M (38%) against the Board-approved budget of $177.7M including contingency.

Type	Total Approved (with Contingency)	Budget Contingency Available	Spend to Date (Actual Costs)
CapEx	$150.4 M	$10 M	$49 M
OpEx	$27.3 M	$0 M	$18 M
Total	**$177.7 M**	**$10 M**	**$67 M**

ieso
Connecting Today. Powering Tomorrow.

Schedule Overview

Schedule Sub-phase	Progress Indicator	Comments
Business Requirements	Delayed	• Defining requirements continues to progress for Market Registration, Prudential Security, Network Modeling, Day-Ahead Market, Real-Time Operations, Market Power Mitigation • Adoption of Joint Application Development sessions with key vendors to facilitate expedited translation of business requirements into functional tool specifications is helping to minimize further delays
Solution Development	On Track	• Software development ongoing for Market Registration and Prudential Security solutions • Hitachi ABB Power Grids (HAPG) developing software for Dispatch Scheduling and Optimization engine; IESO providing test data • Requirements stemming from the Joint Application Development sessions will likely result in the need to expand on the integration with HAPG solutions

Schedule Overview

Schedule Sub-phase	Progress Indicator	Comments
IESO Organizational Change Management & Readiness	On Track	• Detailed impact analysis to itemize changes and assess impact on processes, systems, and behaviours is underway. The impact analysis informs the detailed planning for Communications and Training design • Refreshed MRP landing page on the intranet, including the addition of learning modules
Market Rules & Market Manuals	On Track	• Market Power Mitigation rules and manuals will be published for market participant engagement in August 2021 • Technical Panel review starting in October 2021 with vote to provisionally recommend scheduled for February 2022

Schedule Overview

Schedule Sub-phase	Progress Indicator	Comments
Testing	On Track	• Testing of solutions for Market Registration and Prudential Security in progress • Static testing of requirements in progress • Preparing test plans, test data, test scenarios and test environments in advance of upcoming phases
Market Participant Support And Readiness	On Track	• Market Participant Readiness Strategy has been created, with tactical plans to be drafted in Q4 of 2021, informed by stakeholder input • First meeting of Technical Advisory Group took place in June; next meeting in mid-August to discuss participant segmentation and start developing detailed market participant support and readiness plans

ieso
Connecting Today. Powering Tomorrow.

MRP-RSS Program Readiness Review – Status

- First of four reviews is underway to assess state of readiness for Market Renewal – Energy Project (MRP) and Replacement of the Settlement System (RSS) Project
  - Readiness reports will highlight key program areas that are performing well towards readiness and key program areas that are not with recommendations for mitigation and correction
- Gartner reviewed project artifacts and conducted ten group interviews with staff to inform their assessment on the following readiness dimensions: governance; delivery assurance; technology & architecture; people/change management; and supplier management
- Report drafting is underway with the first readiness report and management response to be shared with the Markets Committee in October

MRP-RSS Program Readiness Review – Early Observations

- Positive feedback from Gartner on collaboration and communication; strong governance and risk frameworks
- Potential caution areas for MRP:
  - Ambitious implementation timeline
  - Resistance from market participants
  - Resource fatigue stemming from the length of the program
  - Interdependency management of multiple systems in a complex multi-vendor program

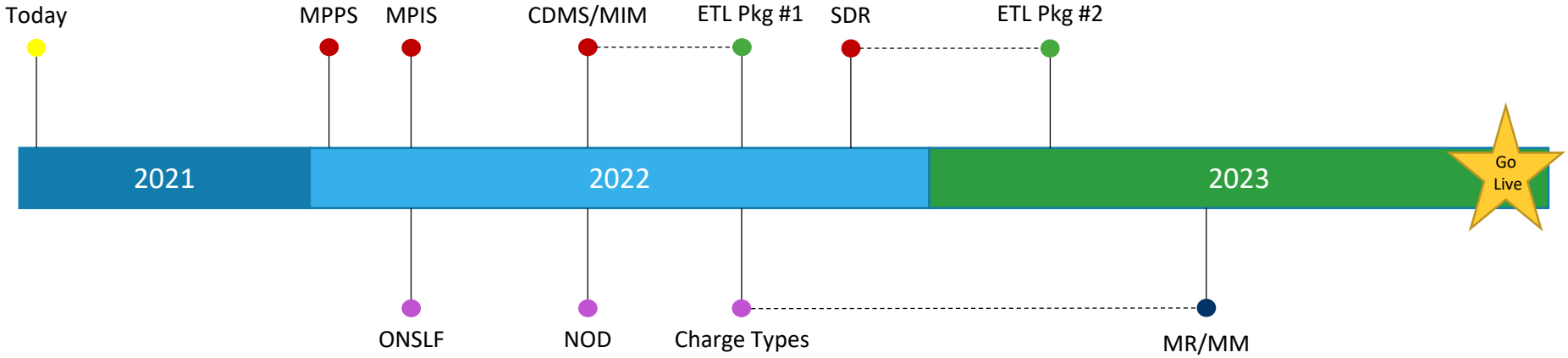
ieso
Connecting Today. Powering Tomorrow.

MRP-RSS Interdependency Risk

- At the March 2021 Markets Committee meeting an action was taken to track MRP-RSS interdependency risk on an ongoing basis
- MRP and RSS independency risk is being mitigated through joint program governance and by phasing RSS implementation; MRP/RSS teams are coordinating to ensure all component process and systems effectively combined to function as one from bid to bill
- Integration issues reviewed weekly at MRP/RSS management and Information Technology meetings and are reflected in coordinated quality assurance plan as part of the overall MRP testing strategy
- MRP hiring a Senior Integration Lead to provide a longer term focus on ensuring that program deliverables of technology, data and processes are being effectively integrated

Key Areas of Integration between MRP and RSS

Planned Development Completion for Dependent Systems/Activities



Legend

- MRP Systems
- RSS Systems
- MRP RSS ETL Modifications
- Market Rules
- Dependencies

Acronyms

MPPS – Market Participant Prudential System	RSS – Replacement of the Settlement System
MPIS – Market Participant Information System	ONSLF – Online Settlement Forms
CDMS – Customer Data Management System	NOD – Notice of Disagreement
MIM – Market Information Management System	ETL – Extract, Transform, Load
SDR – Surveillance Data Repository	MR/MM – Market Rules & Market Manual

ieso
Connecting Today. Powering Tomorrow.

SEC INTERROGATORY 23

Issue 4.4 Is the IESO's MRP Baseline Schedule and Budget for each year of the MRP appropriate?

4.4-SEC-23

INTERROGATORY

[A-2-2, Attach 1, p.2] Please provide a copy of the IESO Integrated Project Plan and Project Charter for the MRP.

RESPONSE

These are products prepared for internal use in support of project approval, monitoring and control of our individual projects. Further, The IESO also notes that the OEB's decision in EB-2019-0002 ordered the IESO to include the MRP Business Case within this filing, which has been done. See response to Schedule 14 - 4.4 SEC 22 for other MRP reporting provided to the project steering committee and IESO Board of Directors.

Page Intentionally Blank

SEC INTERROGATORY 24

Issue 4.5 - Is the IESO's MRP Business Case appropriate?

4.4-SEC-24

INTERROGATORY

[G-2-1, Attachment 1] With respect to the Market Renewal Program Business Case:

a. Please detail all material changes to the design/scope of the Market Renewal Program since the release of the business case on October 22, 2019.

b. [p.73-74] Section 7.1 provides the IESO's MRP risk mitigation plans at the end of Q3, 2019. Please provide an update on the risks and mitigation plans. Please also provide information on any subsequent identified risks.

RESPONSE

a. There have not been any material changes in scope since the release of the October 2019 MRP Business Case.

b. See response to Schedule 14 - 4.4 SEC 22.

Page Intentionally Blank

AMPCO INTERROGATORY 30

Issue 4.5 Is the IESO's MRP Business Case appropriate?

4.5-AMPCO-30

INTERROGATORY

Exhibit G-2-1, Attachment 1, Page 10

In 2017, the IESO commissioned an independent report: The Future of Ontario's Electricity Market - A Benefits Case Assessment of the Market Renewal Project, The Brattle Group, April 20, 2017.

Please provide a copy of the report or link to the report.

RESPONSE

The requested report was included previously in Exhibit I, Tab 6.1, Schedule 10.21, Attachment 1, as a part of EB-2019-0002. A link to the requested report is also provided as follows:

https://ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/Benefits-Case-Assessment-Market-Renewal-Project-Clean-20170420.ashx

Please note that the 2017 MRP Benefits Case "Brattle Group Report" was an initial study to confirm directionally that MRP would provide sufficient benefits and to guide the IESO to pursue a more formal business case. The subsequent 2019 MRP Business Case is more relevant given it used information specific to Ontario as inputs for the financial assessment of benefits. The IESO also notes that the OEB's decision in EB-2019-0002 ordered the IESO to include the MRP Business Case within this filing, which has been done.

Page Intentionally Blank

AMPCO INTERROGATORY 31

Issue 4.5 Is the IESO's MRP Business Case appropriate?

4.5-AMPCO-31

INTERROGATORY

Ref: Exhibit G-2-1, Attachment 1 Page 8

The MRP Business Case indicates thorough financial assessment of the new market design has concluded that the program is financially viable, delivering at least $750 million in net financial benefits to Ontario consumers over the first 10 years of implementation.

a) Please explain how the Brattle Report was used in the financial assessment provide in the MRP Business Case.

b) With respect to the Energy Stream financial assessment, please compare the findings of the Brattle Report to the findings in the MRP Business Case.

RESPONSE

a) The 2017 MRP Benefits Case "Brattle Group Report" was an initial study to confirm directionally that MRP would provide sufficient benefits and to guide the IESO to pursue a more formal business case. The subsequent 2019 MRP Business Case is more relevant given it used information specific to Ontario as inputs for the financial assessment of benefits. The IESO also notes that the OEB's decision in EB-2019-0002 ordered the IESO to include the MRP Business Case within this filing, which has been done.

b) As described in response to a), the Brattle Group Report and the MRP Business Case were developed for different purposes and are therefore not directly comparable.

Page Intentionally Blank

AMPCO INTERROGATORY 32

Issue 4.5 Is the IESO's MRP Business Case appropriate?

4.5-AMPCO-32

INTERROGATORY

Ref: Exhibit G-2-1 Attachment 1 Page 8

The MRP costs are divided into five category components namely: IESO Labour, IT (Hardware and Software), Professional and Consulting, Contingency and Other (Interest and Rent).

The contingency component is $16 million or 9%. Please provide a breakdown of the MRP contingency used to date.

RESPONSE

To date, the IESO has used $6 million of the contingency by allocating this amount to the program budget. Through the schedule and budget update exercise, the IESO expanded the program budget envelope from $170M ($154M + $16M contingency) to $177.7M ($167.7M + $10M contingency).

Page Intentionally Blank

REASCWA INTERROGATORY 22

Issue 4.5 Is the IESO's MRP Business Case appropriate?

4.5-REASCWA-22

INTERROGATORY

Reference: Exhibit G-2-1, Attachment 1, Page 14

a. The MRP Business Case states implementation costs to be approximately $170 million. Does this cost include costs that IAM market participants will need to incur to be ready for the IESO planned MRP go-live date of November 2023?

b. If not, does the IESO have an estimate of costs that IAM market participants will need to incur to be ready for the planned go-live date?

c. Please provide any analysis and documents related to b) above.

RESPONSE

a. No.

b. The IESO does not have an estimate of costs that market participants will need to incur to be ready for the planned go-live date. However, market participant readiness is a key component for the Market Renewal Program (MRP) go-live. Planning is underway for the market participant readiness component of the MRP's implementation phase. The IESO will work with stakeholders through the Technical Advisory Group, and outline training and support plans to work on market participant readiness. These planning activities will inform timing and any potential impacts to schedule and budget.

c. See response to b).

Page Intentionally Blank

REASCWA INTERROGATORY 23

Issue 4.5 Is the IESO's MRP Business Case appropriate?

4.5-REASCWA-23

INTERROGATORY

Reference: Exhibit G-2-1, Attachment 1, Page 14

a. If the IAM market participant costs were to be factored into the MRP Business Case analysis, can the IESO provide any changes to the dollar benefits of implementing the MRP?

b. Please provide any analysis and documents related to a) above.

RESPONSE

a) The MRP Business Case focused on why changes to Ontario's energy market are required, addressing known flaws and inefficiencies, and the value of creating a new platform to enable future market improvements and evolution. The Business Case also includes an assessment of the net benefits of the energy market enhancements over the first 10 years. In 2019 the IESO engaged stakeholders on the development of the Business Case to aid understanding and build support. The IESO held five engagement sessions, including an in-depth look at the benefits. Stakeholders contributed feedback and participated in discussions into topics such as costs and risks that were factored into the MRP Business Case. The IESO Board approved the Business Case in October of 2019.

The MRP Business Case cost estimate included costs within IESO's control: expenditure and implementation for the new energy market design and the incremental/decremental impact (e.g., avoided cost) of operations and maintenance compared to the current system. Further, the MRP Business Case covers the calculation of benefits from the consumer's perspective. Market participant costs were therefore disconnected from cost/benefit assessment for consumers and would not have been included even if they were available. The MRP Business Case uses conservative assumptions and many potential benefits have not been quantified. Overall, the IESO is confident that the realized value of the MRP will exceed the benefits that are presented in the MRP Business Case.

b) See response to a).

Page Intentionally Blank

VECC INTERROGATORY 5

Issue 4.5 Is the IESO's MRP Business Case appropriate?

4.5-VECC-5

INTERROGATORY

With respect to the MRP the IESO identifies the value of three potential benefits: (1) Constrained-On CMSC $450M; (2) Constrained-off CMSC $450M and (3) Market Efficiency Benefits $525M.

a) We are unable to locate the derivation of those values. If not provided please provide the underling calculation for these figures.

RESPONSE

(a) For clarity, only the Constrained-off CMSC amount is considered ($450M) in the quantifiable benefits for the Market Renewal Program (MRP). While the IESO expects benefits from reductions in Constrained-On CMSC, these benefits were not quantified in the MRP Business Case. For the underlying calculations for determining CMSC, please see the formulas for charge type 105 in Section 2.2 of the IESO Charge Types and Equations list, available here: https://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/settlements/imo-charge-types-and-equations.ashx.

Market efficiency benefits of $525M include a breakdown as such: $190M from improved commitment, $285M from better intertie scheduling, $50M from improved competition. Refer to Exhibit G-2-1, Attachment 1 for the MRP Business Case, Figure, 3-4 and Section 3.7.1 of the MRP Business Case provides further information on the calculations.

Page Intentionally Blank

VECC INTERROGATORY 6

Issue 4.5 Is the IESO's MRP Business Case appropriate?

4.5-VECC-6

INTERROGATORY

Reference: Exhibit G-2-1, Attachment 1 MRP Energy Stream Business Case, page 60

a) IESO notes that the introduction of the SSM would eliminate the HOEP. Are there are any cost ramifications to stakeholders (other parties) who are reliant upon or use the HOEP as part of their business processes? If so, please explain what these might be and what cost/benefit might ensue with the HOEP elimination.

RESPONSE

a) With the renewed market, The Hourly Ontario Energy Price (HOEP) is being replaced with Locational Marginal Pricing (LMP), with non-dispatchable loads being settled on a zonal price. It is not possible for the IESO to comment on potential cost ramifications to stakeholders from this transition. It is an IESO objective to minimize system costs and impacts to participants. Further, market participant readiness is a key component for the Market Renewal Program (MRP) go-live. Planning is underway for the market participant readiness component of the MRP's implementation phase. The IESO will work with stakeholders through the Technical Advisory Group, and outline training and support plans to work on market participant readiness. These planning activities will inform timing and any potential impacts to schedule and budget.

Page Intentionally Blank

VECC INTERROGATORY 7

Issue 4.5 Is the IESO's MRP Business Case appropriate?

4.5-VECC-7

INTERROGATORY

Reference: Exhibit G-2-1, Attachment 1 MRP Energy Stream Business Case, page 48

The IESO looked to other system operators who have completed significant market change programs to determine if they had any insight into participant costs that might be leveraged. For various reasons, including the nature of the market change programs completed and different market participation models, it was found that market participant costs varied considerably. As a result, the IESO has no effective way of estimating potential cost or saving impacts to stakeholders at this time. The IESO cannot track Market Participant costs and therefore these impacts have not been included as part of the costs in the business case.

a) Having completed a review of other operators please provide what were the low and high cost scenarios to market participants arising from a significant change to market rules such as those contemplated by the MRP?

b) Please confirm (or correct) that the summarized cost-benefit analysis shown at page 62 of the G-2-1, Attachment 1, does not include any stakeholder costs.

c) Why should the cost-benefit analysis of the MRP not be considered seriously deficient if it does not incorporate an estimate of the cost of the proposed market rule changes to market stakeholders?

RESPONSE

a) The IESO's comment on page 48 of the MRP Business Case was based on the Brattle report which described the variation of such costs but did not point out specific high and low values.

b) Confirmed.

c) The analysis uses conservative assumptions and many potential benefits have not been quantified. Overall, the IESO is confident that the realized value of the Market Renewal Program (MRP) will exceed the benefits that are presented in the MRP Business Case. Further, market participant readiness is a key component for the Market Renewal Program (MRP) go-live. Planning is underway for the market participant readiness component of the MRP's implementation phase. The IESO will work with stakeholders through the Technical Advisory Group, and outline training and support plans to work on market participant readiness. These planning activities will inform timing and any potential impacts to schedule and budget.

Page Intentionally Blank

TAB 11

Ontario Energy Board Act, 1998

S.O. 1998, CHAPTER 15
SCHEDULE B

CURRENT Consolidation period: December 4, 2024 - e-Laws currency date (December 31, 2024)

Last amendment: 2024, c. 26, Sched. 3, s. 3.

Legislative History

Table of contents

PART I
GENERAL

Board objectives, electricity

1 (1) The Board, in carrying out its responsibilities under this or any other Act in relation to electricity, shall be guided by the following objectives:

1. To inform consumers and protect their interests with respect to prices and the adequacy, reliability and quality of electricity service.

1.1 Repealed: 2019, c. 6, Sched. 2, s. 1.

2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.

3. To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.

4. To facilitate innovation in the electricity sector.

5. Repealed: 2020, c. 36, Sched. 34, s. 1.

2004, c. 23, Sched. B, s. 1; 2009, c. 12, Sched. D, s. 1; 2015, c. 29, s. 7; 2019, c. 6, Sched. 2, s. 1; 2020, c. 36, Sched. 34, s. 1.

(2) Repealed: 2016, c. 10, Sched. 2, s. 11.

v **Section Amendments with date in force (d/m/y)**

Board objectives, gas

2 The Board, in carrying out its responsibilities under this or any other Act in relation to gas, shall be guided by the following objectives:

1. To facilitate competition in the sale of gas to users.

2. To inform consumers and protect their interests with respect to prices and the reliability and quality of gas service.

3. To facilitate rational expansion of transmission and distribution systems.

4. To facilitate rational development and safe operation of gas storage.

5. To promote energy conservation and energy efficiency in accordance with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.

5.1 To facilitate the maintenance of a financially viable gas industry for the transmission, distribution and storage of gas.

6. To promote communication within the gas industry. 1998, c. 15, Sched. B, s. 2; 2002, c. 23, s. 4 (2); 2003, c. 3, s. 3; 2004, c. 23, Sched. B, s. 2; 2009, c. 12, Sched. D, s. 2; 2019, c. 6, Sched. 2, s. 2.

Section Amendments with date in force (d/m/y)

Board objectives

2.1 The Board, in exercising its powers and performing its duties under this or any other Act, shall be guided by the objective of facilitating the implementation of any directives issued under subsection 25.30 (2) of the *Electricity Act, 1998*. 2016, c. 10, Sched. 2, s. 12; 2024, c. 26, Sched. 1, s. 7.

Section Amendments with date in force (d/m/y)

Definitions

3 (1) In this Act,

"affiliate", with respect to a corporation, has the same meaning as in the *Business Corporations Act*; ("membre du même groupe")

"associate", where used to indicate a relationship with any person, means,

(a) any body corporate of which the person owns, directly or indirectly, voting securities carrying more than 50 per cent of the voting rights attached to all voting securities of the body corporate for the time being outstanding,

(b) any partner of that person,

(c) any trust or estate in which the person has a substantial beneficial interest or as to which the person serves as trustee or in a similar capacity,

(d) any relative of the person, including the person's spouse as defined in the *Business Corporations Act*, where the relative has the same home as the person, or

(e) any relative of the spouse, as defined in the *Business Corporations Act*, of the person, where the relative has the same home as the person; ("personne qui a un lien")

"Board" means the Ontario Energy Board; ("Commission")

"board of directors" means the board of directors of the Board set out under section 4.1; ("conseil d'administration")

"chief commissioner" means the commissioner who is chief commissioner under section 4.3; ("commissaire en chef")

"chief executive officer" means the chief executive officer under section 4.2; ("chef de la direction")

"commissioner" means a commissioner under section 4.3; ("commissaire")

"construct" means construct, reconstruct, relocate, enlarge or extend; ("construire")

"distribute", with respect to electricity, means to convey electricity at voltages of 50 kilovolts or less; ("distribuer")

"distribution system" means a system for distributing electricity, and includes any structures, equipment or other things used for that purpose; ("réseau de distribution")

"distributor" means a person who owns or operates a distribution system; ("distributeur")

"enforceable provision" means,

(a) a provision of this Act or the regulations,

(b) a provision of Part II of the *Energy Consumer Protection Act, 2010* or of the regulations made under it,

(c) a provision of Part III of the *Energy Consumer Protection Act, 2010* or of the regulations made under it,

(c.1) a provision of a regulation made under Part III.1 of the *Energy Consumer Protection Act, 2010*,

(c.2) a provision of the *Ontario Rebate for Electricity Consumers Act, 2016* or the regulations made under it,

(c.3) section 25.35.8 of the *Electricity Act, 1998* or a provision of a regulation made under that section,

(d) subsection 5 (4), (5), (6) or (7) or section 25.33, 25.36, 25.37, 26, 27, 28, 28.1, 29, 30.1, 31, 53.11, 53.13, 53.15, 53.16 or 53.18 of the *Electricity Act, 1998*, or any other provision of that Act that is prescribed by the regulations,

(e) regulations made under clause 114 (1.3) (f) or (h) of the *Electricity Act, 1998,*

(f) a condition of a licence issued under Part IV, V or V.1,

(g) a provision of the rules made under section 44 or a code issued under section 70.1,

(h) a provision of an order of the Board,

(i) a provision of an assurance of voluntary compliance that is given to the Board under section 112.7 or that was entered into under section 88.8 before that section was repealed, or

(j) a provision of any other Act or the regulations made under an Act, as may be prescribed by regulation; ("disposition exécutoire")

"fuel oil" means any liquid hydrocarbon within the meaning from time to time of the Canadian General Standards Board specification CAN/CGSB-3.2-M89 entitled FUEL OIL HEATING, CAN/CGSB-3.3-M89 entitled KEROSENE, CAN/CGSB-3.6-M90 entitled AUTOMOTIVE DIESEL FUEL or, when used for heating, cooking or lighting, within the meaning from time to time of CAN/CGSB-3.27-M89 entitled NAPHTHA FUEL; ("mazout")

"gas" means natural gas, substitute natural gas, synthetic gas, manufactured gas, propane-air gas or any mixture of any of them; ("gaz")

"gas distributor" means a person who delivers gas to a consumer and "distribute" and "distribution" have corresponding meanings; ("distributeur de gaz", "distribuer", "distribution")

"gas transmitter" means a person who carries gas by hydrocarbon transmission line, and "transmit" and "transmission" have corresponding meanings; ("transporteur de gaz", "transporter", "transport")

"generic hearing" means a hearing held under subsection 19 (4) to determine one or more matters pertaining to multiple persons or entities whose activities are regulated by the Board under this Act; ("audience générique")

"IESO" means the Independent Electricity System Operator established under the *Electricity Act, 1998*; ("SIERE")

"land" includes any interest in land; ("bien-fonds")

"manufactured gas" means any artificially produced fuel gas, except acetylene and any other gas used principally in welding or cutting metals; ("gaz manufacturé")

"members of the Board" means the individuals who compose the Board under subsection 4 (5); ("membres de la Commission")

"Minister" means the Minister of Energy or such other member of the Executive Council as may be assigned the administration of this Act under the *Executive Council Act*; ("ministre")

"oil" means crude oil, and includes any hydrocarbon that can be recovered in liquid form from a pool through a well; ("pétrole")

"pipe line" means a pipe that carries a hydrocarbon and includes every part of the pipe and adjunct thereto; ("pipeline")

"pool" means an underground accumulation of oil or natural gas or both, separated or appearing to be separated from any other such underground accumulation; ("gisement")

"producer" means a person who has the right to remove gas or oil from a well, and "produce" and "production" have corresponding meanings except when referring to documents or records; ("producteur", "produire", "production")

"propane" means a hydrocarbon consisting of 95 per cent or more of propane, propylene, butane or butylene, or any blend thereof; ("propane")

"rate" means a rate, charge or other consideration and includes a penalty for late payment; ("tarif")

"regulations" means the regulations made under this Act; ("règlements")

"renewable energy generation facility" has the same meaning as in the *Electricity Act, 1998*; ("installation de production d'énergie renouvelable")

"renewable energy source" has the same meaning as in the *Electricity Act, 1998*; ("source d'énergie renouvelable")

"smart grid" has the same meaning as in the *Electricity Act, 1998*; ("réseau intelligent")

"Smart Metering Entity" means the corporation incorporated, the limited partnership or the partnership formed or the entity designated pursuant to section 53.7 of the *Electricity*

Act, 1998; (“Entité responsable des compteurs intelligents”)

“smart metering initiative” means those policies of the Government of Ontario related to its decision to ensure Ontario electricity consumers are provided, over time, with smart meters; (“initiative des compteurs intelligents”)

“station” means a compressor station, a metering station, an odorizing station or a regulating station; (“station”)

“storage company” means a person engaged in the business of storing gas; (“compagnie de stockage”)

“suite meter” has the same meaning as in Part III of the *Energy Consumer Protection Act, 2010*; (“compteur individuel”)

“transmission system” means a system for transmitting electricity, and includes any structures, equipment or other things used for that purpose; (“réseau de transport”)

“transmit”, with respect to electricity, means to convey electricity at voltages of more than 50 kilovolts; (“transporter”)

“transmitter” means a person who owns or operates a transmission system; (“transporteur”)

“unit smart metering” has the same meaning as in Part III of the *Energy Consumer Protection Act, 2010*; (“activités liées aux compteurs intelligents d’unité”)

“unit smart meter provider” has the same meaning as in Part III of the *Energy Consumer Protection Act, 2010*; (“fournisseur de compteurs intelligents d’unité”)

“unit sub-metering” has the same meaning as in Part III of the *Energy Consumer Protection Act, 2010*; (“activités liées aux compteurs divisionnaires d’unité”)

“unit sub-meter provider” has the same meaning as in Part III of the *Energy Consumer Protection Act, 2010*; (“fournisseur de compteurs divisionnaires d’unité”)

"utility line" means a pipe line, a telephone, telegraph, electric power or water line, or any other line that supplies a service or commodity to the public; ("ligne de service public")

"voting security" has the same meaning as in the *Business Corporations Act*; ("valeur mobilière avec droit de vote")

"well" means a hole drilled into a geological formation of Cambrian or more recent age, except a hole where no gas or oil is encountered that is drilled for the production of fresh water or salt. ("puits") 1998, c. 15, Sched. B, s. 3; 1999, c. 6, s. 48; 2002, c. 1, Sched. B, s. 1; 2002, c. 23, s. 4 (3); 2003, c. 3, s. 4; 2005, c. 5, s. 51; 2006, c. 3, Sched. C, s. 1; 2009, c. 12, Sched. D, s. 3; 2010, c. 8, s. 38 (1); 2010, c. 26, Sched. 13, s. 17 (1); 2011, c. 9, Sched. 27, s. 34 (1); 2014, c. 7, Sched. 23, s. 1; 2016, c. 19, s. 17 (1); 2016, c. 23, s. 61; 2017, c. 2, Sched. 10, s. 2 (1); 2017, c. 34, Sched. 18, s. 3; 2018, c. 16, s. 7 (1); 2019, c. 6, Sched. 2, s. 3; 2020, c. 34, Sched. 14, s. 1; 2024, c. 10, s. 1; 2024, c. 26, Sched. 2, s. 1 (1); 2024, c. 26, Sched. 3, s. 3 (1).

Deemed code amendments

(2) A reference in this or any other Act to a code issued under section 70.1 includes a reference to amendments specified under section 70.4 that are deemed to have been issued under section 70.1, as applicable, except in the context of subsection 33 (1) or section 121. 2024, c. 26, Sched. 2, s. 1 (2).

Section Amendments with date in force (d/m/y)

PART II
THE BOARD

Ontario Energy Board

Board continued

4 (1) The Ontario Energy Board is continued as a corporation without share capital under the name Ontario Energy Board in English and Commission de l'énergie de l'Ontario in French. 2003, c. 3, s. 5 (2).

Powers

(2) The Board has the capacity and the rights, powers and privileges of a natural person for the purpose of exercising and performing its powers and duties under this or any other Act,

except as otherwise provided in this Act. 2003, c. 3, s. 5 (4).

Duties

(3) The Board shall perform the duties assigned to it under this or any other Act. 2003, c. 3, s. 5 (4).

Crown agency

(4) The Board is an agent of Her Majesty in right of Ontario, and its powers may be exercised only as an agent of Her Majesty. 2003, c. 3, s. 5 (4).

Composition of the Board

(5) The Board shall be composed of,

(a) a board of directors;

(b) a chief executive officer;

(c) commissioners, including a chief commissioner; and

(d) any other person or class of persons prescribed by the regulations, appointed in accordance with the regulations. 2019, c. 6, Sched. 2, s. 4.

Section Amendments with date in force (d/m/y)

Board of directors

4.1 (1) The board of directors shall manage and supervise the management of the Board's business and affairs, and perform such other duties as are assigned to the board of directors under this or any other Act. 2019, c. 6, Sched. 2, s. 5.

Composition

(2) The board of directors shall be composed of at least five and no more than 10 members appointed by the Lieutenant Governor in Council. 2019, c. 6, Sched. 2, s. 5.

Restriction on appointment

(3) A person who is a person or in a class of persons prescribed by the regulations is not eligible to be appointed as a director. 2019, c. 6, Sched. 2, s. 5; 2020, c. 36, Sched. 34, s. 2.

Term of initial appointment

(4) The first term of office of a person who is appointed to the board of directors shall not exceed two years. 2019, c. 6, Sched. 2, s. 5.

Reappointment

(5) A person appointed to the board of directors may be reappointed for one or more terms of up to three years each. 2019, c. 6, Sched. 2, s. 5.

Directors to be independent

(6) Each director shall hold office as an independent director and not as a representative of any class of persons. 2019, c. 6, Sched. 2, s. 5.

Director's duties

(7) Every director shall, in exercising his or her powers and performing his or her duties as a director,

(a) act honestly and in good faith in the best interests of the Board; and

(b) exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. 2019, c. 6, Sched. 2, s. 5.

Chair, vice-chair

(8) The Lieutenant Governor in Council shall appoint a chair, and may appoint a vice-chair, from among the members of the board of directors. 2019, c. 6, Sched. 2, s. 5.

Duties of chair

(9) The chair shall,

(a) oversee the efficient administration of the business of the board of directors;

(b) preside over meetings of the board of directors;

(c) be accountable to the Minister for the effective delivery of the Board's objectives;

(d) be accountable to the Minister for the independence of persons and entities hearing and determining matters within the Board's jurisdiction in their decision-making;

(e) perform such other duties as are assigned to the chair under this or any other Act. 2019, c. 6, Sched. 2, s. 5.

Term, chair and vice-chair

(10) The chair and vice-chair hold office for the term specified by the Lieutenant Governor in Council, which shall not exceed his or her term as a member of the board of directors. 2019, c. 6, Sched. 2, s. 5.

Chair may delegate to vice-chair

(11) The chair may in writing delegate any of his or her powers or duties as chair to the vice-chair, subject to any conditions or restrictions specified in the delegation. 2019, c. 6, Sched. 2, s. 5.

Acting chair

(12) The vice-chair may exercise the powers and perform the duties of the chair if the chair is absent or unable to act. 2019, c. 6, Sched. 2, s. 5.

Same

(13) If the chair is absent or unable to act and no vice-chair is available, the members present shall appoint an acting chair from among themselves. 2019, c. 6, Sched. 2, s. 5.

Quorum

(14) Subject to by-laws made under clause 4.10 (2) (f), a majority of the board of directors constitute a quorum. 2019, c. 6, Sched. 2, s. 5.

Committees

(15) The board of directors shall, in accordance with the by-laws made under section 4.10, establish an adjudication committee of the board of directors, and may, in accordance with those by-laws, establish any other committees of the board of directors. 2019, c. 6, Sched. 2, s. 5.

Adjudication committee

(16) The adjudication committee may require the chief commissioner to provide to it such information it specifies, in the time and manner it specifies, respecting the efficiency, timeliness and dependability of the hearing and determination of matters over which the Board has jurisdiction, and shall report the information to the board of directors. 2019, c. 6, Sched. 2, s. 5.

Exercise of Board powers, duties

(17) Except where this Act provides otherwise and subject to the regulations, the powers and duties of the Board, other than with respect to the hearing and determination of matters over which the Board has jurisdiction, may be exercised and shall be performed by the board of directors. 2019, c. 6, Sched. 2, s. 5.

No interference

(18) For greater certainty, no power given to the board of directors or a director under this or any other Act permits the board of directors or a director to interfere with or influence the hearing or determination of a matter over which the Board has jurisdiction. 2019, c. 6, Sched. 2, s. 5.

Delegation

(19) The board of directors may, subject to any conditions or restrictions the board of directors specifies and in accordance with the by-laws made under section 4.10,

(a) delegate any of its powers or duties to a committee of the board of directors or to one or more directors; and

(b) delegate any of its powers to manage the Board's business and affairs to one or more officers employed by the Board. 2019, c. 6, Sched. 2, s. 5.

Same, exception

(20) Despite subsection (19), the board of directors shall not delegate any of its powers or duties under sections 4.8 to 4.10 and any other provision prescribed by the regulations. 2019, c. 6, Sched. 2, s. 5.

Same, limitation

(21) Despite subsection (19), the board of directors may only delegate its powers or duties under subsection 26 (1) or section 26.1 to the chief executive officer. 2019, c. 6, Sched. 2, s. 5.

Transition, number of appointments

(22) Until the second anniversary of the day section 5 of Schedule 2 to the *Fixing the Hydro Mess Act, 2019* comes into force, the board of directors may be composed of as few as three members appointed by the Lieutenant Governor in Council, despite subsection (2). 2019, c. 6, Sched. 2, s. 5.

Section Amendments with date in force (d/m/y)

Chief executive officer

4.2 (1) The board of directors shall appoint a person to the position of chief executive officer of the Board. 2019, c. 6, Sched. 2, s. 5.

Duties of chief executive officer

(2) The chief executive officer shall be responsible for the efficient and effective management of the operations of the Board, and shall perform such other duties as are assigned to the chief executive officer under this or any other Act. 2019, c. 6, Sched. 2, s. 5.

Restriction on appointment

(3) A person who is a person or in a class of persons prescribed by the regulations is not eligible to be appointed as chief executive officer. 2019, c. 6, Sched. 2, s. 5; 2020, c. 36, Sched. 34, s. 3.

Not a director

(4) The chief executive officer is an officer of the Board and not a member of its board of directors. 2019, c. 6, Sched. 2, s. 5.

Participation

(5) The chief executive officer may attend and participate at any meeting of the board of directors, but shall not have a vote with respect to any matter to be decided at the meeting. 2019, c. 6, Sched. 2, s. 5.

Exception

(6) Despite subsection (5), the board of directors may exclude the chief executive officer from attending any meeting if a matter to be discussed at the meeting involves the position, performance or functions and duties of the chief executive officer. 2019, c. 6, Sched. 2, s. 5.

No interference

(7) For greater certainty, no power given to the chief executive officer under this or any other Act permits the chief executive officer to interfere with or influence the hearing or determination of a matter over which the Board has jurisdiction. 2019, c. 6, Sched. 2, s. 5.

Transition, appointment

(8) Until the second anniversary of the day section 5 of Schedule 2 to the *Fixing the Hydro Mess Act, 2019* comes into force, the appointment and any reappointment of a chief executive officer shall be by the Lieutenant Governor in Council, despite subsection (1). 2019, c. 6, Sched. 2, s. 5.

Same

(9) The term of a person who becomes chief executive officer under subsection (8) shall end no later than the second anniversary of the day section 5 of Schedule 2 to the *Fixing the Hydro Mess Act, 2019* comes into force. 2019, c. 6, Sched. 2, s. 5.

Section Amendments with date in force (d/m/y)

Commissioners and panels

Commissioners

4.3 (1) The board of directors shall, on the recommendation of the chief executive officer, appoint at least five commissioners for the hearing and determination of matters over which the Board has jurisdiction in accordance with this section. 2019, c. 6, Sched. 2, s. 5; 2021, c. 34, Sched. 18, s. 1 (1).

Restriction on appointment

(2) The following persons are not eligible to be appointed as a commissioner:

1. A person who has any material interest in or is a director, officer, employee or agent of,

    i. a market participant,

    ii. a generator, distributor, gas distributor, transmitter, gas transmitter, storage company, gas marketer or retailer,

    iii. a unit sub-meter provider,

    iv. the Smart Metering Entity,

v. a person who sells electricity or ancillary services through the IESO-administered markets or directly to another person who is not a consumer,

vi. an industry association that represents a person referred to in subparagraph i, ii, iii, iv or v,

vii. the IESO, or

viii. an affiliate of a person listed in subparagraph i, ii, iii, iv, v or vii.

2. Any person or class of persons prescribed by the regulations. 2020, c. 36, Sched. 34, s. 4.

Chief commissioner

(3) The board of directors shall, on the recommendation of the chief executive officer, appoint a commissioner to the position of chief commissioner. 2019, c. 6, Sched. 2, s. 5.

Fixed terms

(4) The appointment of a person to the position of commissioner under subsection (1) or chief commissioner under subsection (3) shall be for a fixed term, and may not be revoked without cause. 2019, c. 6, Sched. 2, s. 5.

Term of initial appointment

(5) The first term of office of a person who is appointed to the position of commissioner under subsection (1) or chief commissioner under subsection (3) shall not exceed two years. 2019, c. 6, Sched. 2, s. 5.

Reappointment

(6) A person appointed to the position of commissioner under subsection (1) or chief commissioner under subsection (3) may be reappointed for one or more terms of up to five years each. 2019, c. 6, Sched. 2, s. 5.

Non-application of *Labour Relations Act, 1995*

(6.1) The *Labour Relations Act, 1995* does not apply to commissioners. 2021, c. 34, Sched. 18, s. 1 (2).

Panels

(7) The chief commissioner may assign one or more commissioners to a panel. 2019, c. 6, Sched. 2, s. 5.

Exercise of Board jurisdiction over matters

(8) Except where this Act provides otherwise and subject to the regulations, the powers and duties of the Board with respect to the hearing and determination of matters over which it has jurisdiction may be exercised and shall be performed by panels of commissioners assigned for the purpose by the chief commissioner under subsection (7). 2019, c. 6, Sched. 2, s. 5.

Same

(9) For the purposes of subsection (8), a panel has all the jurisdiction of the Board. 2019, c. 6, Sched. 2, s. 5.

Same

(10) A commissioner assigned to a panel under subsection (8) shall not exercise any power or perform any duty of the Board except as a member of a panel to which he or she has been assigned. 2019, c. 6, Sched. 2, s. 5.

Duties of chief commissioner

(11) The chief commissioner shall,

(a) ensure the efficiency, timeliness and dependability of the hearing and determination of matters over which the Board has jurisdiction, including by directing and supervising commissioners with respect to efficiency, timeliness and dependability;

(b) report to the chief executive officer with respect to the efficiency, timeliness and dependability of the hearing and determination of matters over which the Board has jurisdiction;

(c) be responsible for the training of commissioners;

(d) perform such other duties as are assigned to the chief commissioner under this or any other Act. 2019, c. 6, Sched. 2, s. 5.

Deputy chief commissioner

(12) The chief commissioner may designate another commissioner as deputy chief commissioner, and the deputy chief commissioner may exercise the powers and perform the duties of the chief commissioner if the chief commissioner is absent or unable to act. 2019, c. 6, Sched. 2, s. 5.

Rules of practice and procedure

(13) The Board's authority to make rules under section 25.1 of the *Statutory Powers Procedure Act* governing practice and procedure respecting the hearing and determination of matters over which the Board has jurisdiction shall be exercised by the chief commissioner on behalf of the Board. 2019, c. 6, Sched. 2, s. 5.

Transition, existing members of the Board

(14) Despite subsection (1), any person who was a member of the Board immediately before the day section 5 of Schedule 2 to the *Fixing the Hydro Mess Act, 2019* came into force, other than the chair, becomes a commissioner on that day, and may continue to hold that position for the remainder of his or her term. 2019, c. 6, Sched. 2, s. 5.

Same

(15) A person who holds the position of commissioner under subsection (14) is entitled to the same remuneration to which he or she was entitled as a member of the Board immediately before the day referred to in that subsection. 2019, c. 6, Sched. 2, s. 5.

Transition, appointments

(16) Until the second anniversary of the day referred to in subsection (14), the appointment and any reappointment of the chief commissioner and of any commissioners shall be by the Lieutenant Governor in Council, despite subsections (1) and (3). 2019, c. 6, Sched. 2, s. 5.

Same

(17) For the purposes of subsection (16), the Lieutenant Governor in Council may appoint as chief commissioner a commissioner appointed under that subsection or a commissioner who holds the position under subsection (14). 2019, c. 6, Sched. 2, s. 5.

Same

(18) The term of a person appointed or reappointed as a commissioner or chief commissioner under subsection (16) shall end no later than the second anniversary of the

day section 5 of Schedule 2 to the *Fixing the Hydro Mess Act, 2019* comes into force. 2019, c. 6, Sched. 2, s. 5.

Section Amendments with date in force (d/m/y)

Market Surveillance Panel

4.3.1 (1) The Market Surveillance Panel established by the board of directors of the Independent Electricity Market Operator under subsection 13 (1) of the *Electricity Act, 1998* as it read on January 1, 2004 is continued as the Market Surveillance Panel of the Board. 2004, c. 23, Sched. B, s. 3.

Appointment

(2) The board of directors shall appoint the members of the Market Surveillance Panel. 2004, c. 23, Sched. B, s. 3; 2019, c. 6, Sched. 2, s. 28 (1).

Membership

(3) No person shall be appointed as a member of the Market Surveillance Panel if he or she has any material interest in a market participant or is a director, officer, employee or agent of,

(a) a generator, distributor, transmitter or retailer;

(b) a person who sells electricity or ancillary services through the IESO-administered markets or directly to another person who is not a consumer;

(c) a market participant;

(d) an industry association that represents a person referred to in clause (a), (b) or (c);

(e) Repealed: 2014, c. 7, Sched. 23, s. 2 (1).

(f) the IESO; or

(g) an affiliate of a person listed in clause (a), (b), (c) or (f). 2004, c. 23, Sched. B, s. 3; 2014, c. 7, Sched. 23, s. 2.

Same

(4) Subsection (3) applies only with respect to persons who first become members of the Market Surveillance Panel on or after the day subsection (3) comes into force. 2004, c. 23, Sched. B, s. 3.

Staff and assistance

(5) Subject to the by-laws made under section 4.10, the Market Surveillance Panel may use the services of employees of the Board and the IESO, with the consent of their employers, and of persons who have technical or professional expertise that the panel considers necessary. 2004, c. 23, Sched. B, s. 3.

Testimony

(6) A person who is a member of the Market Surveillance Panel or an employee of the IESO or the Board and who is acting on behalf of the Panel shall not be required in any civil proceeding to give testimony with respect to information obtained in the course of his or her duties. 2004, c. 23, Sched. B, s. 3.

Law enforcement information

(7) A record that contains information provided to or obtained by the Market Surveillance Panel and that is designated by the Panel as relating to activity in the IESO-administered markets or to the conduct of a market participant shall be deemed, for the purpose of section 14 of the *Freedom of Information and Protection of Privacy Act*, to be a record the disclosure of which could reasonably be expected to interfere with a law enforcement matter. 2004, c. 23, Sched. B, s. 3.

Confidential information relating to market participant

(8) A record that contains information provided to or obtained by the Market Surveillance Panel relating to a market participant and that is designated by the Panel as confidential or highly confidential shall be deemed, for the purpose of section 17 of the *Freedom of Information and Protection of Privacy Act*, to be a record that reveals a trade secret or scientific, technical, commercial, financial or labour relations information, supplied in confidence implicitly or explicitly, the disclosure of which could reasonably be expected to prejudice significantly the competitive position or interfere significantly with the contractual or other negotiations of a person, group of persons, or organization. 2004, c. 23, Sched. B, s. 3.

Regulations

(9) The Lieutenant Governor in Council may make regulations,

(a) prescribing a day on which the Market Surveillance Panel is dissolved and the Board commences to exercise the powers and perform the duties of the Panel under this or any other Act;

(b) governing the application, after the dissolution of the Panel, of any provision of this or any other Act that relates to the Market Surveillance Panel or its powers or duties. 2004, c. 23, Sched. B, s. 3.

Section Amendments with date in force (d/m/y)

Processes, stakeholder input

Electricity industry

4.4 (1) The Board shall establish one or more processes by which electricity consumers, distributors, generators, transmitters, any other persons who have an interest in the electricity industry and any other persons who may be prescribed by the regulations may provide advice and recommendations for consideration by the Board. 2024, c. 10, s. 2.

Gas industry

(2) The Board shall establish one or more processes by which gas consumers, gas distributors, gas transmitters, storage companies, any other persons who have an interest in the gas industry and any other persons who may be prescribed by the regulations may provide advice and recommendations for consideration by the Board. 2024, c. 10, s. 2.

Specified persons

(3) If the regulations so provide,

(a) a process under subsection (1) shall include such electricity consumers, distributors, generators, transmitters, other persons who have an interest in the electricity industry or prescribed persons as the regulations specify;

(b) a process under subsection (2) shall include such gas consumers, gas distributors, gas transmitters, storage companies, other persons who have an interest in the gas

industry or prescribed persons as the regulations specify. 2024, c. 10, s. 2.

Section Amendments with date in force (d/m/y)

Processes, representation of consumer and other interests

4.4.1 (1) The Board shall establish one or more processes by which the interests of electricity consumers, gas consumers and any other persons who may be prescribed by the regulations may be represented in proceedings before the Board, through advocacy and through any other modes of representation provided for by the Board. 2024, c. 10, s. 2.

Specified persons

(2) If the regulations so provide, a process under subsection (1) shall include such electricity consumers, gas consumers or prescribed persons as the regulations specify. 2024, c. 10, s. 2.

Section Amendments with date in force (d/m/y)

Fiscal year

4.5 The fiscal year of the Board begins on April 1. 2003, c. 3, s. 10.

Section Amendments with date in force (d/m/y)

Memorandum of understanding

4.6 (1) Every three years beginning with the Board's fiscal year in which subsection 7 (1) of Schedule 2 to the *Fixing the Hydro Mess Act, 2019* came into force, the chair of the board of directors, on behalf of the Board, and the Minister shall, in accordance with such directives as may be issued by the Management Board of Cabinet, enter into a memorandum of understanding setting out,

(a) the respective roles and responsibilities of the Minister, the chair and the board of directors;

(b) the accountability relationships between the chair, the board of directors and the Minister;

(c) limitations on the Board's powers to borrow and invest;

(d) the responsibility of the chair and the board of directors to provide the Minister with business plans, operational budgets and plans for proposed significant changes in the operations or activities of the Board;

(e) details of any obligations that require the board of directors to establish performance standards for the Board;

(f) any other matter required by a directive issued by the Management Board of Cabinet; and

(g) any other matter the parties consider necessary or appropriate. 2019, c. 6, Sched. 2, s. 6 (1).

Same

(2) The Board shall comply with the memorandum of understanding in exercising its powers and performing its duties under this Act, but the failure to do so does not affect the validity of any action taken by the Board or give rise to any rights or remedies by any person, other than rights or remedies provided by the memorandum of understanding. 2003, c. 3, s. 11.

Publication

(3) The board of directors shall publish the memorandum of understanding on the Board's website on the Internet as soon as practicable after the memorandum is entered into. 2003, c. 3, s. 11; 2019, c. 6, Sched. 2, s. 6 (2).

Section Amendments with date in force (d/m/y)

Minister's request for information

4.7 (1) The board of directors shall promptly give the Minister such information about the Board's activities, operations and financial affairs as the Minister requests. 2003, c. 3, s. 11; 2019, c. 6, Sched. 2, s. 28 (1).

Examination

(2) The Minister may designate a person to examine any financial or accounting procedures, activities or practices of the Board and report the results of the examination to the Minister. 2003, c. 3, s. 11.

Duty to assist, etc.

(3) The members and employees of the Board shall give the person designated by the Minister all the assistance and co-operation necessary to enable him or her to complete the examination. 2003, c. 3, s. 11.

---

v **Section Amendments with date in force (d/m/y)**

Financial statements

4.8 (1) The board of directors shall cause annual financial statements to be prepared for the Board in accordance with generally accepted accounting principles. 2019, c. 6, Sched. 2, s. 7 (1).

Same

(2) The financial statements must present the financial position, results of operations and changes in the financial position of the Board for its most recent fiscal year. 2003, c. 3, s. 11.

Auditors

(3) The board of directors shall appoint one or more auditors licensed under the *Public Accounting Act, 2004* to audit the financial statements of the Board for each fiscal year. 2003, c. 3, s. 11; 2004, c. 8, s. 46; 2019, c. 6, Sched. 2, s. 7 (2).

Auditor General

(4) The Auditor General may also audit the financial statements of the Board. 2003, c. 3, s. 11; 2004, c. 17, s. 32.

---

v **Section Amendments with date in force (d/m/y)**

Annual report

4.9 (1) The Board shall prepare an annual report, provide it to the Minister no later than 120 days after the end of the Board's fiscal year and make it available to the public. 2017, c. 34, Sched. 46, s. 33.

Same

(2) The Board shall comply with such directives as may be issued by the Management Board of Cabinet with respect to,

(a) the form and content of the annual report; and

(b) when and how to make it available to the public. 2017, c. 34, Sched. 46, s. 33.

Same

(3) In addition to any content specified under clause (2) (a), the annual report shall include,

(a) details of steps taken by the board of directors to simplify or streamline practices and procedures in relation to the Board's regulatory functions; and

(b) any other content the Minister requires. 2019, c. 6, Sched. 2, s. 8.

Section Amendments with date in force (d/m/y)

Tabling of annual report

4.9.1 The Minister shall table the Board's annual report in the Assembly no later than 30 days after determining that the annual report meets the requirements of section 4.9 and shall comply with such directives as may be issued by the Management Board of Cabinet with respect to when and how to make that determination. 2017, c. 34, Sched. 46, s. 33.

Section Amendments with date in force (d/m/y)

By-laws

4.10 (1) The board of directors may make by-laws regulating the business and affairs of the Board. 2019, c. 6, Sched. 2, s. 9.

Governance and structure by-laws

(2) Without limiting the generality of subsection (1), the board of directors shall ensure that the by-laws deal with matters of corporate governance and structure, including,

(a) the powers, duties and functions of the members of the Board and of the officers employed by the Board, including specifying the accountability relationship of the chief commissioner to the chief executive officer and other accountability relationships;

(b) the remuneration and benefits for the positions of commissioner and chief commissioner appointed by the board of directors;

(c) the circumstances in which a member of the Board ceases to hold office;

(d) procedures for the appointment and reappointment of the chief executive officer, the chief commissioner and other commissioners;

(e) the delegation of the board of directors' powers and duties under subsection 4.1 (19) and of the Board's powers and duties under section 6;

(f) the emergency circumstances in which the quorum of the board of directors is one member;

(g) the appointment of an auditor;

(h) the establishment, composition and functions of the adjudication committee and other committees of the board of directors;

(i) the establishment, composition and functions of panels of commissioners;

(j) the composition and functions of the Market Surveillance Panel and the appointment, removal and remuneration of members of the Market Surveillance Panel; and

(k) any other matter prescribed by the regulations. 2019, c. 6, Sched. 2, s. 9.

(3) Repealed: 2021, c. 34, Sched. 18, s. 2 (1).

Notice to Minister

(4) The board of directors shall deliver to the Minister a copy of every by-law passed by it. 2019, c. 6, Sched. 2, s. 9.

(5)-(7) Repealed: 2021, c. 34, Sched. 18, s. 2 (1).

Minister's review of certain by-laws

(8) Within 60 days after delivery of a by-law made under clause (2) (b) or (d), the Minister may approve, reject or return it to the board of directors for further consideration. 2019, c. 6, Sched. 2, s. 9; 2021, c. 34, Sched. 18, s. 2 (2).

Effect of approval

(9) A by-law made under clause (2) (b) or (d) that is approved by the Minister becomes effective on the date of the approval or on such later date as the by-law may provide. 2019, c. 6, Sched. 2, s. 9; 2021, c. 34, Sched. 18, s. 2 (2).

Effect of rejection

(10) A by-law made under clause (2) (b) or (d) that is rejected by the Minister does not become effective. 2019, c. 6, Sched. 2, s. 9; 2021, c. 34, Sched. 18, s. 2 (2).

Effect of return for further consideration

(11) A by-law made under clause (2) (b) or (d) that is returned to the board of directors for further consideration does not become effective until the board of directors returns it to the Minister and the Minister approves it. 2019, c. 6, Sched. 2, s. 9; 2021, c. 34, Sched. 18, s. 2 (2).

Expiry of review period

(12) If, within the 60-day period referred to in subsection (8), the Minister does not take a step under this section, the by-law becomes effective on the 75th day after it is delivered to the Minister or on such later date as the by-law may provide. 2019, c. 6, Sched. 2, s. 9; 2021, c. 34, Sched. 18, s. 2 (3).

Publication

(13) The board of directors shall publish every by-law made under subsection (2) on the Board's website as soon as practicable after the by-law becomes effective. 2019, c. 6, Sched. 2, s. 9.

Legislation Act, 2006, Part III

(14) Part III (Regulations) of the *Legislation Act, 2006* does not apply to by-laws made under subsection (2). 2019, c. 6, Sched. 2, s. 9.

Section Amendments with date in force (d/m/y)

Restrictions on Board powers

4.11 The Board shall not, without the approval of the Lieutenant Governor in Council,

(a) create a subsidiary;

(b) purchase or sell real property;

(c) borrow money, pledge, mortgage or hypothecate any of its property, or create or grant a security interest in any of its property;

(d) enter into a contract of a class prescribed by the regulations; or

(e) exercise other rights, powers or privileges under subsection 4 (2) that are prescribed by the regulations. 2003, c. 3, s. 12.

Section Amendments with date in force (d/m/y)

Purchases and loans by Province

4.12 (1) The Minister of Finance, on behalf of Ontario, may purchase securities of or make loans to the Board in such amounts, at such times and on such terms and conditions as the Lieutenant Governor in Council considers expedient. 2003, c. 3, s. 12.

Same

(2) The Minister of Finance may pay from the Consolidated Revenue Fund the money necessary for a purchase or loan made under subsection (1). 2003, c. 3, s. 12.

Section Amendments with date in force (d/m/y)

Authority re income

4.13 (1) Despite Part I of the *Financial Administration Act* and subject to subsection 26.1 (5), revenue from the exercise of a power conferred or the discharge of a duty imposed on the Board or the board of directors under this or any other Act, and the investments held by the Board, do not form part of the Consolidated Revenue Fund and, subject to this section, shall be applied to carrying out the powers conferred and duties imposed on the Board under this or any other Act. 2003, c. 3, s. 12; 2009, c. 12, Sched. D, s. 5; 2019, c. 6, Sched. 2, s. 28.

Same

(2) The revenue referred to in subsection (1) includes the following:

1. Fees payable under section 12.1.
2. Assessments payable under section 26.
3. Costs payable to the Board under section 30.
4. Administrative penalties payable under section 112.5. 2003, c. 3, s. 12.

Section Amendments with date in force (d/m/y)

Collection of personal information

4.14 The Board may collect personal information within the meaning of section 38 of the *Freedom of Information and Protection of Privacy Act* for the purpose of carrying out its duties and exercising its powers under this or any other Act. 2003, c. 3, s. 12.

Section Amendments with date in force (d/m/y)

Non-application of certain Acts

4.15 The *Not-for-Profit Corporations Act, 2010* and the *Corporations Information Act* do not apply with respect to the Board. 2003, c. 3, s. 12; 2017, c. 20, Sched. 8, s. 109.

Section Amendments with date in force (d/m/y)

Members and employees

4.16 (1) Repealed: 2006, c. 35, Sched. C, s. 98.

Not employees

(2) The members of the board of directors are not its employees, and shall not hold any other office in the Board or be employed by it in any other capacity. 2019, c. 6, Sched. 2, s. 10 (1).

Conflict of interest, indemnification

(3) Sections 132 (conflict of interest) and 136 (indemnification) of the *Business Corporations Act* apply with necessary modifications with respect to the Board as if the Minister were its sole shareholder and, for the purposes of section 136 of that Act, commissioners including the chief commissioner are deemed to be a director or officer of the Board. 2003, c. 3, s. 12; 2019, c. 6, Sched. 2, s. 10 (2).

Agreement for services

(4) The Board and a ministry of the Crown may enter into agreements for the provision by employees of the Crown of any service required by the Board to carry out its duties and powers, and the Board shall pay the agreed amount for services provided to it. 2003, c. 3, s. 12.

Section Amendments with date in force (d/m/y)

Registrar

5 The chief executive officer shall appoint a registrar of the Board from among the Board's employees. 2019, c. 6, Sched. 2, s. 11.

Section Amendments with date in force (d/m/y)

Delegation of Board's powers and duties

6 (1) Subject to the by-laws made under section 4.10 and to the approval of the chief executive officer, the chief commissioner may in writing delegate any power or duty of the Board that may be exercised or shall be performed under subsection 4.3 (8) to an employee of the Board who is not a member of the Board. 2019, c. 6, Sched. 2, s. 12 (1).

Exceptions

(2) Subsection (1) does not apply to the following powers and duties:

1. Hearing and determining an appeal under section 7 or a review under section 8.

2. The power to make an order against a person under section 112.3, 112.4 or 112.5, if the person gives notice requiring the Board to hold a hearing under section 112.2.

3. A power or duty prescribed by the regulations. 2019, c. 6, Sched. 2, s. 12 (1).

Conditions and restrictions

(3) A delegation under this section is subject to such conditions and restrictions as the chief commissioner may specify in writing. 2003, c. 3, s. 13; 2019, c. 6, Sched. 2, s. 12 (2).

No hearing

(4) An employee of the Board may exercise powers and duties that are delegated under this section without holding a hearing. 2003, c. 3, s. 13.

Statutory Powers Procedure Act

(5) If an employee of the Board holds a hearing pursuant to this section, the *Statutory Powers Procedure Act* applies to the same extent as if a panel of commissioners were holding the hearing. 2003, c. 3, s. 13; 2019, c. 6, Sched. 2, s. 12 (3).

Review by employee

(6) An employee of the Board who makes an order pursuant to this section may, within a reasonable time after the order is made and if he or she considers it advisable, review all or part of the order, and may confirm, vary or cancel the order. 2003, c. 3, s. 13.

Transfer to Board

(7) At any time before an employee of the Board makes an order in respect of a matter pursuant to this section, the chief commissioner may direct that the matter be transferred to the Board for determination. 2003, c. 3, s. 13; 2019, c. 6, Sched. 2, s. 12 (4).

Effect of employees' orders, etc.

(8) Anything done by an employee of the Board pursuant to this section shall be deemed, for the purpose of this or any other Act, to have been done by the Board. 2003, c. 3, s. 13.

Application of s. 33

(9) Despite subsection (8), section 33 and subsection 38 (4) do not apply to an order made by an employee of the Board pursuant to this section. 2003, c. 3, s. 13; 2009, c. 33, Sched. 2, s. 51 (1).

Section Amendments with date in force (d/m/y)

Appeal from delegated function

7 (1) A person directly affected by an order made by an employee of the Board pursuant to section 6 may, within 15 days after receiving notice of the order, appeal the order to the Board. 2003, c. 3, s. 13.

Exception

(2) Subsection (1) does not apply to,

(a) a person who did not make submissions to the employee after being given notice of the opportunity to do so; or

(b) a person who did not give notice requiring the Board to hold a hearing under section 112.2, in the case of an order made by the employee under section 112.3, 112.4 or 112.5. 2003, c. 3, s. 13.

Parties

(3) The parties to the appeal are:

1. The appellant.
2. The applicant, if the order is made in a proceeding commenced by an application.
3. The employee who made the order.
4. Any other person added as a party by the Board. 2003, c. 3, s. 13.

Powers of Board

(4) The Board may confirm, vary or cancel the order. 2003, c. 3, s. 13.

Stay

(5) An appeal under this section does not stay the order of the employee, unless the Board orders otherwise. 2003, c. 3, s. 13.

Section Amendments with date in force (d/m/y)

Review of delegated function

8 (1) The chief commissioner may, on his or her own motion, within 15 days after the making of an order by an employee of the Board pursuant to section 6, direct the Board to review the order. 2003, c. 3, s. 13; 2019, c. 6, Sched. 2, s. 13.

Parties

(2) The parties to the review are:

1. Every person directly affected by the order, including, if the order is made in a proceeding commenced by an application, the applicant.

2. The employee who made the order.

3. Any other person added as a party by the Board. 2003, c. 3, s. 13.

Exception

(3) Despite paragraph 1 of subsection (2), a person is not a party to the review if the person did not make submissions to the employee after being given notice of the opportunity to do so. 2003, c. 3, s. 13.

Application of subss. 7 (4) and (5)

(4) Subsections 7 (4) and (5) apply, with necessary modifications, to a review under this section. 2003, c. 3, s. 13.

Section Amendments with date in force (d/m/y)

Power to administer oaths

9 The registrar of the Board and an inspector appointed under section 106 has, in carrying out his or her duties under this Act, the same powers as a commissioner for taking affidavits in Ontario. 2003, c. 3, s. 14; 2019, c. 6, Sched. 2, s. 29.

Section Amendments with date in force (d/m/y)

Not required to testify

10 Members of the Board and employees of the Board are not required to give testimony in any civil proceeding with regard to information obtained in the discharge of their official duties. 1998, c. 15, Sched. B, s. 10.

Liability

11 (1) No action or other civil proceeding shall be commenced against any of the following persons for any act done in good faith in the exercise or performance or the intended exercise or performance of a power or duty under any Act or regulation or for any neglect or default in the exercise or performance in good faith of such a power or duty:

1. A member of the Board.

2. An officer, employee or agent of the Board.

3. A member of the Market Surveillance Panel.

4. An officer, employee or agent of the IESO acting on behalf of the Market Surveillance Panel. 2004, c. 23, Sched. B, s. 6.

Same

(2) A member of the Board is not liable for an act, an omission, an obligation or a liability of the Board or its employees. 2003, c. 3, s. 15.

Crown liability

(3) Despite subsection 8 (3) of the *Crown Liability and Proceedings Act, 2019*, subsections (1) and (2) do not relieve the Crown of any liability to which it would otherwise be subject in respect of a tort committed by any person referred to in subsection (1) or (2). 2003, c. 3, s. 15; 2019, c. 7, Sched. 17, s. 132.

Section Amendments with date in force (d/m/y)

Fees and access to licences

12 (1)-(3) REPEALED: 2003, c. 3, s. 16.

Inspection

(4) The Board shall make all licences available for public inspection during normal business hours. 1998, c. 15, Sched. B, s. 12 (4).

∨ **Section Amendments with date in force (d/m/y)**

Fees

12.1 (1) The chief executive officer may set and charge fees for copies of Board orders, decisions, reasons, reports, recordings or other documents or things, including documents certified by a commissioner or the registrar of the Board. 2019, c. 6, Sched. 2, s. 14 (1).

Application and other fees

(2) The board of directors may set and charge licence fees, application fees and other fees relating to an application or appeal to the Board. 2003, c. 3, s. 17; 2019, c. 6, Sched. 2, s. 14 (2).

Classes

(3) The board of directors may establish different fees for different classes of persons and for different types of proceedings and types of licences. 2003, c. 3, s. 17; 2019, c. 6, Sched. 2, s. 14 (2).

Mandatory fees re gas marketers and retailers of electricity

(4) The board of directors shall, as of the time or times prescribed by regulation, set and charge fees for the licensing of gas marketers under section 48 and retailers of electricity under section 57. 2010, c. 8, s. 38 (2); 2019, c. 6, Sched. 2, s. 14 (2).

∨ **Section Amendments with date in force (d/m/y)**

Forms

13 The chief executive officer may,

(a) establish forms and require their use in connection with any matter relating to the Board; or

(b) approve forms or the content of the forms and require that any application, appeal or information submitted to the Board be in the approved form. 2003, c. 3, s. 18; 2019, c. 6, Sched. 2, s. 15.

Section Amendments with date in force (d/m/y)

Assistance

14 The Board may appoint persons having technical or special knowledge to assist the Board. 1998, c. 15, Sched. B, s. 14.

Orders and licences

15 (1) All orders made and licences issued by the Board shall be signed by a commissioner or the registrar of the Board. 2003, c. 3, s. 19; 2019, c. 6, Sched. 2, s. 16 (1).

Same

(2) Despite subsection (1), an order made or licence issued by the Board pursuant to section 6 may be signed by the employee who made the order or issued the licence. 2003, c. 3, s. 19.

Judicial notice

(3) An order or licence that purports to be signed by a person referred to in subsection (1) or (2) shall be judicially noticed without further proof. 2003, c. 3, s. 19.

Legislation Act, 2006, Part III

(4) Part III (Regulations) of the *Legislation Act, 2006* does not apply to the orders made or licences issued by the Board. 2003, c. 3, s. 19; 2006, c. 21, Sched. F, s. 136 (1).

Note: On a day to be named by proclamation of the Lieutenant Governor, subsection 15 (4) of the Act is repealed. (See: 2019, c. 6, Sched. 2, s. 16 (2))

Section Amendments with date in force (d/m/y)

16 Repealed: 2003, c. 3, s. 19.

Section Amendments with date in force (d/m/y)

17 Repealed: 2003, c. 3, s. 19.

Section Amendments with date in force (d/m/y)

Transfer of authority or licence

18 (1) No authority given by the Board under this or any other Act shall be transferred or assigned without leave of the Board. 1998, c. 15, Sched. B, s. 18 (1).

Same

(2) A licence issued under this Act is not transferable or assignable without leave of the Board. 1998, c. 15, Sched. B, s. 18 (2).

Board's powers, general

Power to determine law and fact

19 (1) The Board has in all matters within its jurisdiction authority to hear and determine all questions of law and of fact. 1998, c. 15, Sched. B, s. 19 (1).

Order

(2) The Board shall make any determination in a proceeding by order. 1998, c. 15, Sched. B, s. 19 (2); 2001, c. 9, Sched. F, s. 2 (1).

Reference

(3) If a proceeding before the Board is commenced by a reference to the Board by the Minister of Natural Resources, the Board shall proceed in accordance with the reference. 1998, c. 15, Sched. B, s. 19 (3).

Additional powers and duties

(4) The Board of its own motion may, and if so directed by the Minister under section 28 or 28.8 or otherwise under this or any other Act shall, determine any matter that under this Act or the regulations it may upon an application determine and in so doing the Board has and may exercise the same powers as upon an application. 1998, c. 15, Sched. B, s. 19 (4); 2024, c. 10, s. 3 (1).

Same

(4.1) Subsection (4) includes the determination of matters at a generic hearing. 2024, c. 10, s. 3 (2).

Exception

(5) Unless specifically provided otherwise, subsection (4) does not apply to any application under the *Electricity Act, 1998* or any other Act. 1998, c. 15, Sched. B, s. 19 (5).

Jurisdiction exclusive

(6) The Board has exclusive jurisdiction in all cases and in respect of all matters in which jurisdiction is conferred on it by this or any other Act. 1998, c. 15, Sched. B, s. 19 (6).

Section Amendments with date in force (d/m/y)

Powers, procedures applicable to all matters

20 Subject to any provision to the contrary in this or any other Act, the powers and procedures of the Board set out in this Part apply to all matters before the Board under this or any other Act. 1998, c. 15, Sched. B, s. 20.

Board's powers, miscellaneous

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. 1998, c. 15, Sched. B, s. 21 (1).

Hearing upon notice

(2) Subject to any provision to the contrary under this or any other Act, the Board shall not make an order under this or any other Act until it has held a hearing after giving notice in such manner and to such persons as the Board may direct. 1998, c. 15, Sched. B, s. 21 (2); 2021, c. 2, Sched. 2, s. 1.

(3) Repealed: 2000, c. 26, Sched. D, s. 2 (2).

No hearing

(4) Despite section 4.1 of the *Statutory Powers Procedure Act*, the Board may, in addition to its power under that section, dispose of a proceeding without a hearing if,

(a) no person requests a hearing within a reasonable time set by the Board after the Board gives notice of the right to request a hearing; or

(b) the Board determines that no person, other than the applicant, appellant or licence holder will be adversely affected in a material way by the outcome of the proceeding and the applicant, appellant or licence holder has consented to disposing of a proceeding without a hearing.

(c) Repealed: 2003, c. 3, s. 20 (1).

1998, c. 15, Sched. B, s. 21 (4); 2002, c. 1, Sched. B, s. 3; 2003, c. 3, s. 20 (1).

Consolidation of proceedings

(5) Despite subsection 9.1 (1) of the *Statutory Powers Procedure Act*, the Board may combine two or more proceedings or any part of them, or hear two or more proceedings at the same time, without the consent of the parties. 2003, c. 3, s. 20 (2).

Non-application

(6) Subsection 9.1 (3) of the *Statutory Powers Procedure Act* does not apply to proceedings before the Board. 1998, c. 15, Sched. B, s. 21 (6).

Use of same evidence

(6.1) Despite subsection 9.1 (5) of the *Statutory Powers Procedure Act*, the Board may treat evidence that is admitted in a proceeding as if it were also admitted in another proceeding that is heard at the same time, without the consent of the parties to the second-named proceeding. 2003, c. 3, s. 20 (3).

Interim orders

(7) The Board may make interim orders pending the final disposition of a matter before it. 1998, c. 15, Sched. B, s. 21 (7).

Section Amendments with date in force (d/m/y)

Liquidators, etc.

21.1 (1) None of the following prevent the exercise by the Board of any jurisdiction conferred by this or any other Act with respect to a regulated utility:

1. The fact that a liquidator, receiver, manager or other official of the regulated utility has been appointed by a court in Ontario.

2. The fact that a writ of sequestration has been issued in Ontario with respect to the regulated utility.

3. The fact that a person is managing or operating the regulated utility under the authority of a court in Ontario. 2017, c. 2, Sched. 10, s. 2 (2).

Obligations of liquidators, etc.

(2) A regulated utility interim official shall manage and operate the regulated utility in accordance with,

(a) this Act;

(b) any other Act, to the extent that it confers jurisdiction on the Board;

(c) any applicable licence, order or direction issued by the Board under this Act or an Act referred to in clause (b);

(d) any applicable rule made under section 44 or code issued under section 70.1; and

(e) any applicable assurance of voluntary compliance given to the Board under section 112.7. 2017, c. 2, Sched. 10, s. 2 (2).

Must obey Board

(3) A regulated utility interim official, and any person acting under a regulated utility interim official, shall obey all orders of the Board within its jurisdiction in respect of the regulated utility, and the Board may enforce its orders against the official or person even though the official or person is appointed by, or acts under the authority of, a court. 2017, c. 2, Sched. 10, s. 2 (2).

Definitions

(4) In this section,

"regulated utility" means,

(a) a gas distributor, gas transmitter or storage company whose rates are approved or fixed by the Board under section 36, and

(b) a distributor or transmitter whose rates are approved or fixed by the Board under section 78; ("service public réglementé")

"regulated utility interim official" means,

(a) a liquidator, receiver, manager or other official of a regulated utility who has been appointed by a court in Ontario,

(b) a person acting in respect of a regulated utility under the authority of a writ of sequestration that has been issued in Ontario, or

(c) a person who is managing or operating a regulated utility under the authority of a court in Ontario. ("agent intérimaire d'un service public réglementé") 2017, c. 2, Sched. 10, s. 2 (2).

Section Amendments with date in force (d/m/y)

---

22 REPEALED: 2021, c. 4, Sched. 6, s. 73 (1).

Section Amendments with date in force (d/m/y)

Final decision

22.1 (1) The Board shall issue an order that embodies its final decision in a proceeding within 60 days after making the final decision. 2003, c. 3, s. 21.

Validity of decision not affected

(2) Failure to comply with subsection (1) does not affect the validity of the Board's decision. 2003, c. 3, s. 21.

Section Amendments with date in force (d/m/y)

Conditions of orders

23 (1) The Board in making an order may impose such conditions as it considers proper, and an order may be general or particular in its application. 1998, c. 15, Sched. B, s. 23.

(2) Repealed: 2003, c. 3, s. 22.

Section Amendments with date in force (d/m/y)

Written reasons to be made available

24 All written reasons of the Board shall be kept by the registrar and be made available to any person upon payment of the required fee. 1998, c. 15, Sched. B, s. 24; 2003, c. 3, s. 23; 2019, c. 6, Sched. 2, s. 29.

Section Amendments with date in force (d/m/y)

Obedience to orders of Board a good defence

25 An order of the Board is a good and sufficient defence to any proceeding brought or taken against any person in so far as the act or omission that is the subject of the proceeding is in accordance with the order. 1998, c. 15, Sched. B, s. 25.

Assessment

26 (1) Subject to the regulations, the board of directors may assess those persons or classes of persons prescribed by regulation with respect to all expenses incurred and expenditures made by the Board in the exercise of any powers or duties under this or any other Act. 1998, c. 15, Sched. B, s. 26 (1) ; 2003, c. 3, s. 24; 2019, c. 6, Sched. 2, s. 28 (1).

Obligation to pay assessment

(2) Every person assessed under subsection (1) shall pay the amount assessed. 1998, c. 15, Sched. B, s. 26 (2).

Order to pay assessment

(3) If a person fails to pay an assessment made under subsection (1), the Board may, without a hearing, order that person to pay the assessment. 1998, c. 15, Sched. B, s. 26 (3).

Failure to pay

(4) If a licensee fails to pay an assessment in accordance with the order, the Board, without a hearing, may suspend or cancel that person's licence. 1998, c. 15, Sched. B, s. 26 (4).

Payment of full amount

(5) The Board may reinstate the licence of a person whose licence was suspended or cancelled under subsection (4) if the person pays all amounts owing under this section. 1998, c. 15, Sched. B, s. 26 (5).

Regulations

(6) The Lieutenant Governor in Council may make regulations,

(a) prescribing persons or classes of persons liable to pay an assessment under subsection (1);

(b) prescribing the frequency of the assessments;

(c) respecting the manner in which an assessment under this section is carried out;

(d) prescribing the amount of the assessment or the method of calculating the amount;

(e) prescribing the proportion of the assessment for which each person or class of persons is liable or a method of determining the proportion;

(f) prescribing such other matters relating to the carrying out of an assessment as the Lieutenant Governor in Council considers appropriate. 1998, c. 15, Sched. B, s. 26 (6).

Scope

(7) A regulation under this section may be general or particular in its application. 1998, c. 15, Sched. B, s. 26 (7).

Section Amendments with date in force (d/m/y)

Assessment, Ministry conservation programs, etc.

26.1 (1) Subject to the regulations, the Board shall assess the following persons or classes of persons, as prescribed by regulation, with respect to the expenses incurred and expenditures made by the Ministry of Energy in respect of its energy conservation programs or renewable energy programs provided under this Act, the *Ministry of Energy Act, 2011* or any other Act:

1. In respect of consumers in their service areas, gas distributors and licensed distributors.

2. The IESO.

3. Any other person prescribed by regulation. 2009, c. 12, Sched. D, s. 6; 2011, c. 9, Sched. 27, s. 34 (2); 2018, c. 16, s. 7 (2).

Assessments, collection by gas distributors and licensed distributors

(2) Gas distributors and licensed distributors may collect the amounts assessed under subsection (1) from the consumers or classes of consumers as are prescribed by regulation and in the manner prescribed by regulation. 2009, c. 12, Sched. D, s. 6.

Assessments, IESO

(3) The IESO may collect the amounts assessed under subsection (1) from market participants or classes of market participants as are prescribed by regulation and in the manner prescribed by regulation. 2009, c. 12, Sched. D, s. 6.

Assessment, amount and timing

(4) For the purposes of subsection (1), the Board shall assess the amount prescribed by regulation within the time prescribed by regulation in accordance with the methods or rules prescribed by regulation. 2009, c. 12, Sched. D, s. 6.

Assessment, obligation to pay

(5) Every person assessed under subsection (1) shall pay the amount assessed in accordance with the Board's assessment by remitting the amount to the Minister of Finance. 2009, c. 12, Sched. D, s. 6.

Failure to pay

(6) If a person fails to pay an assessment made under subsection (1), the Board may, without a hearing, order the person to pay the assessment. 2009, c. 12, Sched. D, s. 6.

Reporting

(7) Persons referred to in subsection (1) shall report such information in such manner and at such times to the Board or to the Minister as is prescribed by regulation. 2009, c. 12, Sched. D, s. 6.

Regulations

(8) The Lieutenant Governor in Council may make regulations,

(a) governing assessments under this section, including,

(i) prescribing the amount to be assessed or the amounts to be assessed against each person, or class of person liable to pay an assessment or the method of calculating the amount or amounts, and

(ii) prescribing the time within which the assessments must occur;

(b) prescribing persons or classes of persons liable to pay an assessment under subsection (1);

(c) prescribing the frequency of the assessments;

(d) respecting the manner by which an assessment under this section is carried out;

(e) prescribing the proportion of the assessment for which each person or class of persons is liable or a method of determining the proportion;

(f) with respect to subsection (7), prescribing the time at which such reports must be made or submitted, the manner by which such reports must be made or submitted, and governing the information to be provided, including the manner in which such information is presented or provided;

(g) prescribing such other matters relating to the carrying out of an assessment as the Lieutenant Governor in Council considers appropriate. 2009, c. 12, Sched. D, s. 6.

Section Amendments with date in force (d/m/y)

Special purposes

26.2 (1) For the purpose of the *Financial Administration Act*, all amounts collected under section 26.1 relating to assessments paid shall be deemed to be money paid to Ontario for the special purposes set out in subsection (2). 2009, c. 12, Sched. D, s. 6.

Same

(2) The following are the special purposes for which amounts collected under section 26.1 relating to assessments are paid to Ontario:

1. To fund conservation or renewable energy programs aimed at decreasing the consumption of two or more of the following fuels:

   i. natural gas,

   ii. electricity,

   iii. propane,

   iv. oil,

   v. coal, and

   vi. wood.

2. To fund conservation or renewable energy programs aimed at causing consumers of fuel to change from one or more of the fuels listed in paragraph 1 to any other fuel or fuels listed in that paragraph.

3. To fund conservation or renewable energy programs aimed at decreasing peak electricity demand, while increasing or decreasing the consumption of another type of fuel.

4. To fund research and development or other engineering or scientific activities aimed at furthering the conservation or the efficient use of fuels.

5. To fund conservation or renewable energy programs aimed at a specific geographical, social, income or other sector of Ontario.

6. To reimburse the Province for expenditures it incurs for any of the above purposes. 2009, c. 12, Sched. D, s. 6.

Special Purpose Conservation and Renewable Energy Fund

(3) The Minister of Finance shall maintain in the Public Accounts an account to be known as the Ministry of Energy Special Purpose Conservation and Renewable Energy Fund in which shall be recorded all receipts and disbursements of public money under this section. 2009, c. 12, Sched. D, s. 6; 2011, c. 9, Sched. 27, s. 34 (3).

Non-interest bearing account

(4) The balances from time to time in the account do not bear interest. 2009, c. 12, Sched. D, s. 6.

Interpretation

(5) For the purposes of this section, the terms used in it that are not defined in this Act but that are defined in section 1 of the *Financial Administration Act* have the meanings provided in that Act. 2009, c. 12, Sched. D, s. 6.

Section Amendments with date in force (d/m/y)

Policy directives

27 (1) The Minister may issue, and the Board shall implement, policy directives that have been approved by the Lieutenant Governor in Council concerning general policy and the objectives to be pursued by the Board. 1998, c. 15, Sched. B, s. 27 (1).

Publication

(2) A policy directive issued under this section shall be published in *The Ontario Gazette*. 1998, c. 15, Sched. B, s. 27 (2).

Conservation directives

27.1 (1) The Minister may issue, and the Board shall implement, directives that have been approved by the Lieutenant Governor in Council that require the Board to take steps specified in the directives to promote energy conservation, energy efficiency, load management or the use of cleaner energy sources, including alternative and renewable energy sources. 2002, c. 23, s. 4 (4).

Publication

(2) A directive issued under this section shall be published in *The Ontario Gazette*. 2002, c. 23, s. 4 (4).

Section Amendments with date in force (d/m/y)

Directives re conservation and demand management targets

27.2 (1) The Minister may issue, and the Board shall implement, directives that have been approved by the Lieutenant Governor in Council that require the Board to take steps specified in the directive to establish conservation and demand management targets to be met by distributors and other licensees. 2009, c. 12, Sched. D, s. 7.

Directives, specified targets

(2) To promote conservation and demand management, a directive may require the Board to specify, as a condition of a licence, the conservation targets associated with those specified in the directive, and the targets shall be apportioned by the Board between distributors and other licensees in accordance with the directive. 2009, c. 12, Sched. D, s. 7.

Same

(3) A directive made under subsection (2) may require the IESO to provide information to the Board or to the Ministry about the conservation targets referred to in subsection (2) or the contracts referred to in subsection (5). 2009, c. 12, Sched. D, s. 7; 2014, c. 7, Sched. 23, s. 3 (1).

Directives re distributors

(4) Subject to subsection (7), a directive may require the Board to specify, as a condition of a licence, that a distributor may meet, at its discretion, any portion of its conservation target by seeking the approval of the Board for the conservation and demand management programs to be offered in its service area. 2009, c. 12, Sched. D, s. 7.

Directives, contracting with the IESO

(5) A directive may require the Board to specify, as a condition of a licence, that a distributor meet, at its discretion, any portion of its conservation target by contracting with the IESO to meet the target through province-wide programs offered by the IESO. 2014, c. 7, Sched. 23, s. 3 (2).

Public reporting

(6) To promote a culture of conservation and demand management, a directive may require the Board to specify, as a condition of a licence, that the licensee make public, by such means and at such time as specified in the directive, the steps that the licensee has taken to

meet its targets and the results that have been achieved in meeting those targets. 2009, c. 12, Sched. D, s. 7.

Hearings

(7) A directive may specify whether the Board is to hold a hearing, the circumstances under which a hearing may or may not be held and, if a hearing is to be held, the type of hearing to be held. 2009, c. 12, Sched. D, s. 7.

Publication

(8) A directive issued under this section shall be published in *The Ontario Gazette*. 2009, c. 12, Sched. D, s. 7.

Section Amendments with date in force (d/m/y)

Directives re: market rules, conditions

28 (1) In order to address the abuse or possible abuse of market power in the electricity sector, the Minister may issue, and the Board shall implement, directives that have been approved by the Lieutenant Governor in Council concerning market rules made under section 32 of the *Electricity Act, 1998* and existing or proposed licence conditions. 1998, c. 15, Sched. B, s. 28 (1).

Hearing

(2) A directive issued under subsection (1) may require the Board to hold a hearing or not to hold a hearing. 1998, c. 15, Sched. B, s. 28 (2).

Licence condition directives

28.1 (1) The Minister may issue, and the Board shall implement, directives that have been approved by the Lieutenant Governor in Council that require the Board, in the manner specified in the directives, to amend conditions in licences issued by the Board that relate to the directive issued to the Board pursuant to an order of the Lieutenant Governor in Council that was dated March 24, 1999 and is available on request from the Minister. 2002, c. 23, s. 4 (5).

No hearing

(2) The Board shall amend the conditions as required by a directive without holding a hearing. 2002, c. 23, s. 4 (5).

Section Amendments with date in force (d/m/y)

Directives re: commodity risk

28.2 The Minister may issue, and the Board shall implement, directives approved by the Lieutenant Governor in Council directing the Board to take such steps or develop such processes as may be required by the directive to address risks or liabilities associated with customer billing and payment cycles in respect of the cost of electricity at the retail and at the wholesale levels and risks or liabilities associated with non-payment or default by a consumer or retailer. 2004, c. 23, Sched. B, s. 7.

Section Amendments with date in force (d/m/y)

Directives re smart metering initiative

28.3 (1) The Minister may issue, and the Board shall implement, directives approved by the Lieutenant Governor in Council relating to the government's smart metering initiative. 2006, c. 3, Sched. C, s. 2.

Directives re licence conditions

(2) The directives may require the Board, in the manner specified in the directives, to amend conditions in licences issued by the Board that relate to the Smart Metering Entity, distributors, retailers and transmitters or licences issued pursuant to section 57, including the following:

1. Conditions granting the exclusive right to the Smart Metering Entity to carry out any or all of its objects set out in section 53.8 of the *Electricity Act, 1998*.

2. Conditions granting the exclusive right to store information and data derived from smart meters to the Smart Metering Entity, including conditions in respect of the manner in which the information and data is stored.

3. Conditions providing for performance standards to be achieved by the Smart Metering Entity.

4. Conditions identifying arrangements and agreements, including procurement, service or operating arrangements or agreements, to be entered into by the Smart Metering

Entity, distributors, transmitters, retailers or other persons and providing that the arrangements or agreements must contain specific conditions, restrictions, criteria or requirements relating to the arrangements or agreements.

5. Conditions providing for circumstances in which the Smart Metering Entity shall provide a person with access to information and data relating to consumers' consumption or use of electricity collected pursuant to paragraph 2 of section 53.8 of the *Electricity Act, 1998, including conditions relating to the protection of privacy.*

6. Conditions providing the Smart Metering Entity with the authority to conduct its metering activities in relation to the distribution of gas.

7. Conditions providing the Minister with exclusive authority to approve the base design, requirements, specifications and performance standards for smart meters, metering equipment, systems and technology and associated equipment, systems and technologies or classes of smart meters, equipment, systems and technology to be installed for prescribed classes of property and prescribed classes of consumers.

8. After a date prescribed by regulation made under the *Electricity Act, 1998*, conditions providing the Board with exclusive authority to approve the base design, requirements, specifications and performance standards for smart meters, metering equipment, systems and technology and associated equipment, systems and technologies or classes of smart meters, equipment, systems and technology to be installed for prescribed classes of property and prescribed classes of consumers. 2006, c. 3, Sched. C, s. 2.

Directives re amending conditions in licences

(3) A directive may require the Board, in the manner specified in the directive, to amend conditions in licences granted to the Smart Metering Entity, distributors, transmitters, retailers or others granting the Smart Metering Entity exclusive jurisdiction in Ontario with respect to some or all of the activities it is authorized to undertake under Part IV.2 of the *Electricity Act, 1998*. 2006, c. 3, Sched. C, s. 2.

Publication

(4) A directive issued under this section shall be published in *The Ontario Gazette*. 2006, c. 3, Sched. C, s. 2.

No hearing

(5) The Board shall amend the conditions as required by a directive without holding a hearing. 2006, c. 3, Sched. C, s. 2.

Section Amendments with date in force (d/m/y)

Directives re regulatory and accounting treatment of costs

28.4 The Minister may issue, and the Board shall implement, directives approved by the Lieutenant Governor in Council in respect of the regulatory and accounting treatment of costs in orders made under section 78 and associated with meters owned before January 1, 2006 to ensure that distributors, transmitters, retailers or other persons are not financially disadvantaged by the implementation of the smart metering initiative. 2006, c. 3, Sched. C, s. 2.

Section Amendments with date in force (d/m/y)

Directives, smart grid

28.5 (1) The Minister may issue, and the Board shall implement directives, approved by the Lieutenant Governor in Council, requiring the Board to take such steps as are specified in the directive relating to the establishment, implementation or promotion of a smart grid for Ontario. 2009, c. 12, Sched. D, s. 8.

Hearings

(2) A directive may specify whether the Board is to hold a hearing and the circumstances under which a hearing may or may not be held. 2009, c. 12, Sched. D, s. 8.

Publication

(3) A directive issued under this section shall be published in *The Ontario Gazette*. 2009, c. 12, Sched. D, s. 8.

Section Amendments with date in force (d/m/y)

Directives, connections

28.6 (1) The Minister may issue, and the Board shall implement directives, approved by the Lieutenant Governor in Council, requiring the Board to take such steps as are specified in the directive relating to the connection of renewable energy generation facilities to a transmitter's transmission system or a distributor's distribution system. 2009, c. 12, Sched. D, s. 8.

Directives, transmission and distribution systems

(2) A directive issued under subsection (1) may require the Board to amend the licence conditions of distributors, transmitters and other licensees to take the actions specified in the directive in relation to their transmission systems, distribution systems or other associated systems, including enhancing, re-enforcing or expanding their transmission systems, distribution systems or other associated systems. 2009, c. 12, Sched. D, s. 8; 2016, c. 10, Sched. 2, s. 13.

Hearings

(3) A directive may specify whether the Board is to hold a hearing and the circumstances under which a hearing may or may not be held. 2009, c. 12, Sched. D, s. 8.

(4) Repealed: 2020, c. 36, Sched. 34, s. 5.

Section Amendments with date in force (d/m/y)

Directives, transmission systems

28.6.1 (1) The Minister may issue, and the Board shall implement directives, approved by the Lieutenant Governor in Council, requiring the Board to take such steps as are specified in the directive relating to the construction, expansion or re-enforcement of transmission systems. 2016, c. 10, Sched. 2, s. 14.

Same

(2) Subsections 28.6 (2) and (3) apply with necessary modifications in respect of directives issued under subsection (1). 2016, c. 10, Sched. 2, s. 14.

Section Amendments with date in force (d/m/y)

Directives, gas marketers and electricity retailers

28.7 (1) The Minister may issue, and the Board shall implement, directives that have been approved by the Lieutenant Governor in Council in relation to the marketing of gas and the retailing of electricity in Ontario. 2010, c. 8, s. 38 (3).

Same

(2) A directive issued under subsection (1) may require the Board to take steps specified in the directive to promote fairness, efficiency and transparency in the retail market for gas and for electricity in Ontario or in respect of any activity associated with the marketing of gas or the retailing of electricity within Ontario. 2010, c. 8, s. 38 (3).

Same

(3) A directive may require the Board to amend licences referred to in section 48 in respect of gas marketers or under section 57 in respect of retailers of electricity and may require the Board to amend all licences so issued or to amend specific licences of specified licensees. 2010, c. 8, s. 38 (3).

Licence conditions

(4) The directives may require the Board, in the manner specified in the directives, to amend conditions in licences issued by the Board that relate to gas marketers or retailers of electricity, including the following:

1. Conditions regarding the operations and management and business practices of a gas marketer or retailer of electricity, including but not limited to the conduct of employees, agents or third parties acting on behalf of the gas marketer or retailer of electricity.

2. Activities, conduct or practices that must, may or may not be undertaken by a gas marketer or retailer of electricity, its employees, agents or third parties acting on behalf of the gas marketer or the retailer of electricity.

3. Conditions requiring or imposing standards that are required to be met by a gas marketer or retailer of electricity or its employees, agents or third parties acting on behalf of the gas marketer or retailer of electricity, including standards related to,

    i. education, training, certification and communications,

ii. business practices,

iii. performance standards,

iv. background verifications and assessments as required under paragraph 6,

v. record keeping,

vi. contracting, including standards related to contracting with certain specified classes of vulnerable consumers, and

vii. such other matters as may be specified in the directive.

4. Conditions requiring a gas marketer or retailer of electricity or its employees, agents or third parties acting on behalf of the gas marketer or retailer of electricity to provide such information orally or in writing to a consumer or a member of a class of consumers specified in the directive, the Board or the Ministry or to such other person or entity as may be specified in the directive, in the circumstances specified in the directive and within such time or times as may be specified in the directive.

5. Conditions requiring a gas marketer or retailer of electricity to meet criteria or requirements related to identification as specified in the directive, including criteria or requirements related to the identification credentials or badges or other forms of identification provided to its employees, agents or third parties acting on behalf of the gas marketer or retailer of electricity as may be specified in the directive.

6. Conditions requiring a gas marketer or retailer of electricity to meet specific criteria and requirements related to background verification and assessment of its employees, agents or third parties acting on behalf of the gas marketer or retailer of electricity, including the requirement to establish a process or processes to conduct the verifications and assessments, and the criteria and requirements may include the time or times at which the verifications and assessments must be performed.

7. Conditions requiring a gas marketer or retailer of electricity to take the following steps or do the following things in respect of its employees, agents or third parties acting on behalf of the gas marketer or retailer of electricity:

i. To establish a process or to follow or adhere to a process or processes as are prescribed by regulation or are approved by an order of the Board, for the following activities in respect of its employees, agents or third parties acting on behalf of the gas marketer or retailer of electricity:

A. licensing, including renewal, suspension and cancellation of licences,

B. bonding and insurance,

C. examination for credentials, certificates, accreditations or designations,

D. the creation of codes of conduct, best practices and policies,

E. requirements in relation to independence from or permissible investment in or association with the gas marketer or retailer of electricity or another licensee, and

F. such other matters as may be specified in the directive.

ii. To conduct, at such times as may be specified in the directive, the activities referred to in this section in relation to each of its employees, agents or third parties acting on behalf of the gas marketer or retailer of electricity.

iii. To ensure that its employees, agents or third parties acting on behalf of the gas marketer or retailer of electricity adhere to the process or processes referred to in this section and, in particular, obtain any specified credentials, accreditations or designations referred to in this section by such time or times as may be specified in the directive.

8. Conditions identifying provisions which must be included in any arrangements or agreements, including arrangements or agreements relating to the marketing of gas or the retailing of electricity with specified classes of consumers, entered into by the gas marketer or retailer of electricity or third parties acting on behalf of the gas marketer or retailer of electricity and such conditions may specify or provide that the arrangements or agreements must contain specific conditions, restrictions, criteria or requirements relating to the arrangements or agreements. 2010, c. 8, s. 38 (3).

Verification

(5) For the purposes of the verification of a contract required under Part II of the *Energy Consumer Protection Act, 2010*, a directive,

(a) may require the Board to prepare specified information, including preparing the information in languages specified in the directive, and to do so within the time specified in the directive; and

(b) may require that the Board require that gas marketers or retailers of electricity or specified classes of them,

(i) use the information in the manner specified in the directive, and

(ii) take such steps as may be specified in the directive to ensure that persons engaged by them in activities related to verification use the information in the manner specified in the directive. 2010, c. 8, s. 38 (3).

Audit and investigation

(6) A directive issued under this section may require the Board to,

(a) exercise its authority under Part V.1 to audit the records and information of the gas marketer or retailer of electricity specified in the directive, in such manner as is specified in the directive;

(b) exercise its authority under Part VII to inspect the activities or conduct of the gas marketers or retailers of electricity or the classes of gas marketers or retailers of electricity, as are specified in the directive, in relation to compliance with this Act or its regulations;

(c) exercise its authority under Part VII to undertake random inspections of the activities or conduct, as are specified in the directive, of the gas marketers or retailers of electricity specified in the directive, in relation to compliance with this Act or its regulations;

(d) exercise its authority under Part VII.0.1 to investigate the activities or conduct or the classes of activities or conduct, as are specified in the directive, of gas marketers or retailers of electricity generally or of the classes of gas marketers or retailers of

electricity as are specified in the directive, in relation to compliance with this Act or its regulations;

(e) exercise its authority under Part VII.0.1 to investigate the number or percentage, as is specified in the directive, of complaints received by the Board against gas marketers or retailers of electricity and reasonably considered by the Board to have merit, in relation to compliance with this Act or its regulations. 2010, c. 8, s. 38 (3).

Publication

(7) A directive issued under this section shall be published in *The Ontario Gazette*. 2010, c. 8, s. 38 (3).

No hearing

(8) The Board shall amend the conditions as required by a directive without holding a hearing. 2010, c. 8, s. 38 (3).

Section Amendments with date in force (d/m/y)

Directives, requirement to hold generic hearing (natural gas, electricity)

28.8 (1) In this section,

"ongoing proceeding" means, in respect of a proceeding before the Board, a proceeding in which the Board has not yet made a final order. 2024, c. 10, s. 4.

Same

(2) The Minister may issue, and the Board shall implement, directives that have been approved by the Lieutenant Governor in Council requiring the Board to hold a generic hearing to determine any matter respecting natural gas or electricity over which it has jurisdiction that the directives specify. 2024, c. 10, s. 4.

Same

(3) A directive issued under subsection (2) may specify,

(a) timelines for conducting the hearing;

(b) the manner in which the hearing may or must be conducted;

(c) matters, information or documents, including documents written or issued by the Government or by a minister or ministry of the Crown, that the Board must consider in conducting the hearing and making its determination; and

(d) any other matter respecting the hearing or its conduct that the Minister considers appropriate. 2024, c. 10, s. 4.

Exception

(4) Subsection (2) does not apply with respect to a matter if, at the time the directive would be issued, fewer than two years have elapsed since the matter was determined by a final order of the Board, regardless of whether the order was appealed. 2024, c. 10, s. 4.

Application to ongoing proceedings

(5) Subsection (2) may apply with respect to a matter that is the subject of an ongoing proceeding before the Board. 2024, c. 10, s. 4.

Same, effect

(6) If a directive is issued respecting a matter that is the subject of an ongoing proceeding before the Board,

(a) the Board shall not make any order in the ongoing proceeding with respect to the matter, and shall sever the matter from the ongoing proceeding to the extent possible; and

(b) except as provided under clause (a), the ongoing proceeding shall continue to the extent possible. 2024, c. 10, s. 4.

Procedural fairness does not apply

(7) Neither the issuance or approval of a directive under this section nor any action taken by the Board to implement or comply with it is subject to any duty of procedural fairness, including any requirement to provide notice, reasons or an opportunity to make submissions. 2024, c. 10, s. 4.

Same

(8) Subsection (7) applies despite the *Statutory Powers Procedure Act* and any other law. 2024, c. 10, s. 4.

Conflict

(9) In the event of a conflict between a directive under this section and the *Statutory Powers Procedure Act*, the rules made by the Board under section 25.1 of that Act or an order of the Board or other instrument or document made or issued under this Act, the directive prevails to the extent of the conflict. 2024, c. 10, s. 4.

Publication

(10) A directive issued under this section shall be published in *The Ontario Gazette*. 2024, c. 10, s. 4.

Not a regulation

(11) For greater certainty, Part III (Regulations) of the *Legislation Act, 2006* does not apply to directives issued under this section. 2024, c. 10, s. 4.

Section Amendments with date in force (d/m/y)

Refrain from exercising power

29 (1) On an application or in a proceeding, the Board shall make a determination to refrain, in whole or part, from exercising any power or performing any duty under this Act if it finds as a question of fact that a licensee, person, product, class of products, service or class of services is or will be subject to competition sufficient to protect the public interest. 1998, c. 15, Sched. B, s. 29 (1).

Scope

(2) Subsection (1) applies to the exercise of any power or the performance of any duty of the Board in relation to,

(a) any matter before the Board;

(b) any licensee;

(c) any person who is subject to this Act;

(d) any person selling, transmitting, distributing or storing gas; or

(e) any product or class of products supplied or service or class of services rendered within the province by a licensee or a person who is subject to this Act. 1998, c. 15, Sched. B, s. 29 (2).

Where determination made

(3) For greater certainty, where the Board makes a determination to refrain in whole or in part from the exercise of any power or the performance of any duty under this Act, and does so refrain, nothing in this Act limits the application of the *Competition Act* (Canada) to those matters with respect to which the Board refrains. 1998, c. 15, Sched. B, s. 29 (3).

Notice

(4) Where the Board makes a determination under this section, it shall promptly give notice of that fact to the Minister. 1998, c. 15, Sched. B, s. 29 (4).

Costs

30 (1) The Board may order a person to pay all or part of a person's costs of participating in a proceeding before the Board, a notice and comment process under section 45 or 70.2 or any other consultation process initiated by the Board. 2004, c. 23, Sched. B, s. 8.

Same

(2) The Board may make an interim or final order that provides,

(a) by whom and to whom any costs are to be paid;

(b) the amount of any costs to be paid or by whom any costs are to be assessed and allowed; and

(c) when any costs are to be paid. 2003, c. 3, s. 25 (1).

Rules

(3) The rules governing practice and procedure that are made under section 25.1 of the *Statutory Powers Procedure Act* may prescribe a scale under which costs shall be assessed. 2003, c. 3, s. 25 (1).

Inclusion of Board costs

(4) The costs may include the costs of the Board, regard being had to the time and expenses of the Board. 1998, c. 15, Sched. B, s. 30 (4).

Considerations not limited

(5) In awarding costs, the Board is not limited to the considerations that govern awards of costs in any court. 1998, c. 15, Sched. B, s. 30 (5).

Application

(6) This section applies despite section 17.1 of the *Statutory Powers Procedure Act*. 2003, c. 3, s. 25 (2).

---

v **Section Amendments with date in force (d/m/y)**

---

31 (1) REPEALED: 2002, c. 1, Sched. B, s. 5.

(2) REPEALED: 2003, c. 3, s. 26.

---

v **Section Amendments with date in force (d/m/y)**

Stated case

32 (1) The Board may, at the request of the Lieutenant Governor in Council or of its own motion or upon the motion of any party to proceedings before the Board and upon such security being given as it directs, state a case in writing for the opinion of the Divisional Court upon any question that is a question of law within the jurisdiction of the Board. 1998, c. 15, Sched. B, s. 32 (1); 2003, c. 3, s. 27.

Same

(2) The Divisional Court shall hear and determine the stated case and remit it to the Board with its opinion. 1998, c. 15, Sched. B, s. 32 (2).

---

v **Section Amendments with date in force (d/m/y)**

Appeal to Divisional Court

33 (1) An appeal lies to the Divisional Court from,

(a) an order of the Board;

(b) the making of a rule under section 44; or

(c) the issuance of a code under section 70.1. 2003, c. 3, s. 28 (1).

Nature of appeal, timing

(2) An appeal may be made only upon a question of law or jurisdiction and must be commenced not later than 30 days after the making of the order or rule or the issuance of the code. 1998, c. 15, Sched. B, s. 33 (2); 2003, c. 3, s. 28 (2).

Board may be heard

(3) The Board is entitled to be heard by counsel upon the argument of an appeal. 1998, c. 15, Sched. B, s. 33 (3).

Board to act on court's opinion

(4) The Divisional Court shall certify its opinion to the Board and the Board shall make an order in accordance with the opinion, but the order shall not be retroactive in its effect. 1998, c. 15, Sched. B, s. 33 (4).

Board not liable for costs

(5) The Board, or any member of the Board, is not liable for costs in connection with any appeal under this section. 1998, c. 15, Sched. B, s. 33 (5).

Order to take effect despite appeal

(6) Subject to subsection (7), every order made by the Board takes effect at the time prescribed in the order, and its operation is not stayed by an appeal, unless the Board orders otherwise. 2006, c. 33, Sched. X, s. 1.

Court may stay the order

(7) The Divisional Court may, on an appeal of an order made by the Board,

(a) stay the operation of the order; or

(b) set aside a stay of the operation of the order that was ordered by the Board under subsection (6). 2006, c. 33, Sched. X, s. 1.

Section Amendments with date in force (d/m/y)

No petition to Lieutenant Governor in Council

Definition

34 (1) In this section,

"old section 34" means this section as it read immediately before the day the *Good Government Act, 2009* received Royal Assent. 2009, c. 33, Sched. 2, s. 51 (2).

Not subject to petition

(2) Every order, rule or code of the Board that is the subject of a petition filed under the old section 34 that is not disposed of or withdrawn before the day the *Good Government Act, 2009* receives Royal Assent is deemed not to be subject to petition to the Lieutenant Governor in Council, and shall not be considered or continue to be considered, as the case may be, by the Lieutenant Governor in Council. 2009, c. 33, Sched. 2, s. 51 (2).

Same

(3) Every order, rule or code of the Board that may be the subject of a petition under the old section 34 is deemed not to be subject to petition to the Lieutenant Governor in Council, and shall not be considered by the Lieutenant Governor in Council. 2009, c. 33, Sched. 2, s. 51 (2).

No effect on validity

(4) Nothing in this section affects the validity of an order, rule or code of the Board that, but for subsection 51 (2) of Schedule 2 to the *Good Government Act, 2009*, was or could have been the subject of a petition filed under the old section 34. 2009, c. 33, Sched. 2, s. 51 (2).

Section Amendments with date in force (d/m/y)

Question referred to Board

35 The Minister may require the Board to examine, report and advise on any question respecting energy. 1998, c. 15, Sched. B, s. 35.

PART III
GAS REGULATION

Order of Board required

36 (1) No gas transmitter, gas distributor or storage company shall sell gas or charge for the transmission, distribution or storage of gas except in accordance with an order of the Board, which is not bound by the terms of any contract. 1998, c. 15, Sched. B, s. 36 (1).

Order of Board re Smart Metering Entity

(1.1) Neither the Smart Metering Entity nor any other person licensed to do so shall conduct activities relating to the metering of gas except in accordance with an order of the Board, which is not bound by the terms of any contract. 2006, c. 3, Sched. C, s. 3.

Order re: rates

(2) The Board may make orders approving or fixing just and reasonable rates for the sale of gas by gas transmitters, gas distributors and storage companies, and for the transmission, distribution and storage of gas. 1998, c. 15, Sched. B, s. 36 (2).

Power of Board

(3) In approving or fixing just and reasonable rates, the Board may adopt any method or technique that it considers appropriate. 1998, c. 15, Sched. B, s. 36 (3).

Limitation

(3.1) In approving or fixing just and reasonable rates for the sale, transmission or distribution of gas, the Board shall not include any of the following amounts:

1. Any penalties or fines a gas transmitter or gas distributor is required to pay under an Act, except as otherwise provided by the regulations.

2. Any other amounts or classes of amounts a gas transmitter or gas distributor is required to pay that are prescribed by the regulations made by the Minister under subsection 127 (8). 2023, c. 9, Sched. 24, s. 1.

Contents of order

(4) An order under this section may include conditions, classifications or practices applicable to the sale, transmission, distribution or storage of gas, including rules respecting the calculation of rates. 1998, c. 15, Sched. B, s. 36 (4).

Deferral or variance accounts

(4.1) If a gas distributor has a deferral or variance account that relates to the commodity of gas, the Board shall, from time to time, or as prescribed by the regulations, make an order under this section that determines whether and how amounts recorded in the account shall be reflected in rates. 2017, c. 2, Sched. 10, s. 2 (3).

Same

(4.2) If a gas distributor has a deferral or variance account that does not relate to the commodity of gas, the Board shall, from time to time, or as prescribed by the regulations, make an order under this section that determines whether and how amounts recorded in the account shall be reflected in rates. 2017, c. 2, Sched. 10, s. 2 (3).

Same

(4.3) An order that determines whether and how amounts recorded in a deferral or variance account shall be reflected in rates shall be made in accordance with the regulations. 2003, c. 3, s. 30.

Same

(4.4) If an order that determines whether and how amounts recorded in a deferral or variance account shall be reflected in rates is made after the time required by subsection (4.1) or (4.2) and the delay is due in whole or in part to the conduct of a gas distributor, the Board may reduce the amount that is reflected in rates. 2003, c. 3, s. 30.

Same

(4.5) If an amount recorded in a deferral or variance account of a gas distributor is reflected in rates, the Board shall consider the appropriate number of billing periods over which the amount shall be divided in order to mitigate the impact on consumers. 2003, c. 3, s. 30.

Fixing other rates

(5) Upon an application for an order approving or fixing rates, the Board may, if it is not satisfied that the rates applied for are just and reasonable, fix such other rates as it finds to be just and reasonable. 1998, c. 15, Sched. B, s. 36 (5).

Burden of proof

(6) Subject to subsection (7), in an application with respect to rates for the sale, transmission, distribution or storage of gas, the burden of proof is on the applicant. 1998, c. 15, Sched. B, s. 36 (6).

Order, motion of Board or at request of Minister

(7) If the Board of its own motion, or upon the request of the Minister, commences a proceeding to determine whether any of the rates for the sale, transmission, distribution or storage of gas by any gas transmitter, gas distributor or storage company are just and reasonable, the Board shall make an order under subsection (2) and the burden of establishing that the rates are just and reasonable is on the gas transmitter, gas distributor or storage company, as the case may be. 1998, c. 15, Sched. B, s. 36 (7).

Exception

(8) This section does not apply to a municipality or municipal public utility commission transmitting or distributing gas under the *Public Utilities Act* on the day before this section comes into force. 1998, c. 15, Sched. B, s. 36 (8).

Section Amendments with date in force (d/m/y)

Revenue horizon (natural gas)

36.0.1 (1) In this section,

"consumer" means a person who uses natural gas in Ontario for the person's own consumption; ("consommateur")

"natural gas distribution system" means a system for distributing natural gas in Ontario by hydrocarbon line, as defined in Part VI, and includes any structures, equipment or other things used for that purpose; ("réseau de distribution de gaz naturel")

"revenue horizon" means the number of years of presumed revenue that is used for the purposes of section 36 in determining,

(a) the economic feasibility of,

(i) a new consumer connection to the natural gas distribution system, or

(ii) an increase in the capacity of the natural gas distribution system, and

(b) the amount, if any, of a contribution in aid of construction required from a consumer in relation to a connection or increase described in clause (a). ("horizon de

revenu") 2024, c. 10, s. 5 (1).

Mandated revenue horizon

(2) The revenue horizon for the purposes of section 36 shall be the number of years specified by the regulations, except as otherwise provided by this section. 2024, c. 10, s. 5 (1).

Board may be required to make determination

(3) If the regulations so provide, the Board shall hold a hearing to determine revenue horizons for the purposes of section 36, in accordance with the regulations. 2024, c. 10, s. 5 (1).

Same

(4) Regulations made for the purposes of subsection (3) may provide for,

(a) timelines for conducting the hearing;

(b) the manner in which the hearing may or must be conducted, including requiring that it be conducted as a generic hearing;

(c) matters, information or documents, including documents written or issued by the Government or by a minister or ministry of the Crown, that the Board must consider in conducting the hearing and making its determination; and

(d) any other matter respecting the hearing or its conduct that the Lieutenant Governor in Council considers appropriate. 2024, c. 10, s. 5 (1).

Board determination prevails

(5) If the Board determines a revenue horizon for a period under subsection (3), that revenue horizon applies for the period instead of the revenue horizon specified by the regulations. 2024, c. 10, s. 5 (1).

Board to implement

(6) The Board shall take such steps under this Act as are necessary to implement the revenue horizon set out in subsection (2) or, if applicable, determined under subsection (3). 2024, c. 10, s. 5 (1).

Limitation

(7) The Board shall not make any determinations respecting revenue horizons for the purposes of section 36, except as provided by regulations made for the purposes of subsection (3). 2024, c. 10, s. 5 (1).

Same

(8) The Minister shall not issue a directive under section 28.8 respecting the determination of revenue horizons for the purposes of section 36. 2024, c. 10, s. 5 (1).

Procedural fairness does not apply

(9) No action taken by the Board to implement or comply with a regulation made under this section is subject to any duty of procedural fairness, including any requirement to provide notice, reasons or an opportunity to make submissions, despite the *Statutory Powers Procedure Act* or any other law. 2024, c. 10, s. 5 (1).

Same

(10) For greater certainty, nothing about the making of a regulation under this section, or the circumstances in which it is made, shall be interpreted as imposing a duty of procedural fairness on the exercise of a regulation-making authority. 2024, c. 10, s. 5 (1).

Conflict

(11) In the event of a conflict between a regulation made under this section and the *Statutory Powers Procedure Act*, the rules made by the Board under section 25.1 of that Act or an order of the Board or other instrument or document made or issued under this Act, the regulation prevails to the extent of the conflict. 2024, c. 10, s. 5 (1).

Same

(12) Subsection (11) does not apply with respect to an order of the Board made before December 21, 2023. 2024, c. 10, s. 5 (1).

Regulations

(13) The Lieutenant Governor in Council may make regulations for the purposes of this section,

(a) specifying numbers of years for the purposes of subsection (2), including, for greater certainty, specifying different numbers with respect to different classes of consumers;

(b) requiring and governing a hearing under subsection (3). 2024, c. 10, s. 5 (1).

Note: On January 1, 2029 or an earlier day to be named by proclamation of the Lieutenant Governor, section 36.0.1 of the Act, as enacted by subsection (1), is repealed. (See: 2024, c. 10, s. 5 (2))

Section Amendments with date in force (d/m/y)

Gas storage areas

36.1 (1) The Board may by order,

(a) designate an area as a gas storage area for the purposes of this Act; or

(b) amend or revoke a designation made under clause (a). 2001, c. 9, Sched. F, s. 2 (2).

Transition

(2) Every area that was designated by regulation as a gas storage area on the day before this section came into force shall be deemed to have been designated under clause (1) (a) as a gas storage area on the day the regulation came into force. 2001, c. 9, Sched. F, s. 2 (2).

Section Amendments with date in force (d/m/y)

Rate protection — expansion of natural gas distribution systems

Definition

36.2 (1) In this section,

"qualifying investment" means an investment that satisfies the prescribed criteria. 2018, c. 15, s. 1.

Board to provide rate protection

(2) The Board, in approving just and reasonable rates for a gas distributor, shall provide rate protection for consumers or prescribed classes of consumers with respect to costs incurred by the gas distributor in making a qualifying investment for the purpose of providing access to a natural gas distribution system to those consumers by reducing the rates that would otherwise apply in accordance with the prescribed rules. 2018, c. 15, s. 1.

Compensation

(3) A gas distributor is entitled to be compensated for lost revenue resulting from the rate reduction provided under subsection (2). 2018, c. 15, s. 1.

Liability

(4) All consumers, or such classes of consumers as are prescribed, are required, in accordance with the regulations, to contribute towards the amount of any compensation required under subsection (3). 2018, c. 15, s. 1.

Information, etc.

(5) If provided for in the regulations, the Board, gas distributors and other prescribed persons or entities shall provide such information and reports to the Ministry of Energy, Northern Development and Mines and to one another as are necessary to facilitate the implementation, administration, funding and delivery of the rate protection or of anything else provided for in this section. 2018, c. 15, s. 1.

Regulations

(6) The Lieutenant Governor in Council may make regulations,

(a) prescribing criteria for the purposes of the definition of "qualifying investment" in subsection (1);

(b) prescribing the consumers or classes of consumers eligible for rate protection under this section;

(c) prescribing rules for the calculation of the amount of the rate reduction;

(d) prescribing maximum amounts of the total annual value of rate protection that may be provided under this section;

(e) prescribing classes of consumers for the purposes of subsection (4);

(f) providing that certain classes of consumers are required to contribute towards the amount of compensation only in respect of certain gas distributors;

(g) prescribing rules respecting the amounts that must be collected to compensate gas distributors, including rules,

(i) respecting the calculation of those amounts,

(ii) establishing the time and manner of collection,

(iii) requiring the amounts to be paid in instalments and requiring the payment of interest or penalties on late payments,

(iv) prescribing methods of ensuring that the amounts required cannot be bypassed, and

(v) respecting the distribution of the amounts collected;

(h) respecting the use of money collected in excess of the amount required to compensate gas distributors;

(i) prescribing the powers and duties of the Board in relation to the calculation of amounts to be collected and the time and manner of collection and distribution;

(j) providing for and governing the provision of information and reports under subsection (5);

(k) prescribing persons or entities for the purposes of subsection (5);

(l) requiring a gas distributor, the Board or other persons or entities to make or receive payments in respect of rate protection under this section, including prescribing the circumstances in which such payments are to be made and received;

(m) governing invoices issued to consumers who are members of a class of consumers prescribed for the purposes of subsection (2) or (4) in respect of rate protection under this section, including,

(i) prescribing information that must or may be included on or with the invoices,

(ii) prescribing requirements that the invoices must meet,

(iii) prescribing the form of the invoice, including prescribing different requirements and forms, and

(iv) respecting the manner in which the invoices are to be provided to consumers;

(n) respecting any other matter that the Lieutenant Governor in Council considers necessary in relation to the rate protection. 2018, c. 15, s. 1.

Retroactivity

(7) A regulation made under this section is, if it so provides, effective with reference to a period before it is filed. 2018, c. 15, s. 1.

General or particular

(8) A regulation under this section may be general or particular in application and may prescribe different rules for different persons or classes of persons. 2018, c. 15, s. 1.

Section Amendments with date in force (d/m/y)

Prohibition, gas storage in undesignated areas

37 No person shall inject gas for storage into a geological formation unless the geological formation is within a designated gas storage area and unless, in the case of gas storage areas designated after January 31, 1962, authorization to do so has been obtained under section 38 or its predecessor. 1998, c. 15, Sched. B, s. 37; 2001, c. 9, Sched. F, s. 2 (3).

Section Amendments with date in force (d/m/y)

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. 1998, c. 15, Sched. B, s. 38 (1).

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. 1998, c. 15, Sched. B, s. 38 (2).

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. 1998, c. 15, Sched. B, s. 38 (3).

Appeal

(4) An appeal within the meaning of section 31 of the *Expropriations Act* lies from a determination of the Board under subsection (3) to the Divisional Court, in which case that section applies and section 33 of this Act does not apply. 1998, c. 15, Sched. B, s. 38 (4); 2003, c. 3, s. 31.

---

v **Section Amendments with date in force (d/m/y)**

Gas storage, surplus facilities and approval of agreements

Allocation of surplus storage facilities

39 (1) Upon the application of a gas transmitter or gas distributor, the Board by order may direct a storage company having storage capacity and facilities that are not in full use to provide all or part of the storage capacity and facilities for the applicant upon such conditions as may be determined by the Board. 1998, c. 15, Sched. B, s. 39 (1).

Gas storage agreements to be approved

(2) No storage company shall enter into an agreement or renew an agreement with any person for the storage of gas unless the Board, with or without a hearing has approved,

(a) the parties to the agreement or renewal;

(b) the period for which the agreement or renewal is to be in operation; and

(c) the storage that is the subject of the agreement or renewal. 1998, c. 15, Sched. B, s. 39 (2).

Referral to Board of application for well licence

40 (1) The Minister of Natural Resources shall refer to the Board every application for the granting of a licence relating to a well in a designated gas storage area, and the Board shall report to the Minister of Natural Resources on it. 1998, c. 15, Sched. B, s. 40 (1).

Hearing

(2) The Board may hold a hearing before reporting to the Minister if the applicant does not have authority to store gas in the area or, in the Board's opinion, the special circumstances of the case require a hearing. 1998, c. 15, Sched. B, s. 40 (2).

Copy of report to be sent to parties

(3) The Board shall send to each of the parties a copy of its report to the Minister made under subsection (1) within 10 days after submitting it to the Minister and such report shall be deemed to be an order of the Board within the meaning of section 34. 1998, c. 15, Sched. B, s. 40 (3).

Minister's decision

(4) The Minister of Natural Resources shall grant or refuse to grant the licence in accordance with the report. 1998, c. 15, Sched. B, s. 40 (4).

Allocation of market demand

41 The Board by order may allocate a just and equitable share of the market demands for gas or oil to the several sources from which the gas or oil is produced and to the several interests within a field or pool. 1998, c. 15, Sched. B, s. 41.

Duties of gas transmitters and distributors

Discontinuance of transmission or distribution

42 (1) Subject to the *Technical Standards and Safety Act, 2000* and the regulations made under that Act, and in the absence of an agreement to the contrary between the parties affected, no gas transmitter shall voluntarily discontinue transmitting gas to a gas distributor without leave of the Board. 1998, c. 15, Sched. B, s. 42 (1); 2002, c. 17, Sched. F, Table; 2003, c. 3, s. 32.

Duty of gas distributor

(2) Subject to the *Public Utilities Act*, the *Technical Standards and Safety Act, 2000* and the regulations made under the latter Act, sections 80, 81, 82 and 83 of the *Municipal Act, 2001* and sections 64, 65, 66 and 67 of the *City of Toronto Act, 2006*, a gas distributor shall provide

gas distribution services to any building along the line of any of the gas distributor's distribution pipe lines upon the request in writing of the owner, occupant or other person in charge of the building. 2006, c. 32, Sched. C, s. 42.

Order

(3) Upon application, the Board may order a gas transmitter, gas distributor or storage company to provide any gas sale, transmission, distribution or storage service or cease to provide any gas sale service. 1998, c. 15, Sched. B, s. 42 (3).

Restriction

(4) Despite subsection 19 (4), the Board may not commence a proceeding under subsection (3) on its own motion. 1998, c. 15, Sched. B, s. 42 (4).

Section Amendments with date in force (d/m/y)

Change in ownership or control of systems

Disposal

43 (1) No gas transmitter, gas distributor or storage company, without first obtaining from the Board an order granting leave, shall,

(a) sell, lease or otherwise dispose of its gas transmission, gas distribution or gas storage system as an entirety or substantially as an entirety;

(b) sell, lease or otherwise dispose of that part of a system described in paragraph (a) that is necessary in serving the public; or

(c) amalgamate with any other corporation. 1998, c. 15, Sched. B, s. 43 (1).

Same

(1.1) Subsection (1) does not apply with respect to a disposition of securities of a gas transmitter, gas distributor or storage company, or of a corporation that owns securities in a gas transmitter, gas distributor or storage company. 2003, c. 3, s. 33.

Acquisition of share control

(2) No person, without first obtaining an order from the Board granting leave, shall,

(a) acquire such number of voting securities of a gas transmitter, gas distributor or storage company that together with voting securities already held by such person and one or more affiliates or associates of that person, will in the aggregate exceed 20 per cent of the voting securities of a gas transmitter, gas distributor or storage company; or

(b) acquire control of any corporation that holds, directly or indirectly, more than 20 per cent of the voting securities of a gas transmitter, gas distributor or storage company if such voting securities constitute a significant asset of that corporation. 1998, c. 15, Sched. B, s. 43 (2).

Same

(2.1) Subsection (2) does not apply to,

(a) an underwriter (within the meaning of the *Securities Act*) who holds the voting securities solely for the purpose of distributing them to the public;

(b) any person or entity who is acting in relation to the voting securities solely in the capacity of an intermediary in the payment of funds or the delivery of securities or both in connection with trades in securities and who provides centralized facilities for the clearing of trades in securities; or

(c) any person or entity who holds the voting securities by way of security only. 2003, c. 3, s. 33.

Significant asset

(3) For the purpose of subsection (2),

(a) an asset is a significant asset if its value is 20 per cent or more of the aggregate book value of the total assets of a person, determined on a consolidated basis in accordance with generally accepted accounting principles; and

(b) "control", with respect to a corporation, has the same meaning as in the *Business Corporations Act*. 1998, c. 15, Sched. B, s. 43 (3).

Valuation of voting securities

(4) For the purpose of determining whether voting securities constitute a significant asset, the value of the voting securities shall be deemed to be,

(a) the market value of the securities if more than 20 per cent of the voting securities are publicly traded; and

(b) 115 per cent of the book value of the voting securities, as determined by the equity method of accounting, in all other cases. 1998, c. 15, Sched. B, s. 43 (4).

Mortgages

(5) This section does not apply to a mortgage or charge to secure any loan or indebtedness or to secure any bond, debenture or other evidence of indebtedness. 1998, c. 15, Sched. B, s. 43 (5).

Leave

(6) An application for leave under this section shall be made to the Board, which shall grant or refuse leave. 1998, c. 15, Sched. B, s. 43 (6).

Void agreement

(7) An amalgamation agreement between the corporations that propose to amalgamate is void if the Board refuses to grant leave under this section, even if the amalgamation agreement has been adopted in accordance with subsection 176 (4) of the *Business Corporations Act*. 1998, c. 15, Sched. B, s. 43 (7).

Void certificate

(8) A certificate of amalgamation endorsed by the director appointed under section 278 of the *Business Corporations Act* is void if it is endorsed before leave of the Board for the amalgamation is granted. 1998, c. 15, Sched. B, s. 43 (8).

Section Amendments with date in force (d/m/y)

Rules

44 (1) The chief executive officer may make rules,

(a) governing the conduct of a gas transmitter, gas distributor or storage company as such conduct relates to its affiliates;

(b) governing the conduct of a gas distributor as such conduct relates to any person,

(i) selling or offering to sell gas to a consumer,

(ii) acting as agent or broker for a seller of gas to a consumer, or

(iii) acting or offering to act as the agent or broker of a consumer in the purchase of gas;

(b.1) subject to subsections 42 (5) to (14), governing the conduct of a gas distributor as the conduct relates to,

(i) stopping the distribution of gas to a property, including the manner in which and the time within which the distribution stops or is to stop, and, with respect to a low-volume consumer as defined in section 47, periods during which the distribution may not be stopped,

(ii) the manner, timing and form in which the notice under subsection 42 (6) is to be provided to the person, and

(iii) the information to be included in the notice to the person;

(b.2) subject to the regulations, governing the manner and circumstances in which security is to be provided, including where security is to be provided or not to be provided by a gas consumer to a gas distributor and,

(i) the interest rate to be applied to amounts held on deposit and payable by the gas distributor to the consumer for the amounts,

(ii) the manner and time or times by which the amounts held on deposit may or must be paid or set-off against amounts otherwise due or payable by the consumer,

(iii) the circumstances in which security need not be provided or in which specific arrangements in respect of security may or must be provided by the gas distributor to the consumer, and

(iv) such other matters as the chief executive officer may determine in respect of security;

(b.3) relating to any matter in respect of invoices issued in respect of gas to consumers, including meeting such requirements as may be provided for by the chief executive officer or being in a form approved by the chief executive officer;

(c) governing the conduct of persons holding a licence issued under Part IV;

(c.1) relating to any matter, prescribed by regulation, in respect of gas marketers in relation to gas marketing, subject to any regulations made under this Act or under the *Energy Consumer Protection Act, 2010*;

(d) establishing conditions of access to transmission, distribution and storage services provided by a gas transmitter, gas distributor or storage company;

(e) establishing classes of gas transmitters, gas distributors and storage companies;

(f) requiring and providing for the making of returns, statements or reports by any class of gas transmitters, gas distributors or storage companies relating to the transmission, distribution, storage or sale of gas, in such form and containing such matters and verified in such manner as the rule may provide;

(g) requiring and providing for an affiliate of a gas transmitter, gas distributor or storage company to make returns, statements or reports relating to the transmission, distribution, storage or sale of gas by the gas transmitter, gas distributor or storage company of which it is the affiliate, in such form and containing such matters and verified in such manner as the rule may provide;

(h) establishing a uniform system of accounts applicable to any class of gas transmitters, gas distributors or storage companies;

(i) respecting any other matter prescribed by regulation. 1998, c. 15, Sched. B, s. 44 (1); 2010, c. 8, s. 38 (5); 2017, c. 1, s. 1 (1); 2019, c. 6, Sched. 2, s. 18 (1-3).

(1.1) Repealed: 2019, c. 6, Sched. 2, s. 18 (4).

Approval, etc., of Board

(2) A rule may require an approval, consent or determination of the Board, with or without a hearing, for any of the matters provided for in the rule. 2003, c. 3, s. 34 (2).

Incorporation by reference

(3) A rule authorized by this section may incorporate by reference, in whole or in part, any standard, procedure or guideline and may require compliance with any standard, procedure or guideline adopted. 1998, c. 15, Sched. B, s. 44 (3).

Scope

(4) A rule may be general or particular in its application and may be limited as to time or place or both. 1998, c. 15, Sched. B, s. 44 (4).

Conflict with *Public Utilities Act*

(4.1) In the event of a conflict between a rule made under subclause (1) (b.1) (i) and anything in section 59 of the *Public Utilities Act*, the rule prevails. 2017, c. 1, s. 1 (2); 2019, c. 6, Sched. 2, s. 18 (5).

Exemption

(5) A rule may authorize the Board to grant an exemption to it. 2000, c. 26, Sched. D, s. 2 (3).

Same

(6) An exemption or a removal of an exemption,

(a) may be granted or made in whole or in part; and

(b) may be granted or made subject to conditions or restrictions. 2000, c. 26, Sched. D, s. 2 (3).

Non-application

(7) Part III (Regulations) of the *Legislation Act, 2006* does not apply to the rules made under this section. 1998, c. 15, Sched. B, s. 44 (7); 2006, c. 21, Sched. F, s. 136 (1); 2019, c. 6, Sched. 2, s. 18 (6).

Note: On a day to be named by proclamation of the Lieutenant Governor, subsection 44 (7) of the Act is repealed. (See: 2019, c. 6, Sched. 2, s. 18 (7))

Section Amendments with date in force (d/m/y)

Proposed rules, notice and content

45 (1) The chief executive officer shall ensure that notice of every rule he or she proposes to make under section 44 is given in the manner and to the persons that the chief executive officer considers appropriate. 2019, c. 6, Sched. 2, s. 19 (1).

Content of notice

(2) The notice must include,

(a) the proposed rule or a summary of the proposed rule;

(b) a concise statement of the purpose of the proposed rule;

(c) an invitation to make written representations with respect to the proposed rule;

(d) the time limit for making written representations;

(e) if a summary is provided, information about how the entire text of the proposed rule may be obtained; and

(f) a description of the anticipated costs and benefits of the proposed rule. 1998, c. 15, Sched. B, s. 45 (2).

Opportunity for comment

(3) On giving notice under subsection (1), the chief executive officer shall give a reasonable opportunity to interested persons to make written representations with respect to the proposed rule within such reasonable period as the chief executive officer considers appropriate. 2019, c. 6, Sched. 2, s. 19 (1).

Exceptions to notice requirement

(4) Notice under subsection (1) is not required if what is proposed is an amendment that does not materially change an existing rule. 1998, c. 15, Sched. B, s. 45 (4).

Notice of changes

(5) If, after considering the submissions, the chief executive officer proposes material changes to the proposed rule, the chief executive officer shall ensure notice of the proposed changes is given in such manner and to such persons as the chief executive officer may determine. 2019, c. 6, Sched. 2, s. 19 (1).

Content of notice

(6) The notice must include,

(a) the proposed rule with the changes incorporated or a summary of the proposed changes;

(b) a concise statement of the purpose of the changes;

(c) an invitation to make written representations with respect to the proposed rule;

(d) the time limit for making written representations;

(e) if a summary is provided, information about how the entire text of the proposed rule may be obtained; and

(f) a description of the anticipated costs and benefits of the proposed rule. 1998, c. 15, Sched. B, s. 45 (6).

Representations re changes

(7) On giving notice of changes, the chief executive officer shall give a reasonable opportunity to interested persons to make written representations with respect to the changes within such reasonable period as the chief executive officer considers appropriate. 2019, c. 6, Sched. 2, s. 19 (1).

Making the rule

(8) If notice under this section is required, the chief executive officer may make the rule only at the end of this process and after considering all representations made as a result of that process. 2019, c. 6, Sched. 2, s. 19 (1).

Public inspection

(9) The chief executive officer must make the proposed rule and the written representations made under this section available for public inspection during normal business hours at the offices of the Board. 1998, c. 15, Sched. B, s. 45 (9); 2019, c. 6, Sched. 2, s. 19 (2).

Consultation

(10) If the chief executive officer proposes to make a rule under clause 44 (1) (a), notice shall not be given under subsection (1) until after the chief executive officer has consulted with

gas transmitters, gas distributors or storage companies, as appropriate. 2019, c. 6, Sched. 2, s. 19 (3).

Amendment

(11) In this section, a rule includes an amendment to a rule and a revocation of a rule. 1998, c. 15, Sched. B, s. 45 (11).

---

v **Section Amendments with date in force (d/m/y)**

Rules, effective date and gazette publication

46 (1) A rule comes into force on the day specified in the rule. 1998, c. 15, Sched. B, s. 46 (1).

Publication

(2) The Board shall publish every rule that comes into force in *The Ontario Gazette* as soon after the rule is made as practicable. 1998, c. 15, Sched. B, s. 46 (2).

Effect of non-publication

(3) A rule that is not published is not effective against a person who has not had actual notice of it. 1998, c. 15, Sched. B, s. 46 (3).

Effect of publication

(4) Publication of a rule in *The Ontario Gazette*,

(a) is, in the absence of evidence to the contrary, proof of its text and of its making; and

(b) shall be deemed to be notice of its contents to every person subject to it or affected by it. 1998, c. 15, Sched. B, s. 46 (4).

Judicial notice

(5) If a rule is published in *The Ontario Gazette*, judicial notice shall be taken of it, of its content and of its publication. 1998, c. 15, Sched. B, s. 46 (5).

PART IV
GAS MARKETING

Definitions, Part IV

47 In this Part,

"gas marketer" means a person who,

(a) sells or offers to sell gas to a low-volume consumer,

(b) acts as the agent or broker for a seller of gas to a low-volume consumer, or

(c) acts or offers to act as the agent or broker of a low-volume consumer in the purchase of gas,

and "gas marketing" has a corresponding meaning; ("agent de commercialisation de gaz", "commercialisation de gaz")

"low-volume consumer" means a person who annually uses less than the amount of gas prescribed by regulation. ("petit consommateur") 1998, c. 15, Sched. B, s. 47.

Requirement to hold licence

48 (1) No person shall carry on business as a gas marketer unless the person holds a gas marketer's licence. 1998, c. 15, Sched. B, s. 48 (1).

Restriction on name use

(2) A gas marketer shall not carry on business in a name other than the name in which it is licensed unless authorized to do so in the licence. 1998, c. 15, Sched. B, s. 48 (2).

Exclusion

(3) This section does not apply to,

(a) a gas distributor acting in accordance with an order of the Board including an order made under section 57.1; or

(b) a gas distributor to whom section 36 does not apply pursuant to an exemption set out in the regulations. 2003, c. 3, s. 36; 2023, c. 9, Sched. 24, s. 2.

Section Amendments with date in force (d/m/y)

Where not in compliance

49 A gas marketing contract between a low-volume consumer and a person who is not in compliance with section 48 may not be enforced against that consumer. 1998, c. 15, Sched. B, s. 49.

Application for licence

50 (1) A person may apply to the Board for the issuance or renewal of a gas marketing licence. 2003, c. 3, s. 37.

Regulations

(2) The Lieutenant Governor in Council may make regulations prescribing requirements for a gas marketing licence which, if not met, will result in the refusal to issue or renew a licence. 2003, c. 3, s. 37.

Section Amendments with date in force (d/m/y)

Licence conditions and renewals

Licence conditions

51 (1) A licence under this Part may contain such conditions as are appropriate having regard to the objectives of the Board. 2010, c. 8, s. 38 (6).

Licence renewals

(2) A licence under this Part shall be renewed at such times as may be prescribed by regulation. 2010, c. 8, s. 38 (6).

Regulations

(3) The Lieutenant Governor in Council may make regulations prescribing the time or times at which a licence is to be renewed for the purposes of subsection (2). 2021, c. 2, Sched. 2, s. 2.

Section Amendments with date in force (d/m/y)

Amendment of licence

52 The Board may, on the application of any person, amend a licence if it considers the amendment to be,

(a) necessary to implement a directive issued under section 27, 27.1 or 28.7; or

(b) in the public interest, having regard to the objectives of the Board. 2003, c. 3, s. 37; 2010, c. 8, s. 38 (7).

Section Amendments with date in force (d/m/y)

Cancellation on request

53 The Board may cancel a licence on the request in writing of the licence holder. 2003, c. 3, s. 38.

Section Amendments with date in force (d/m/y)

54 REPEALED: 2003, c. 3, s. 39.

Section Amendments with date in force (d/m/y)

55 REPEALED: 2003, c. 3, s. 39.

Section Amendments with date in force (d/m/y)

PART V
REGULATION OF ELECTRICITY

Definitions, Part V

56 In this Part,

"alternative energy source" means an energy source that is an alternative energy source for the purposes of the *Electricity Act, 1998*; ("source d'énergie de remplacement")

"ancillary services" means services necessary to maintain the reliability of the IESO-controlled grid, including frequency control, voltage control, reactive power and operating

reserve services; (“services accessoires”)

“consumer” means a person who uses, for the person’s own consumption, electricity that the person did not generate; (“consommateur”)

“Financial Corporation” has the same meaning as in the *Electricity Act, 1998*; (“Société financière”)

“generate”, with respect to electricity, means to produce electricity or provide ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system; (“produire”)

“generation facility” means a facility for generating electricity or providing ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system, and includes any structures, equipment or other things used for that purpose; (“installation de production”)

“generator” means a person who owns or operates a generation facility; (“producteur”)

“IESO-administered markets” means the markets established by the market rules under the *Electricity Act, 1998*; (“marchés administrés par la SIERE”)

“IESO-controlled grid” means the transmission systems with respect to which, pursuant to agreements, the IESO has authority to direct operations; (“réseau dirigé par la SIERE”)

“low-volume consumer” means a consumer who annually uses less than 150,000 kilowatt hours of electricity or such other amount of electricity as is prescribed by the regulations; (“petit consommateur”)

“market participant” means a person who is authorized by the market rules to participate in the IESO-administered markets or to cause or permit electricity to be conveyed into, through or out of the IESO-controlled grid; (“intervenant du marché”)

“market rules” means the rules made under section 32 of the *Electricity Act, 1998*; (“règles du marché”)

"renewable energy source" means an energy source that is a renewable energy source for the purposes of the *Electricity Act, 1998*; ("source d'énergie renouvelable")

"retail", with respect to electricity, means,

(a) to sell or offer to sell electricity to a consumer,

(b) to act as agent or broker for a retailer with respect to the sale or offering for sale of electricity, or

(c) to act or offer to act as an agent or broker for a consumer with respect to the sale or offering for sale of electricity; ("vendre au détail")

"Retail Settlement Code" means the Retail Settlement Code issued by the Board, as amended from time to time; ("code appelé Retail Settlement Code")

"retailer" means a person who retails electricity. ("détaillant") 1998, c. 15, Sched. B, s. 56; 2002, c. 23, s. 4 (6, 7); 2003, c. 3, s. 40; 2004, c. 23, Sched. B, s. 9 (1, 2), (4, 5), (7-9); 2007, c. 8, s. 222; 2009, c. 12, Sched. D, s. 9; 2009, c. 33, Sched. 18, s. 21; 2021, c. 2, Sched. 2, s. 3.

Section Amendments with date in force (d/m/y)

Requirement to hold licence

57 Neither the IESO nor the Smart Metering Entity shall exercise their powers or perform their duties under the *Electricity Act, 1998* unless licensed to do so under this Part and, except as otherwise provided under this Act, no other person shall, unless licensed to do so under this Part,

(a) own or operate a distribution system;

(b) own or operate a transmission system;

(c) generate electricity or provide ancillary services for sale through the IESO-administered markets or directly to another person;

(c.1) engage in unit sub-metering;

(d) retail electricity;

(e) purchase electricity or ancillary services in the IESO-administered markets or directly from a generator;

(f) sell electricity or ancillary services through the IESO-administered markets or directly to another person, other than a consumer;

(g) direct the operation of transmission systems in Ontario;

(h) operate the market established by the market rules; or

(i) engage in an activity prescribed by the regulations that relates to electricity. 1998, c. 15, Sched. B, s. 57; 2002, c. 1, Sched. B, s. 6; 2004, c. 23, Sched. B, s. 10; 2006, c. 3, Sched. C, s. 4; 2010, c. 8, s. 38 (8); 2014, c. 7, Sched. 23, s. 4; 2023, c. 9, Sched. 24, s. 3.

Section Amendments with date in force (d/m/y)

Pilot or demonstration projects to facilitate innovation

Exemption from licence requirement

57.1 (1) The Board may by order exempt a person from the requirement to be licensed under this Part in respect of any activity referred to in clause 57 (a), (c.1), (d), (e) or (f) for a period of no more than five years, in order to permit the person to participate in a pilot or demonstration project,

(a) that meets any criteria prescribed by the regulations; and

(b) that the Board determines is in furtherance of its objective to facilitate innovation in the electricity sector under paragraph 4 of subsection 1 (1). 2023, c. 9, Sched. 24, s. 4.

Same, gas marketing

(2) In making an order under subsection (1), the Board may additionally exempt a person from the requirement to be licensed under Part IV in respect of any activity to which section 48 applies for a period of no more than five years, in order to permit the person to

participate in the pilot or demonstration project that is the subject of the order. 2023, c. 9, Sched. 24, s. 4.

Extension

(3) The Board may by order extend an exemption granted under subsection (1) or (2) for further periods of no more than five years each. 2023, c. 9, Sched. 24, s. 4.

Amendment, revocation

(4) The Board may by order amend or revoke an exemption granted under subsection (1) or (2) or extended under subsection (3). 2023, c. 9, Sched. 24, s. 4.

Hearing not required

(5) The Board may make an order under this section without a hearing. 2023, c. 9, Sched. 24, s. 4.

Application of exemption

(6) An exemption under this section applies only with respect to the exempted person's participation in the pilot or demonstration project and for no other purpose. 2023, c. 9, Sched. 24, s. 4.

---

v **Section Amendments with date in force (d/m/y)**

Where not in compliance

58 A contract between a member of a prescribed class of consumers and a person who is not in compliance with section 57 may not be enforced against that consumer. 2010, c. 8, s. 38 (9).

---

v **Section Amendments with date in force (d/m/y)**

Head office of distributor in Ontario

58.1 (1) A distributor that is licensed under this Part to own or operate a distribution system shall maintain its head office in Ontario. 2015, c. 29, s. 9.

What constitutes "maintained in Ontario"

(2) For the purposes of subsection (1), a distributor maintains its head office in Ontario if,

(a) the principal executive office for the distributor and its subsidiaries is located in Ontario;

(b) the chief executive officer and substantially all of the officers with strategic decision-making or management authority for the distributor and its subsidiaries principally perform their duties at that principal executive office or elsewhere in Ontario and are resident in Ontario; and

(c) substantially all of the strategic decision-making, corporate planning, corporate finance and other executive functions of the distributor and its subsidiaries are carried out at that principal executive office or elsewhere in Ontario. 2015, c. 29, s. 9.

Definition, "subsidiary"

(3) In this section,

"subsidiary", with respect to a corporation, has the same meaning as in the *Business Corporations Act*. 2015, c. 29, s. 9.

Section Amendments with date in force (d/m/y)

Interim licences

Emergency

59 (1) Despite this Act, the Board may issue an interim licence authorizing a person to undertake any of the activities described in section 57 if the Board considers it necessary to do so to ensure the reliable supply of electricity to consumers. 1998, c. 15, Sched. B, s. 59 (1).

Failure to meet obligations or reliability standards

(1.1) Subsection (2) applies if the Board has determined that,

(a) a distributor has failed or is likely to fail to meet its obligations under section 29 of the Electricity Act, 1998; or

(b) a transmitter has failed or is likely to fail to meet,

(i) a reliability standard as defined in subsection 2 (1) of the *Electricity Act, 1998*,

(ii) a reliability standard provided for in an order, licence or code issued by the Board, or in the market rules established under section 32 of the *Electricity Act, 1998*, or

(iii) a standard prescribed by regulation under this Act. 2015, c. 29, s. 10 (1).

Powers of Board

(2) The Board may,

(a) require the licensee, as a condition of an interim licence, to take possession and control of the business of the transmitter or distributor;

(b) order the transmitter or distributor to surrender possession and control of its business to the person licensed under subsection (1); and

(c) without a hearing, amend or suspend the licence of the transmitter or distributor. 2015, c. 29, s. 10 (2).

Conduct under cl. (2) (a)

(3) A person who is required under clause (2) (a) to take possession and control of the business of a transmitter or distributor may, subject to the conditions of the interim licence, carry on, manage and conduct the operations of the business in the name of the transmitter or distributor, including,

(a) preserving, maintaining and adding to the property of the business;

(b) receiving the income and revenue of the business;

(c) issuing cheques from, withdrawing money from and otherwise dealing with the accounts of the business;

(d) retaining or dismissing employees, consultants, counsel and other assistance for the business;

(e) directing the employees of the business; and

(f) conducting, settling and commencing litigation relating to the business. 2003, c. 3, s. 42 (2); 2015, c. 29, s. 10 (3).

Liability

(3.1) A person who is required under clause (2) (a) to take possession and control of the business of a transmitter or distributor is not liable for anything that results from taking possession and control of the business or otherwise exercising or performing the person's powers and duties under this Act, the interim licence or any order of the Board, unless liability arises from the person's negligence or wilful misconduct. 2003, c. 3, s. 42 (2); 2015, c. 29, s. 10 (4).

Disposal of assets

(4) A person described in subsection (3) may dispose of such assets as are ordinarily disposed of in the normal course of carrying on the business of a transmitter or distributor. 1998, c. 15, Sched. B, s. 59 (4); 2015, c. 29, s. 10 (5).

No notice

(5) The Board may act under this section without notice and without a hearing. 1998, c. 15, Sched. B, s. 59 (5).

Review

(6) The Board shall, upon the request of a transmitter or distributor against whom an order is made under clause (2) (b), hold a hearing to review the order. 1998, c. 15, Sched. B, s. 59 (6); 2015, c. 29, s. 10 (6).

Order not stayed

(7) A request for a hearing does not stay the order made under clause (2) (b). 1998, c. 15, Sched. B, s. 59 (7).

Action on review

(8) After the hearing, the Board may confirm or amend its order and may extend the order. 1998, c. 15, Sched. B, s. 59 (8).

Term of licence

(9) An order made or licence issued under this section expires six months after it is made or issued unless the Board orders that it be extended. 1998, c. 15, Sched. B, s. 59 (9); 2015, c. 29, s. 10 (7).

Retain ownership

(10) Despite subsection (2) or (3), and subject to subsection (4) a transmitter or distributor to whom an order is issued under clause (2) (b) retains ownership of any assets of the business that the transmitter or distributor owned before the order was issued, subject to any encumbrances. 1998, c. 15, Sched. B, s. 59 (10); 2015, c. 29, s. 10 (8).

No compensation

(11) A transmitter or distributor to whom an order is issued under clause (2) (b) is not entitled to any compensation from the Crown, the Board or any person for being required to surrender possession and control of its business. 1998, c. 15, Sched. B, s. 59 (11); 2015, c. 29, s. 10 (9).

---

v **Section Amendments with date in force (d/m/y)**

Appointment of supervisor

Failure to meet financial obligations, reliability standards, etc.

59.1 (1) Subsection (2) applies if the Board has determined that a transmitter or distributor,

(a) has failed or is likely to fail to meet its financial obligations as they become due, or that the financial condition of the transmitter or distributor has otherwise significantly deteriorated; or

(b) may not be able to meet,

(i) a reliability standard as defined in subsection 2 (1) of the *Electricity Act, 1998*,

(ii) a reliability standard provided for in an order, licence or code issued by the Board, or in the market rules established under section 32 of the *Electricity Act, 1998*, or

(iii) a standard prescribed by regulation under this Act. 2015, c. 29, s. 11.

Appointment

(2) Where any of the circumstances in subsection (1) apply, the Board may appoint a supervisor to,

(a) supervise the management of the business of the transmitter or distributor; and

(b) prepare such reports and information, including any recommendations, as may be required by the Board, and file them with the Board. 2015, c. 29, s. 11.

Provision of information to supervisor

(3) The transmitter or distributor shall promptly provide the supervisor with such assistance, information and access to documents or records relating to the business of the transmitter or distributor as the supervisor may reasonably request, within the time period and in the form reasonably requested by the supervisor. 2015, c. 29, s. 11.

Board orders

(4) Upon receipt of a report or information from a supervisor under clause (2) (b), the Board may order that the transmitter or distributor take such remedial steps as the Board considers appropriate, having regard to the report or information and any recommendations made by the supervisor. 2015, c. 29, s. 11.

Term and renewal of appointment

(5) An appointment under subsection (2) shall be for a specified term that does not exceed one year and may be renewed once. 2015, c. 29, s. 11.

Costs

(6) The Board may order that the costs incurred by the Board or the supervisor under this section shall be paid by the transmitter or the distributor, or as otherwise determined by the Board. 2015, c. 29, s. 11.

May act without notice

(7) The Board may act under this section without notice and without a hearing. 2015, c. 29, s. 11.

Hearing to review

(8) The Board shall, upon the request of a transmitter or distributor against whom an order has been made under subsection (4), hold a hearing to review the order. 2015, c. 29, s. 11.

Evidence, etc.

(9) Sections 110 to 112 apply, with necessary modifications, to a supervisor appointed under this section, to documents, records and information obtained by a supervisor, and to reports

and information prepared by a supervisor under clause (2) (b). 2015, c. 29, s. 11.

Section Amendments with date in force (d/m/y)

Application for licence

60 (1) A person may apply to the Board for the issuance or renewal of a licence authorizing one or more of the activities referred to in section 57 as specified in the application. 1998, c. 15, Sched. B, s. 60 (1); 2003, c. 3, s. 43 (1).

(2) Repealed: 2003, c. 3, s. 43 (2).

Section Amendments with date in force (d/m/y)

61 Repealed: 2003, c. 3, s. 44.

Section Amendments with date in force (d/m/y)

62 Repealed: 2003, c. 3, s. 44.

Section Amendments with date in force (d/m/y)

63 Repealed: 2003, c. 3, s. 44.

Section Amendments with date in force (d/m/y)

64 Repealed: 2003, c. 3, s. 44.

Section Amendments with date in force (d/m/y)

65 Repealed: 2003, c. 3, s. 44.

Section Amendments with date in force (d/m/y)

Mutual access, electricity generated outside Ontario

66 If an application for a licence relates to electricity generated from facilities located in a jurisdiction outside of Ontario, the Board may, in determining whether or not to issue a licence, have regard to whether that jurisdiction allows for equivalent access to its electricity markets for electricity generated from facilities located in Ontario. 1998, c. 15, Sched. B, s. 66; 2003, c. 3, s. 45.

Section Amendments with date in force (d/m/y)

67 REPEALED: 2003, c. 3, s. 46.

Section Amendments with date in force (d/m/y)

68 REPEALED: 2003, c. 3, s. 46.

Section Amendments with date in force (d/m/y)

69 REPEALED: 2003, c. 3, s. 46.

Section Amendments with date in force (d/m/y)

Licence conditions

70 (1) A licence under this Part may prescribe the conditions under which a person may engage in an activity set out in section 57 and a licence may also contain such other conditions as are appropriate having regard to the objectives of the Board and the purposes of the *Electricity Act, 1998*. 1998, c. 15, Sched. B, s. 70 (1).

Approvals, etc., with or without holding hearing

(1.1) The Board may, with or without a hearing, grant an approval, consent or make a determination that may be required for any of the matters provided for in a licensee's licence. 2009, c. 12, Sched. D, s. 10.

Examples of conditions

(2) The conditions of a licence may include provisions,

(a) specifying the period of time during which the licence will be in effect;

(b) requiring the licensee to provide, in the manner and form determined by the Board, such information as the Board may require;

(c) requiring the licensee to enter into agreements with other persons on specified terms (including terms for a specified duration) approved by the Board relating to its trading or operations or for the connection to or use of any lines or plant owned or operated by the licensee or the other party to the agreement;

(d) governing the conduct of the licensee, including the conduct of,

(i) a transmitter or distributor as that conduct relates to its affiliates,

(ii) a distributor as that conduct relates to a retailer,

(ii.1) a distributor or suite meter provider as such conduct relates to,

(A) the disconnection of the supply of electricity to a consumer, including the manner in which and the time within which the disconnection takes place or is to take place, and with respect to a low-volume consumer, periods during which the disconnection may not take place,

(B) the manner, timing and form in which the notice under subsection 31 (2) of the *Electricity Act, 1998* is to be provided to the consumer, and

(C) subject to the regulations, the manner and circumstances in which security is to be provided or not to be provided by a consumer to a distributor or suite meter provider, including,

(1) the interest rate to be applied to amounts held on deposit and payable by the distributor or suite meter provider to the consumer for the amounts,

(2) the manner and time or times by which the amounts held on deposit may or must be paid or set-off against amounts otherwise due or payable by the consumer,

(3) the circumstances in which security need not be provided or in which specific arrangements in respect of security may or must be provided by the distributor or suite meter provider to the consumer, and

(4) such other matters as the Board may determine in respect of security deposits,

(iii) a retailer, and

(iv) a generator, retailer or person licensed to engage in an activity described in clause 57 (f) or an affiliate of that person as that conduct relates to the abuse or possible abuse of market power;

(d.1) governing conditions relating to any matter prescribed by regulation in respect of retailers of electricity in relation to the retailing of electricity, subject to any regulations made under this Act;

(e) specifying methods or techniques to be applied in determining the licensee's rates;

(f) requiring the licensee to maintain specified accounting records, prepare accounts according to specified principles and maintain organizational units or separate accounts for separate businesses in order to prohibit subsidies between separate businesses;

(g) specifying performance standards, targets and criteria;

(h) specifying connection or retailing obligations to enable reasonable demands for electricity to be met;

(i) specifying information reporting requirements relating to the source of electricity and emissions caused by the generation of electricity;

(j) requiring the licensee to expand or reinforce its transmission or distribution system in accordance with market rules in such a manner as the IESO or the Board may determine;

(k) requiring the licensee to enter into an agreement with the IESO that gives the IESO the authority to direct operations of the licensee's transmission system;

(l) Repealed: 2016, c. 10, Sched. 2, s. 15.

(m) requiring licensees, where a directive has been issued under section 28.2, to implement such steps or such processes as the Board or the directive requires in order

to address risks or liabilities associated with customer billing and payment cycles in respect of the cost of electricity at the retail and at the wholesale levels and risks or liabilities associated with non-payment or default by a consumer or retailer. 1998, c. 15, Sched. B, s. 70 (2); 2003, c. 3, s. 47 (1); 2004, c. 23, Sched. B, s. 11 (1-3); 2010, c. 8, s. 38 (10, 11); 2016, c. 10, Sched. 2, s. 15; 2017, c. 1, s. 2 (1).

Deemed conditions of licences, transmitters and distributors

(2.1) Every licence issued to a transmitter or distributor shall be deemed to contain the following conditions:

1. Repealed: 2021, c. 25, Sched. 19, s. 1.

2. The licensee is required to prepare plans, in the manner and at the times mandated by the Board or as prescribed by regulation and to file them with the Board for approval for,

    i. the expansion or reinforcement of the licensee's transmission system or distribution system to accommodate the connection of renewable energy generation facilities, and

    ii. the development and implementation of the smart grid in relation to the licensee's transmission system or distribution system.

3. The licensee is required, in accordance with a plan referred to in paragraph 2 that has been approved by the Board or in such other manner and at such other times as mandated by the Board or prescribed by regulation,

    i. to expand or reinforce its transmission system or distribution system to accommodate the connection of renewable energy generation facilities, and

    ii. to make investments for the development and implementation of the smart grid in relation to the licensee's transmission system or distribution system.

4. Repealed: 2019, c. 6, Sched. 3, s. 12 (1).

2009, c. 12, Sched. D, s. 10; 2017, c. 16, Sched. 1, s. 44 (1); 2019, c. 6, Sched. 3, s. 12 (1); 2021, c. 25, Sched. 19, s. 1.

(2.2) Repealed: 2020, c. 34, Sched. 14, s. 2.

Deemed condition of licences, unit sub-meter provider, *Ontario Rebate for Electricity Consumers Act, 2016*

(2.3) Every licence issued to a unit sub-meter provider is deemed to contain the condition that the unit sub-meter provider is required to comply with the *Ontario Rebate for Electricity Consumers Act, 2016* and the regulations made under it. 2016, c. 19, s. 17 (2).

(2.4) Repealed: 2019, c. 6, Sched. 3, s. 12 (2).

Where no agreement

(3) If the parties to an agreement under clause (2) (k) cannot agree on a proposed amendment to the agreement, the parties may jointly apply to the Board for a resolution of the matter. 1998, c. 15, Sched. B, s. 70 (3).

Market rules

(4) Every licence shall be deemed to contain a condition that the licensee comply with the market rules that apply to that licensee. 1998, c. 15, Sched. B, s. 70 (4).

Records in Ontario

(4.1) Every licence shall be deemed to contain a condition requiring the licensee to comply with any requirements set by the Board with respect to keeping certain records of the licensee in Ontario. 2015, c. 29, s. 12 (1).

Abuse of market power

(5) Without limiting the generality of subsection (1), a licence to engage in an activity described in clause 57 (c), (d) or (f) may contain conditions to address the abuse or possible abuse of market power, including conditions,

(a) establishing minimum and maximum prices or a range of prices at which electricity may be offered for sale or sold through the IESO-administered markets or directly to another person or class of persons;

(b) restricting the duration of contracts between licensees and any other person; and

(c) restricting significant investment in or acquisition of generation facilities located in Ontario. 1998, c. 15, Sched. B, s. 70 (5); 2004, c. 23, Sched. B, s. 11 (4).

Non-exclusive

(6) Unless it provides otherwise, a licence under this Part shall not hinder or restrict the grant of a licence to another person within the same area and the licensee shall not claim any right of exclusivity. 1998, c. 15, Sched. B, s. 70 (6).

Distributors: connection of generation facilities

(6.1) The licence issued to a distributor shall contain conditions governing the connection of generation facilities to the distribution system, including the maximum cumulative generating capacity from generators to whom the regulations made under clause 88 (1) (g.1) or subsection 88 (2.1) apply that the distributor must allow to be connected to the distribution system. 2002, c. 23, s. 4 (8); 2017, c. 34, Sched. 31, s. 1.

Requirement to provide information

(7) Every licence, other than a licence issued to the IESO, is deemed to contain a condition that the licensee is required to provide such reasonable information to the IESO as the IESO may require, in the manner and form specified by the IESO. 2014, c. 7, Sched. 23, s. 5.

Conflict with *Electricity Act, 1998*

(8) In the event of a conflict between a licence condition referred to in sub-subclause (2) (d) (ii.1) (A) and anything in section 31 of the *Electricity Act, 1998*, the licence condition prevails. 2017, c. 1, s. 2 (2).

Affiliates

(9) The licence of a distributor shall specify whether the distributor will comply with section 29 of the *Electricity Act, 1998*,

(a) directly;

(b) through an affiliate;

(c) through another person with whom the distributor or an affiliate of the distributor has a contract; or

(d) through a combination of methods described in clauses (a), (b) and (c), as specified. 1998, c. 15, Sched. B, s. 70 (9); 2002, c. 1, Sched. B, s. 7.

Exception

(10) Despite clause (9) (a) and any licence, a distributor shall not comply with section 29 of the *Electricity Act, 1998* directly after the date prescribed by regulation. 1998, c. 15, Sched. B, s. 70 (10).

Service area of distributor

(11) The licence of a distributor shall specify the area in which the distributor is authorized to distribute electricity. 1998, c. 15, Sched. B, s. 70 (11).

Non-discriminatory access

(12) If a transmitter or distributor is exempt from the requirement to provide non-discriminatory access to its transmission or distribution system in Ontario by regulation made under the *Electricity Act, 1998*, a licence under this Part shall not include a condition requiring the provision of non-discriminatory access unless the licensee has consented to the condition. 1998, c. 15, Sched. B, s. 70 (12).

Limitation

(13) A licence under this Part shall not require a person to dispose of assets or to undertake a significant corporate reorganization. 1998, c. 15, Sched. B, s. 70 (13).

Exclusion

(14) Despite subsection (13), a licence under this Part may require a distributor to establish an affiliate through which it shall comply with subsection (9). 1998, c. 15, Sched. B, s. 70 (14); 2015, c. 29, s. 12 (2).

Scope

(15) This section applies to the exercise of any power under this Act or the *Electricity Act, 1998* in relation to a licence referred to in section 57. 1998, c. 15, Sched. B, s. 70 (15).

Section Amendments with date in force (d/m/y)

Codes that may be incorporated as licence conditions

70.1 (1) The chief executive officer may issue codes that, with such modifications or exemptions as may be specified by the Board under section 70, may be incorporated by reference as conditions of a licence under that section. 2003, c. 3, s. 48; 2019, c. 6, Sched. 2, s. 20 (1).

(2) Repealed: 2019, c. 6, Sched. 2, s. 20 (2).

Approval, etc., of Board

(3) A code issued under this section may provide that an approval, consent or determination of the Board is required, with or without a hearing, for any of the matters provided for in the code. 2003, c. 3, s. 48.

Incorporation of standards, etc.

(4) A code issued under this section may incorporate by reference, in whole or in part, any standard, procedure or guideline. 2003, c. 3, s. 48.

Scope

(5) A code may be general or particular in its application and may be limited as to time or place or both. 2003, c. 3, s. 48.

Legislation Act, 2006, Part III

(6) Part III (Regulations) of the *Legislation Act, 2006* does not apply to a code issued under this section. 2003, c. 3, s. 48; 2006, c. 21, Sched. F, s. 136 (1).

Transition

(7) The following documents issued by the Board, as they read immediately before this section came into force, shall be deemed to be codes issued under this section and the chief executive officer may change or amend the codes in accordance with this section and sections 70.2 and 70.3:

1. The Affiliate Relationships Code for Electricity Transmitters and Distributors.
2. The Distribution System Code.
3. The Electricity Retailer Code of Conduct.
4. The Retail Settlement Code.
5. The Transmission System Code.
6. Such other documents as are prescribed by the regulations. 2003, c. 3, s. 48; 2019, c. 6, Sched. 2, s. 20 (4).

Section Amendments with date in force (d/m/y)

Proposed codes, notice and content

70.2 (1) The chief executive officer shall ensure that notice of every code he or she proposes to issue under section 70.1 is given in the manner and to the persons that the chief executive officer considers appropriate. 2019, c. 6, Sched. 2, s. 21 (1).

Content of notice

(2) The notice must include,

(a) the proposed code or a summary of the proposed code;

(b) a concise statement of the purpose of the proposed code;

(c) an invitation to make written representations with respect to the proposed code;

(d) the time limit for making written representations;

(e) if a summary is provided, information about how the entire text of the proposed code may be obtained; and

(f) a description of the anticipated costs and benefits of the proposed code. 2003, c. 3, s. 48.

Opportunity for comment

(3) On giving notice under subsection (1), the chief executive officer shall give a reasonable opportunity to interested persons to make written representations with respect to the proposed code within such reasonable period as the chief executive officer considers appropriate. 2019, c. 6, Sched. 2, s. 21 (2).

Exceptions to notice requirement

(4) Notice under subsection (1) is not required if what is proposed is an amendment that does not materially change an existing code. 2003, c. 3, s. 48.

Notice of changes

(5) If, after considering the submissions, the chief executive officer proposes material changes to the proposed code, the chief executive officer shall ensure notice of the proposed changes is given in such manner and to such persons as the chief executive officer may determine. 2019, c. 6, Sched. 2, s. 21 (2).

Content of notice

(6) The notice must include,

(a) the proposed code with the changes incorporated or a summary of the proposed changes;

(b) a concise statement of the purpose of the changes;

(c) an invitation to make written representations with respect to the proposed code;

(d) the time limit for making written representations;

(e) if a summary is provided, information about how the entire text of the proposed code may be obtained; and

(f) a description of the anticipated costs and benefits of the proposed code. 2003, c. 3, s. 48.

Representations re changes

(7) On giving notice of changes, the chief executive officer shall give a reasonable opportunity to interested persons to make written representations with respect to the changes within such reasonable period as the chief executive officer considers appropriate. 2019, c. 6, Sched. 2, s. 21 (2).

Issuing the code

(8) If notice under this section is required, the chief executive officer may issue the code only at the end of this process and after considering all representations made as a result of that process. 2019, c. 6, Sched. 2, s. 21 (2).

Public inspection

(9) The chief executive officer must make the proposed code and the written representations made under this section available for public inspection during normal business hours at the offices of the Board. 2003, c. 3, s. 48; 2019, c. 6, Sched. 2, s. 21 (3).

Amendment of code

(10) In this section, a code includes an amendment to a code and a revocation of a code. 2003, c. 3, s. 48.

---

v **Section Amendments with date in force (d/m/y)**

Effective date and gazette publication

70.3 (1) A code issued under section 70.1 comes into force on the day specified in the code. 2003, c. 3, s. 48.

Publication

(2) The Board shall publish every code that comes into force in *The Ontario Gazette* as soon after the code is issued as practicable. 2003, c. 3, s. 48.

Effect of non-publication

(3) A code that is not published is not effective against a person who has not had actual notice of it. 2003, c. 3, s. 48.

Effect of publication

(4) Publication of a code in *The Ontario Gazette*,

(a) is, in the absence of evidence to the contrary, proof of its text and of its issuance; and

(b) shall be deemed to be notice of its contents to every person subject to it or affected by it. 2003, c. 3, s. 48.

Judicial notice

(5) If a code is published in *The Ontario Gazette*, judicial notice shall be taken of it, of its content and of its publication. 2003, c. 3, s. 48.

Section Amendments with date in force (d/m/y)

Regulations, deemed amendments to certain codes

70.4 (1) The Lieutenant Governor in Council may make regulations specifying amendments to the Distribution System Code and the Transmission System Code for the purposes of this section with respect to any of the following matters:

1. Obligations between distributors or transmitters and their customers in respect of cost allocation and cost recovery relating to the construction, expansion or reinforcement of distribution systems or transmission systems, or of connections to those systems.

2. Provisions that must be included in an agreement that is entered into by a distributor or transmitter and a customer that pertains to cost allocation and cost recovery relating to the connection of a customer to the distributor's distribution system or the transmitter's transmission system, as the case may be.

3. Any matter ancillary or consequential to a matter referred to in paragraph 1 or 2. 2024, c. 26, Sched. 2, s. 2.

Same

(2) A regulation made under subsection (1) may be general or particular in respect of its application. 2024, c. 26, Sched. 2, s. 2.

Same

(3) Nothing in subsection (1) or (2) gives the Lieutenant Governor in Council authority to specify an amendment in respect of the Distribution System Code or the Transmission System Code that the chief executive officer is not authorized to include in a code issued under section 70.1. 2024, c. 26, Sched. 2, s. 2.

Deemed amendments

(4) The amendments that a regulation made under subsection (1) specifies in respect of the Distribution System Code or the Transmission System Code are deemed to have been issued under section 70.1 in accordance with section 70.2. 2024, c. 26, Sched. 2, s. 2.

Publication, etc.

(5) Despite subsection (4), section 70.3 does not apply with respect to amendments specified by a regulation made under subsection (1). 2024, c. 26, Sched. 2, s. 2.

Updating

(6) The chief executive officer shall take steps to ensure that amendments specified by a regulation made under subsection (1) are promptly consolidated into the applicable Code. 2024, c. 26, Sched. 2, s. 2.

Restriction on Board modifications

(7) Despite subsection (4) and sections 70 and 70.1, the Board may not specify modifications to or exemptions from an amendment specified by a regulation made under subsection (1). 2024, c. 26, Sched. 2, s. 2.

Restriction on amending, etc.

(8) Despite subsection (4) and section 70.1, the chief executive officer may not issue a code that would amend, revoke or conflict with an amendment specified by a regulation made under subsection (1). 2024, c. 26, Sched. 2, s. 2.

Effect of revocation

(9) Subsections (7) and (8) cease to apply with respect to an amendment specified by a regulation made under subsection (1) if the regulation is revoked. 2024, c. 26, Sched. 2, s. 2.

Not a regulation

(10) For greater certainty, nothing in this section affects the application of subsection 70.1 (6). 2024, c. 26, Sched. 2, s. 2.

Section Amendments with date in force (d/m/y)

Regulations, exemptions from certain codes

70.5 (1) The Lieutenant Governor in Council may make regulations,

(a) exempting any person or thing, or any class of person or thing, from the application of any provision of the Distribution System Code or the Transmission System Code that,

(i) pertains to cost allocation or cost recovery, or

(ii) is ancillary or consequential to a provision of the Code that pertains to cost allocation or cost recovery;

(b) providing for conditions or restrictions of an exemption under clause (a);

(c) in respect of a person or thing that is the subject of an exemption under clause (a), establishing and governing the cost allocation or cost recovery that applies with respect to the person or thing instead of the provision that has been exempted from. 2024, c. 26, Sched. 2, s. 2.

Same

(2) A regulation made under subsection (1) may be general or particular in respect of its application. 2024, c. 26, Sched. 2, s. 2.

Conflict

(3) In the event of a conflict between a regulation made under subsection (1) and any other regulation made under this Act, an order of the Board or a code issued under section 70.1, the regulation made under subsection (1) prevails to the extent of the conflict. 2024, c. 26, Sched. 2, s. 2.

Section Amendments with date in force (d/m/y)

Restriction on business activity

71 (1) Except as provided by this section or the regulations, and subject to subsection 70 (9), a transmitter or distributor shall not, except through one or more affiliates, carry on any business activity other than transmitting or distributing electricity. 2004, c. 23, Sched. B, s. 12; 2021, c. 2, Sched. 2, s. 4 (1).

Exception

(2) Subject to section 80 and such rules as may be prescribed by the regulations, a transmitter or distributor may provide services in accordance with section 29.1 of the *Electricity Act, 1998* that would assist the Government of Ontario in achieving its goals in electricity conservation, including services related to,

(a) the promotion of electricity conservation and the efficient use of electricity;

(b) electricity load management; or

(c) the promotion of cleaner energy sources, including alternative energy sources and renewable energy sources. 2004, c. 23, Sched. B, s. 12.

Exception

(3) A distributor may own and operate,

(a) a renewable energy generation facility that does not exceed 10 megawatts or such other capacity as may be prescribed by regulation and that meets any criteria that may be prescribed by the regulations;

(b) a generation facility that uses technology that produces power and thermal energy from a single source and that meets any criteria that may be prescribed by the regulations; or

(c) a facility that is an energy storage facility and that meets any criteria that may be prescribed by the regulations. 2009, c. 12, Sched. D, s. 11; 2011, c. 1, Sched. 4, s. 1; 2021, c. 2, Sched. 2, s. 4 (2).

Exception in special circumstances

(4) The Board may, if in its opinion special circumstances of a particular case so require, authorize a transmitter or distributor to carry on a business activity other than transmitting or distributing electricity other than through one or more affiliates, in accordance with an order of the Board. 2015, c. 29, s. 13; 2021, c. 2, Sched. 2, s. 4 (3).

Section Amendments with date in force (d/m/y)

Separate accounts

72 Every distributor shall keep its financial records associated with distributing electricity separate from its financial records associated with other activities. 1998, c. 15, Sched. B, s. 72.

73 Repealed: 2015, c. 29, s. 14

Section Amendments with date in force (d/m/y)

Amendment of licence

74 (1) The Board may, on the application of any person, amend a licence if it considers the amendment to be,

(a) necessary to implement a directive issued under this Act; or

(b) in the public interest, having regard to the objectives of the Board and the purposes of the *Electricity Act, 1998*. 2004, c. 23, Sched. B, s. 13.

Further power to amend

(2) In addition to its power to amend a licence under subsection (1), the Board may amend a licence under section 38 of the *Electricity Act, 1998*. 2004, c. 23, Sched. B, s. 13.

Section Amendments with date in force (d/m/y)

75 Repealed: 2003, c. 3, s. 49.

Section Amendments with date in force (d/m/y)

76 Repealed: 2003, c. 3, s. 50.

Section Amendments with date in force (d/m/y)

Suspension or revocation, Board consideration

77 (1)-(4) Repealed: 2003, c. 3, s. 51 (1).

Cancellation of licence

(5) The Board may cancel a licence upon the request in writing of the licence holder. 1998, c. 15, Sched. B, s. 77 (5); 2003, c. 3, s. 51 (2).

(6) Repealed: 2000, c. 26, Sched. D, s. 2 (6).

Section Amendments with date in force (d/m/y)

Orders by Board, electricity rates

Order re: transmission of electricity

78 (1) No transmitter shall charge for the transmission of electricity except in accordance with an order of the Board, which is not bound by the terms of any contract. 2000, c. 26, Sched. D, s. 2 (7).

Order re: distribution of electricity

(2) No distributor shall charge for the distribution of electricity or for meeting its obligations under section 29 of the *Electricity Act, 1998* except in accordance with an order of the Board, which is not bound by the terms of any contract. 2000, c. 26, Sched. D, s. 2 (7).

Order re the Smart Metering Entity

(2.1) The Smart Metering Entity shall not charge for meeting its obligations under Part IV.2 of the *Electricity Act, 1998* except in accordance with an order of the Board, which is not bound by the terms of any contract. 2006, c. 3, Sched. C, s. 5 (1).

(2.3) Repealed: 2019, c. 4, Sched. 4, s. 1 (1).

Rates

(3) The Board may make orders approving or fixing just and reasonable rates for the transmitting or distributing of electricity, unit smart metering or such other activity as may be prescribed and for the retailing of electricity in order to meet a distributor's obligations under section 29 of the *Electricity Act, 1998*. 2009, c. 12, Sched. D, s. 12 (1); 2010, c. 8, s. 38 (14); 2019, c. 4, Sched. 4, s. 1 (2).

Rates

(3.0.1) The Board may make orders approving or fixing just and reasonable rates for the Smart Metering Entity in order for it to meet its obligations under this Act or under Part IV.2 of the *Electricity Act, 1998*. 2006, c. 3, Sched. C, s. 5 (1).

Orders re deferral or variance accounts

(3.0.2) The Board may make orders permitting the Smart Metering Entity or distributors to establish one or more deferral or variance accounts related to costs associated with the

smart metering initiative, in the circumstances prescribed in the regulations. 2006, c. 3, Sched. C, s. 5 (1).

Orders re recovery of smart metering initiative costs

(3.0.3) The Board may make orders relating to the ability of the Smart Metering Entity, distributors, retailers and other persons to recover costs associated with the smart metering initiative, in the situations or circumstances prescribed by regulation and the orders may require them to meet such conditions or requirements as may be prescribed, including providing for the time over which costs may be recovered. 2006, c. 3, Sched. C, s. 5 (1).

Orders re deferral or variance accounts, s. 27.2

(3.0.4) The Board may make orders permitting the IESO, distributors or other licensees to establish one or more deferral or variance accounts related to costs associated with complying with a directive issued under section 27.2. 2009, c. 12, Sched. D, s. 12 (2); 2014, c. 7, Sched. 23, s. 6 (1).

Methods re incentives or recovery of costs

(3.0.5) The Board may, in approving or fixing just and reasonable rates or in exercising the power set out in clause 70 (2) (e), adopt methods that provide,

(a) incentives to a transmitter or a distributor in relation to the siting, design and construction of an expansion, reinforcement or other upgrade to the transmitter's transmission system or the distributor's distribution system; or

(b) for the recovery of costs incurred or to be incurred by a transmitter or distributor in relation to the activities referred to in clause (a). 2009, c. 12, Sched. D, s. 12 (2).

Annual rate plan and separate rates for situations prescribed by regulation

(3.1) The Board shall, in accordance with rules prescribed by the regulations, approve or fix separate rates for the retailing of electricity,

(a) to such different classes of consumers as may be prescribed by the regulations; and

(b) for such different situations as may be prescribed by the regulations. 2004, c. 23, Sched. B, s. 14 (1).

Same

(3.2) The first rates approved or fixed by the Board under subsection (3.1) shall remain in effect for not less than 12 months and the Board shall approve or fix separate rates under subsection (3.1) after that time for periods of not more than 12 months each or for such shorter time periods as the Minister may direct. 2004, c. 23, Sched. B, s. 14 (1).

Rates to reflect cost of electricity

(3.3) In approving or fixing rates under subsection (3.1),

(a) the Board shall forecast the cost of electricity to be consumed by the consumers to whom the rates apply, taking into consideration the adjustments required under section 25.33 of the *Electricity Act, 1998* and shall ensure that the rates reflect these costs; and

(b) the Board shall take into account balances in the IESO's variance accounts established under section 25.33 of the *Electricity Act, 1998* and shall make adjustments with a view to eliminating those balances within 12 months or such shorter time periods as the Minister may direct. 2004, c. 23, Sched. B, s. 14 (1); 2014, c. 7, Sched. 23, s. 6 (2).

Forecasting cost of electricity

(3.4) In forecasting the cost of electricity for the purposes of subsection (3.3), the Board shall have regard to such matters as may be prescribed by the regulations. 2004, c. 23, Sched. B, s. 14 (1).

Imposition of conditions on consumer who enters into retail contract

(3.5) A consumer who enters into or renews a retail contract for electricity after the day he or she becomes subject to a rate approved or fixed under subsection (3.1) is subject to such conditions as may be determined by the Board. 2004, c. 23, Sched. B, 14 (1).

Rates

(4) The Board may make an order under subsection (3) with respect to the retailing of electricity in order to meet a distributor's obligations under section 29 of the *Electricity Act, 1998* even if the distributor is meeting its obligations through an affiliate or through another person with whom the distributor or an affiliate of the distributor has a contract. 1998, c. 15, Sched. B, s. 78 (4).

Same, certain payments of transmitters and distributors

(5) In approving or fixing just and reasonable rates for the transmission or distribution of electricity, the Board shall not include any of the following amounts:

1. Any penalties or fines a transmitter or distributor is required to pay under an Act, except as otherwise provided by the regulations.

2. Any other amounts or classes of amounts a transmitter or distributor is required to pay that are prescribed by the regulations made by the Minister under subsection 88 (2.3). 2023, c. 9, Sched. 24, s. 5.

(5.0.0.1) Repealed: 2023, c. 9, Sched. 24, s. 5.

Same, obligations under s. 29 of *Electricity Act, 1998*

(5.0.1) In approving or fixing just and reasonable rates for the retailing of electricity in order to meet a distributor's obligations under section 29 of the *Electricity Act, 1998*, the Board shall comply with the regulations made under clause 88 (1) (g.5). 2003, c. 8, s. 1.

Same, Hydro One executive compensation

(5.0.2) In approving or fixing just and reasonable rates for Hydro One Limited or any of its subsidiaries, the Board shall not include any amount in respect of compensation paid to the Chief Executive Officer and executives, within the meaning of the *Hydro One Accountability Act, 2018*, of Hydro One Limited. 2018, c. 10, Sched. 1, s. 10.

Same, Hydro One Inc. and subsidiaries

(5.1) In approving or fixing just and reasonable rates for Hydro One Inc. or a subsidiary of Hydro One Inc., the Board shall apply a method or technique prescribed by regulation for the calculation and treatment of transfers made by Hydro One Inc. or its subsidiary, as the case may be, that are authorized by section 50.1 of the *Electricity Act, 1998*. 2002, c. 1, Sched. B, s. 8; 2003, c. 3, s. 52 (2).

Same, statutory right to use corridor land

(5.2) In approving or fixing just and reasonable rates for a transmitter who has a statutory right to use corridor land (as defined in section 114.1 of the *Electricity Act, 1998*), the Board shall apply a method or technique prescribed by regulation for the treatment of the statutory right. 2002, c. 1, Sched. B, s. 8; 2003, c. 3, s. 52 (3).

Same, amounts payable to transmitters under procurement contracts

(5.3) In approving or fixing just and reasonable rates for the transmitting of electricity for a transmitter who is a party to a procurement contract entered into under clause 25.32 (2) (d) of the *Electricity Act, 1998*, the Board shall apply a method that provides for the recovery of amounts paid or to be paid to the transmitter under the procurement contract. 2019, c. 6, Sched. 1, s. 6.

Same, transmission procurement contract costs

(5.4) In approving or fixing just and reasonable rates for the transmitting of electricity for a period, the Board shall include the amounts referred to in subsection (5.3) that apply with respect to that period. 2019, c. 6, Sched. 1, s. 6.

Information

(5.5) The IESO shall, for the purposes of subsections (5.3) and (5.4), provide to the Board such information respecting amounts paid or to be paid to transmitters who are a party to a procurement contract entered into under clause 25.32 (2) (d) of the *Electricity Act, 1998* as the Board may require. 2019, c. 6, Sched. 1, s. 6.

Conditions, etc.

(6) An order under this section may include conditions, classifications or practices, including rules respecting the calculation of rates, applicable,

(a) to the Smart Metering Entity in respect of meeting its obligations;

(b) to an activity prescribed for the purposes of subsection (3); and

(c) to the transmission, distribution or retailing of electricity or unit smart metering. 2009, c. 12, Sched. D, s. 12 (3); 2010, c. 8, s. 38 (16); 2019, c. 4, Sched. 4, s. 1 (4).

Deferral or variance accounts

(6.1) If a distributor has a deferral or variance account that relates to the commodity of electricity, the Board shall, from time to time, or as prescribed by the regulations, make an order under this section that determines whether and how amounts recorded in the account shall be reflected in rates. 2017, c. 2, Sched. 10, s. 2 (4).

Same

(6.2) If a distributor has a deferral or variance account that does not relate to the commodity of electricity, the Board shall, from time to time, or as prescribed by the regulations, make an order under this section that determines whether and how amounts recorded in the account shall be reflected in rates. 2017, c. 2, Sched. 10, s. 2 (4).

Same

(6.3) An order that determines whether and how amounts recorded in a deferral or variance account shall be reflected in rates shall be made in accordance with the regulations. 2003, c. 3, s. 52 (4).

Same

(6.4) If an order that determines whether and how amounts recorded in a deferral or variance account shall be reflected in rates is made after the time required by subsection (6.1) or (6.2) and the delay is due in whole or in part to the conduct of a distributor, the Board may reduce the amount that is reflected in rates. 2003, c. 3, s. 52 (4).

Same

(6.5) If an amount recorded in a deferral or variance account of a distributor is reflected in rates, the Board shall consider the appropriate number of billing periods over which the amount shall be divided in order to mitigate the impact on consumers. 2003, c. 3, s. 52 (4).

(6.6) Repealed: 2021, c. 2, Sched. 2, s. 5 (2).

Fixing other rates

(7) Upon an application for an order approving or fixing rates, the Board may, if it is not satisfied that the rates applied for are just and reasonable, fix such other rates as it finds to be just and reasonable. 1998, c. 15, Sched. B, s. 78 (7).

Burden of proof

(8) Subject to subsection (9), in an application made under this section, the burden of proof is on the applicant. 1998, c. 15, Sched. B, s. 78 (8).

Order

(9) If the Board of its own motion, or upon the request of the Minister, commences a proceeding to determine whether any of the rates that the Board may approve or fix under this section are just and reasonable, the Board shall make an order under subsection (3) and

the burden of establishing that the rates are just and reasonable is on the transmitter or distributor, as the case may be. 2010, c. 8, s. 38 (17); 2019, c. 4, Sched. 4, s. 1 (5).

Note: On the day subsection 38 (15) of the *Energy Consumer Protection Act, 2010* comes into force, subsection 78 (9) of the Act is amended by striking out "the transmitter or distributor" and substituting "the transmitter, distributor or unit smart meter provider". (See: 2019, c. 4, Sched. 4, s. 1 (6))

Section Amendments with date in force (d/m/y)

Payments to prescribed generator

78.1 (1) The IESO shall make payments to a generator prescribed by the regulations with respect to output that is generated by a unit at a generation facility prescribed by the regulations. 2014, c. 7, Sched. 23, s. 7.

Payment amount

(2) Each payment referred to in subsection (1) shall be the amount determined in accordance with the order of the Board then in effect. 2014, c. 7, Sched. 23, s. 7.

Same, limitation re Ontario Power Generation Inc.

(3) The determination of a payment to Ontario Power Generation Inc. under this section shall not include any consideration of amounts related to activities of Ontario Power Generation Inc. carried out in relation to the *Ontario Fair Hydro Plan Act, 2017*. 2017, c. 16, Sched. 1, s. 44 (3).

Same

(3.1) The amounts referred to in subsection (3) include, without limitation, the following:

1. Amounts related to the appointment of Ontario Power Generation Inc. as the Financial Services Manager under the *Ontario Fair Hydro Plan Act, 2017*.

2. Amounts related to the charging of fees for performing duties as the Financial Services Manager.

3. Amounts related to exercising the powers and performing the duties of the Financial Services Manager.

4. Amounts related to the consolidation of the assets and liabilities for accounting purposes of the Fair Hydro Trust within the meaning of the *Ontario Fair Hydro Plan Act, 2017*. 2017, c. 16, Sched. 1, s. 44 (3); 2019, c. 6, Sched. 3, s. 12 (3).

Same

(3.2) A payment to Ontario Power Generation Inc. under this section shall not include any amounts that may be specified by the regulations relating to its activities under Part II.1 of the *Electricity Act, 1998*. 2022, c. 23, Sched. 1, s. 5.

Board orders

(4) The Board shall make an order under this section in accordance with the rules prescribed by the regulations and may include in the order conditions, classifications or practices, including rules respecting the calculation of the amount of the payment. 2004, c. 23, Sched. B, s. 15.

Fixing other prices

(5) The Board may fix such other payment amounts as it finds to be just and reasonable,

(a) on an application for an order under this section, if the Board is not satisfied that the amount applied for is just and reasonable; or

(b) at any other time, if the Board is not satisfied that the current payment amount is just and reasonable. 2004, c. 23, Sched. B, s. 15.

Burden of proof

(6) Subject to subsection (7), the burden of proof is on the applicant in an application made under this section. 2004, c. 23, Sched. B, s. 15.

Order

(7) If the Board on its own motion or at the request of the Minister commences a proceeding to determine whether an amount that the Board may approve or fix under this section is just and reasonable,

(a) the burden of establishing that the amount is just and reasonable is on the generator; and

(b) the Board shall make an order approving or fixing an amount that is just and reasonable. 2004, c. 23, Sched. B, s. 15.

Application

(8) Subsections (4), (5) and (7) apply only on and after the day prescribed by the regulations for the purposes of subsection (2). 2004, c. 23, Sched. B, s. 15.

---

v **Section Amendments with date in force (d/m/y)**

Payments to the Financial Corporation

78.2 (1) The IESO shall make payments to the Financial Corporation with respect to the Financial Corporation's contracts with generators relating to output generated at generation facilities prescribed by the regulations and the provision of ancillary services at those generation facilities. 2004, c. 23, Sched. B, s. 16.

Payment amounts

(2) The payments to the Financial Corporation in respect of a contract referred to in subsection (1) shall equal the amounts required to reimburse the Financial Corporation for its indirect costs, as determined under the regulations, and its direct costs under the contract. 2004, c. 23, Sched. B, s. 16.

(3) Repealed: 2014, c. 7, Sched. 23, s. 8.

---

v **Section Amendments with date in force (d/m/y)**

78.3 Repealed: 2014, c. 7, Sched. 23, s. 9.

---

v **Section Amendments with date in force (d/m/y)**

78.4 Repealed: 2014, c. 7, Sched. 23, s. 9.

---

v **Section Amendments with date in force (d/m/y)**

Payments to distributors under conservation and demand management programs

78.5 (1) The IESO shall make payments to a distributor with respect to amounts approved by the Board for conservation and demand management programs approved by the Board pursuant to a directive issued under section 27.2. 2014, c. 7, Sched. 23, s. 10 (1).

Amount and timing of payment

(2) The amount and timing of each payment referred to in subsection (1) shall be determined by the Board in accordance with such rules, methods and criteria as may be prescribed by the regulations or mandated by a code issued by the Board or an order of the Board. 2009, c. 12, Sched. D, s. 13.

Regulations review

(3) A regulation made under subsection (2) may require the Board to undertake its review of the amounts referred to in this section at the time or times prescribed by the regulation. 2009, c. 12, Sched. D, s. 13.

(4) Repealed: 2014, c. 7, Sched. 23, s. 10 (2).

---

v **Section Amendments with date in force (d/m/y)**

Conflict with market rules

78.6 In the event of a conflict, sections 78.1, 78.2 and 78.5 prevail over the market rules to the extent of the conflict. 2009, c. 12, Sched. D, s. 13; 2014, c. 7, Sched. 23, s. 11.

---

v **Section Amendments with date in force (d/m/y)**

Rural or remote consumers

79 (1) The Board, in approving just and reasonable rates for a distributor who delivers electricity to rural or remote consumers, shall provide rate protection for those consumers or prescribed classes of those consumers by reducing the rates that would otherwise apply in accordance with the prescribed rules. 1998, c. 15, Sched. B, s. 79 (1).

Special case

(2) In setting rates under subsection (1), the Board shall ensure that the class of rural or remote consumers receiving assistance under section 108 of the *Power Corporation Act* on the day before this section comes into force shall receive rate protection while they continue to,

(a) occupy the same rural residential premises, as defined in section 108 of the *Power Corporation Act*, as they were occupying on that day; and

(b) live in a part of Ontario designated by regulation as a rural or remote area. 1998, c. 15, Sched. B, s. 79 (2).

Compensation

(3) A distributor is entitled to be compensated for lost revenue resulting from the rate reduction provided under subsection (1). 1998, c. 15, Sched. B, s. 79 (3).

Liability

(4) All consumers are required, in accordance with the regulations, to contribute towards the amount of any compensation required under subsection (3) that is not otherwise provided under subsection (4.1). 2017, c. 16, Sched. 2, s. 1 (1).

Payments for certain classes

(4.1) Compensation required under subsection (3) may be provided with respect to one or more prescribed classes of consumers who receive rate protection under this section, in a manner provided for in the regulations. 2017, c. 16, Sched. 2, s. 1 (1).

Money appropriated by the Legislature

(4.2) The compensation provided for in subsection (4.1) shall be paid for out of the money appropriated for those purposes by the Legislature. 2017, c. 16, Sched. 2, s. 1 (1).

Information, etc.

(4.3) If provided for in the regulations, the Board, the IESO and distributors, or any of them, shall provide such information and reports to the Ministry of Energy and to one another as are necessary to facilitate the implementation, administration, funding and delivery of the rate protection or of anything else provided for in this section. 2017, c. 16, Sched. 2, s. 1 (1).

Limitation

(4.4) The compensation to be provided to a distributor and the rate protection to be provided to a consumer under this section are subject to the limitation period provided for in the regulations, if any. 2021, c. 34, Sched. 9, s. 11 (1).

Regulations

(5) The Lieutenant Governor in Council may make regulations,

(a) prescribing the consumers or classes of consumers eligible for rate protection under this section in addition to those described under subsection (2);

(b) designating areas in Ontario as rural or remote areas;

(c) prescribing rules for the calculation of the amount of the rate reduction;

(d) prescribing maximum amounts of the total annual value of rate protection that may be provided under this section;

(e) prescribing rules respecting the amounts that must be collected to compensate distributors, taking into account any compensation provided under subsection (4.1), including rules,

(i) respecting the calculation of those amounts,

(ii) respecting the calculation of any off-set to the liability of consumers under subsection (3) having regard to those amounts,

(iii) establishing the time and manner of collection,

(iv) requiring the amounts to be paid in instalments and requiring the payment of interest or penalties on late payments,

(v) prescribing methods of ensuring that the amounts required cannot be bypassed, and

(vi) respecting the distribution of those amounts to consumers;

(e.1) prescribing classes of consumers for the purposes of subsection (4.1), and governing how and when the compensation is to be provided with respect to the rate protection provided to them, including, without restricting the generality of the foregoing, requiring the IESO to receive payments or amounts from the Minister of Energy and to make payments to licensed distributors or to prescribed persons and prescribing how and when payments are to be made;

(f) respecting the use of money collected in excess of the amount required to compensate distributors;

(g) prescribing the powers and duties of the Board in relation to the calculation of amounts to be collected and the time and manner of collection and distribution;

(g.1) providing for and governing the limitation period for the purposes of subsection (4.4);

(h) respecting any other matter that the Lieutenant Governor in Council considers necessary in relation to the rate protection. 1998, c. 15, Sched. B, s. 79 (5); 2017, c. 16, Sched. 2, s. 1 (2); 2021, c. 34, Sched. 9, s. 11 (2).

General or particular

(6) A regulation under this section may be general or particular in application and may prescribe different rules for different persons or classes of persons. 1998, c. 15, Sched. B, s. 79 (6).

Section Amendments with date in force (d/m/y)

Cost recovery, connecting generation facilities

79.1 (1) The Board, in approving just and reasonable rates for a distributor that incurs costs to make an eligible investment for the purpose of connecting or enabling the connection of a qualifying generation facility to its distribution system, may provide rate protection for prescribed consumers or classes of consumers in the distributor's service area by reducing the rates that would otherwise apply in accordance with the prescribed rules. 2009, c. 12, Sched. D, s. 14; 2017, c. 2, Sched. 10, s. 2 (5).

Distributor entitled to compensation re lost revenue

(2) A distributor is entitled to be compensated for lost revenue resulting from the rate reduction provided under subsection (1) that is associated with costs that have been approved by the Board and incurred by the distributor to make an eligible investment referred to in subsection (1). 2009, c. 12, Sched. D, s. 14.

Consumers' contributions

(3) All consumers are required to contribute towards the amount of any compensation required under subsection (2) in accordance with the regulations. 2009, c. 12, Sched. D, s. 14.

Limitation

(3.1) The rate protection through rate reduction to be provided in respect of a consumer and the compensation to be provided to a distributor under this section are subject to the limitation period provided for in the regulations, if any. 2021, c. 34, Sched. 9, s. 11 (3).

Regulations

(4) The Lieutenant Governor in Council may make regulations,

(a) prescribing consumers or classes of consumers eligible for rate protection under this section;

(b) prescribing criteria to be met by a qualifying generation facility;

(c) prescribing the criteria to be satisfied for an investment to be an eligible investment;

(d) prescribing rules for the calculation of the amount of the rate reduction;

(e) prescribing maximum amounts of the total annual value of rate protection that may be provided under this section;

(f) prescribing rules respecting the amounts that must be collected to compensate distributors, including rules,

(i) respecting the calculation of those amounts,

(ii) establishing the time and manner of collection,

(iii) requiring the amounts to be paid in instalments and requiring the payment of interest or penalties on late payments,

(iv) prescribing methods of ensuring that the amounts required cannot be bypassed, and

(v) respecting the distribution of the amounts collected;

(g) prescribing the powers and duties of the Board in relation to the calculation of amounts to be collected and the time and manner of collection and distribution;

(g.1) providing for and governing the limitation period for the purposes of subsection (3.1);

(h) respecting any other matter that the Lieutenant Governor in Council considers necessary for the purposes of this section. 2009, c. 12, Sched. D, s. 14; 2021, c. 34, Sched. 9, s. 11 (4).

Definitions

(5) In this section,

"eligible investment" means an investment in the construction, expansion or reinforcement of a distribution line, transformer, plant or equipment used for conveying electricity at voltages of 50 kilovolts or less that meets the criteria prescribed by regulation; ("investissement admissible")

"qualifying generation facility" means a generation facility that meets the criteria prescribed by regulation. ("installation de production admissible") 2009, c. 12, Sched. D, s. 14.

Section Amendments with date in force (d/m/y)

Rate assistance

79.2 (1) The Minister shall make provision for rate assistance for rate-assisted consumers having regard to their economic circumstances, and where the Minister makes such

provision, shall do so out of the money provided for in subsection (4). 2017, c. 16, Sched. 2, s. 2.

OESP

(2) The program known as the "Ontario Electricity Support Program" in English and "Programme ontarien d'aide relative aux frais d'électricité" in French is continued for the purpose of providing rate assistance to rate-assisted consumers having regard to their economic circumstances. 2017, c. 16, Sched. 2, s. 2.

Administered by Board

(3) The Ontario Electricity Support Program shall be administered by the Board, or when the regulations so provide, by a Minister of the Crown or other entity provided for in the regulations. 2017, c. 16, Sched. 2, s. 2.

Money appropriated by the Legislature

(4) The money required for the purposes of the Ontario Electricity Support Program shall be paid out of the money appropriated for those purposes by the Legislature, once the amounts recorded in the variance account referred to in subsection (5) are no longer sufficient to provide for the funding of the program when taken on their own. 2017, c. 16, Sched. 2, s. 2.

Variance account

(5) The money required for the purposes of the Ontario Electricity Support Program shall be provided out of the credit balance in the variance account maintained by the IESO under the Program as it existed before the coming into force of section 2 of Schedule 2 to the *Fair Hydro Act, 2017* until the amounts recorded in the account are no longer sufficient, when taken on their own, to fund the Program. 2017, c. 16, Sched. 2, s. 2.

Variance account depleted

(6) The IESO shall provide the Ministry of Energy with advance notice, on a timely basis, of the time the IESO estimates that the amounts reflected in the variance account would be less than the amount required to meet its obligations related to funding the Ontario Electricity Support Program for the upcoming month. 2017, c. 16, Sched. 2, s. 2.

How provided

(7) Rate assistance provided under this section shall be provided with respect to consumers prescribed in the regulations, and shall be provided at the times provided for in the

regulations and in the amounts and in the manner provided for in the regulations. 2017, c. 16, Sched. 2, s. 2.

Payments with respect to prior use

(8) The regulations may require provision of rate assistance to prescribed classes of rate-assisted consumers with respect to electricity consumed during a period prior to the date of the making of the regulation, but no such rate assistance shall be required under the regulations with respect to electricity consumed before January 1, 2016. 2017, c. 16, Sched. 2, s. 2.

Transitional

(9) The regulations may require the provision of rate assistance for a rate-assisted consumer with respect to a period prior to the date on which the consumer became a rate-assisted consumer if the consumer meets all of the criteria prescribed by the regulations. 2017, c. 16, Sched. 2, s. 2.

Distributors, etc.

(10) A distributor, a unit sub-meter provider and any other person or entity that may be prescribed is entitled to be compensated from the money referred to in subsection (4) or (5), as the case may be, for any lost revenue resulting from the provision of rate assistance under the Ontario Electricity Support Program. 2017, c. 16, Sched. 2, s. 2.

Limitation

(10.1) The rate assistance to be provided to a rate-assisted consumer and the compensation to be provided to a distributor, unit sub-meter provider or any person under this section are subject to the limitation period provided for in the regulations, if any. 2021, c. 34, Sched. 9, s. 11 (5).

Deemed licence conditions, IESO, settlements, payments, etc.

(11) Every licence issued to the IESO, a distributor or unit sub-meter provider or a retailer of electricity shall be deemed to contain conditions requiring the licensee to do anything necessary to implement and administer the provision of rate assistance under this section as may be required by the regulations or the Board, including requirements with respect to,

(a) making payments to the IESO, distributors, unit sub-meter providers and other persons and entities identified by the regulations;

(b) receiving payments or other amounts from the IESO, distributors, unit sub-meter providers and other persons and entities identified by the Minister;

(c) requiring licensees to pass any rate assistance provided for under this section through to rate-assisted consumers in the manner provided for in the regulations;

(d) engaging in settlement activities;

(e) providing information to and receiving information from the Ministry of Energy, the Board, the IESO, distributors, unit sub-meter providers, retailers of electricity and any other prescribed persons and entities in the time and in the manner provided for by the Board or as may be prescribed; and

(f) entering into agreements or arrangements with licensees and other persons. 2017, c. 16, Sched. 2, s. 2.

Information, etc.

(12) If provided for in the regulations, the Board, the IESO, distributors, retailers of electricity and unit sub-meter providers, or any of them, shall provide such information and reports to the Ministry of Energy and to one another as are necessary to facilitate the implementation, administration, funding and delivery of rate-assistance or of anything else required under this section. 2017, c. 16, Sched. 2, s. 2.

Conflicts, etc.

(13) Where any conflict exists between an order of the Board, a code issued by the Board or a licence condition and this section or a regulation made under this section, this section or the regulation made under this section shall prevail to the extent of the conflict. 2017, c. 16, Sched. 2, s. 2.

Regulations

(14**)** The Lieutenant Governor in Council may make regulations governing anything dealt with in this section and without limiting the generality of the foregoing, may make regulations,

(a) governing anything that is described in this section as being prescribed or as being provided for in the regulations or that is required to be done in accordance with the regulations;

(b) governing the time or times at which rate assistance shall be paid or become payable to rate-assisted consumers;

(c) governing the determination of classes of consumers who are rate-assisted consumers, including providing for different classes of rate-assisted consumers;

(d) requiring that certain costs and expenditures related to the Ontario Electricity Support Program be only incurred with the prior approval of the Minister, and governing those costs and expenditures;

(e) establishing rules for the calculation of the amount of the rate assistance to be provided;

(f) governing payments under this section, including determining the method or methods of calculating the amount of rate assistance to be provided;

(g) setting maximum amounts of the total annual value of rate assistance that may be provided;

(h) requiring a distributor, the IESO or a unit sub-meter provider or other prescribed person or entity to make or receive payments in respect of rate assistance, including requiring them to make or receive payments directly to or from the Ministry of Energy or to receive overpayments directly or indirectly from consumers or other persons entitled to receive the rate assistance and prescribing the circumstances in which such payments are to be made and received and such overpayments are to be received as well as methods for determining the amounts payable or to be received;

(i) requiring the IESO to receive payments from the Minister and requiring the IESO to make payments to the Board, to licensed distributors, to unit sub-meter providers or to prescribed persons, in respect of the rate assistance provided under this section and governing methods for determining the amounts payable;

(j) governing the Board's or other prescribed entity's administration and program-related costs in administering the Ontario Electricity Support Program;

(j.1) providing for and governing the limitation period for the purposes of subsection (10.1);

(k) governing transitional matters arising from the changes made to the Ontario Electricity Support Program as a result of the enactment of the *Fair Hydro Act, 2017*. 2017, c. 16, Sched. 2, s. 2; 2021, c. 34, Sched. 9, s. 11 (6).

Retroactivity

(15) A regulation made under this section is, if it so provides, effective with reference to a period before it is filed. 2017, c. 16, Sched. 2, s. 2.

General or particular

(16) A regulation under this section may be general or particular in application, may provide for different classes of persons and entities and may prescribe different rules for different persons or entities or different classes of persons or entities. 2017, c. 16, Sched. 2, s. 2.

Verification of eligibility

(17) Section 11 of the *Ministry of Revenue Act* applies with respect to the Ontario Electricity Support Program as a government assistance program administered by the Board. 2017, c. 16, Sched. 2, s. 2.

Definitions

(18) In this section,

"Government assistance program" has the meaning provided for in subsection 11 (2) of the *Ministry of Revenue Act*; ("programme d'aide gouvernementale")

"rate-assisted consumer" means a consumer referred to in subsection (7). ("consommateur admissible à l'aide tarifaire") 2017, c. 16, Sched. 2, s. 2.

Section Amendments with date in force (d/m/y)

Confidentiality, information sharing, etc.

79.2.1 (1) For the purposes of section 79.2, the Board or the Minister or entity having responsibility for administering the Ontario Electricity Support Program may enter into an agreement with the Minister of Community and Social Services to provide the services to the public listed in subsection (2) on behalf of the Board, Minister or the entity, as the case may be, in relation to the administration of the Ontario Electricity Support Program. 2017, c. 16, Sched. 2, s. 3.

Agreement, etc.

(2) The services that may be included in an agreement referred to in subsection (1) are the following:

1. Providing documents and information about the Ontario Electricity Support Program.

2. Processing applications for the Ontario Electricity Support Program. 2017, c. 16, Sched. 2, s. 3.

Arrangements with others

(3) The Minister of Community and Social Services may arrange with another person or entity to provide, on behalf of that Minister, services that that Minister is authorized to provide under an agreement referred to in subsection (1). 2017, c. 16, Sched. 2, s. 3.

Personal information

(4) The Minister of Community and Social Services is authorized to collect, use, disclose and retain personal information necessary to provide the services authorized by an agreement referred to in subsection (1), but shall not collect, use, disclose or retain more personal information than is reasonably necessary to provide the services. 2017, c. 16, Sched. 2, s. 3.

Limitation

(5) Except where otherwise authorized under subsection (7), the Minister of Community and Social Services shall not collect, use, disclose or retain personal information provided for in subsection (4) without the consent of the individual to whom the information relates. 2017, c. 16, Sched. 2, s. 3.

Duty to transfer personal information

(6) The Minister of Community and Social Services shall transfer an individual's personal information provided for in subsection (4) into the control of the Board, Minister or entity responsible for administering the Ontario Electricity Support Program promptly after processing an application for the Ontario Electricity Support Program, but may retain such personal information as is reasonably necessary to confirm that an individual has been provided a service. 2017, c. 16, Sched. 2, s. 3.

Use of personal information, etc.

(7) The Minister of Community and Social Services may use personal information maintained by that Minister in connection with the administration of the Ontario Disability Support

Program and the program established pursuant to the *Ontario Works Act, 1997*, for the purpose of identifying and contacting individuals eligible for the rate assistance provided under the Ontario Electricity Support Program, and to provide services authorized under an agreement referred to in subsection (1). 2017, c. 16, Sched. 2, s. 3.

Deemed compliance

(8) The use of personal information as allowed by subsection (7) is deemed to comply with section 41 of the *Freedom of Information and Protection of Privacy Act*. 2017, c. 16, Sched. 2, s. 3.

Disclosure of list

(9) In order to assist the Minister of Community and Social Services to identify individuals eligible for rate assistance, the Board or the Minister or entity having responsibility for administering the Ontario Electricity Support Program shall, as soon as practicable after the coming into force of this section, disclose to the Minister of Community and Social Services a list of individuals who are enrolled in the Ontario Electricity Support Program, together with their mailing address and other contact information. 2017, c. 16, Sched. 2, s. 3.

Use of list

(10) The Minister of Community and Social Services may use the information on the list provided under subsection (9) to determine whether an individual who is currently enrolled in the Ontario Disability Support Program or the program established under the *Ontario Works Act, 1997* is also enrolled in the Ontario Electricity Support Program. 2017, c. 16, Sched. 2, s. 3.

Destruction of list

(11) The Minister of Community and Social Services shall destroy the list provided under subsection (9) no later than one year after receiving the list. 2017, c. 16, Sched. 2, s. 3.

Notification about the management of personal information

(12) The Minister of Community and Social Services shall ensure that a notice is published on a website describing,

(a) the purpose for which that Minister collects, uses, discloses and retains personal information in connection with the Ontario Electricity Support Program;

(b) the types of personal information that may be collected, used, disclosed and retained in connection with the Ontario Electricity Support Program, and the circumstances in which the personal information may be collected, used, disclosed and retained in connection with that Program; and

(c) the title, and contact information, including an email address, of an employee who can answer an individual's questions about the use of the personal information under this section. 2017, c. 16, Sched. 2, s. 3.

Section Amendments with date in force (d/m/y)

Distribution rate-protected residential consumers

79.3 (1) The Minister shall provide for distribution rate protection to distribution rate-protected residential consumers having regard to the costs of the distribution of electricity to such consumers with respect to electricity consumed on or after the date prescribed by the regulations. 2017, c. 16, Sched. 2, s. 4.

Money appropriated by the Legislature

(2) The money required for the purposes of the provision of distribution rate protection under this section shall be paid out of the money appropriated for those purposes by the Legislature. 2017, c. 16, Sched. 2, s. 4.

Maximum charge

(3) Despite any order of the Board, or anything else under this Act, where the regulations so provide, a prescribed distributor who distributes electricity to distribution rate-protected residential consumers shall not charge those consumers, or a prescribed class of those consumers, any amount for monthly base distribution charges more than,

(a) the maximum amount for the charge that is provided for in the regulations; or

(b) the amount determined by the Board after applying any calculations, processes or methods provided for in the regulations. 2017, c. 16, Sched. 2, s. 4.

Distributors

(4) A distributor who is prescribed under this section is entitled to be compensated from the money referred to in subsection (2) for lost revenue resulting from the provision of the

distribution rate protection to distribution rate-protected residential consumers under this section. 2017, c. 16, Sched. 2, s. 4.

Information, etc.

(5) If provided for in the regulations, the Board, the IESO and distributors, or any of them shall provide such information and reports to the Ministry of Energy and to one another as are necessary to facilitate the implementation, administration, funding and delivery of distribution rate protection or of anything else required under this section. 2017, c. 16, Sched. 2, s. 4.

Limitation periods for distribution rate protection, consumer

(6) Despite any past entitlement of a consumer who is eligible to distribution rate protection under this section, no distribution rate protection is payable to a consumer after a limitation period prescribed by the regulations in respect of the consumer, other than in such circumstances as may be prescribed by the regulations. 2017, c. 16, Sched. 2, s. 4.

Limitation, reimbursement of distributor, etc.

(7) Despite any requirement under this Act to reimburse a prescribed distributor or other person for distribution rate protection provided by them to distribution rate-protected residential consumers under this section, no amounts for reimbursement are payable to the prescribed distributor or other person after a limitation period prescribed by the regulations in respect of the prescribed distributor or other person, where such reimbursement is based on a consumer's past entitlement under this section which has not yet been paid or reimbursed under this section, other than in such circumstances as may be prescribed by the regulations. 2017, c. 16, Sched. 2, s. 4.

Transitional

(8) If, for technical or operational reasons, a distributor referred to in subsection (3) is unable to adapt its invoices to comply with this section and the regulations by the time it issues its first invoice for electricity consumed after the prescribed date in respect of an account of a consumer who is eligible for distribution rate protection under this section,

(a) the distributor shall adapt its invoices as soon as possible and, in any event, no later than a date prescribed in the regulations; and

(b) consumers continue to be entitled to receive the distribution rate protection to which they are entitled under this Act and may receive it as a lump sum credit on the

invoice for the first billing period after the invoices have been adapted or by such other means as may be prescribed by the regulations. 2017, c. 16, Sched. 2, s. 4.

Regulations

(9) The Lieutenant Governor in Council may make regulations,

(a) prescribing consumers or classes of consumers as distribution rate-protected residential consumers for the purposes of this section;

(b) prescribing dates for the purposes of subsections (1) and (8);

(c) prescribing distributors for the purposes of this section;

(d) governing anything that is described in this section as being prescribed or as being provided for in the regulations or that is required to be done in accordance with the regulations;

(e) governing the provision of distribution rate protection by the Minister in respect of distribution rate-protected residential consumers under this section including determining the method or methods of calculating the amount of rate protection to be provided;

(f) requiring the IESO to receive payments from the Minister and to make payments to licensed distributors, or to persons prescribed by the regulations, in respect of the distribution rate protection provided for under this section and prescribing methods for determining the amounts payable to distributors or distribution rate-protected residential consumers in respect of that protection. 2017, c. 16, Sched. 2, s. 4.

Interpretation

(10) In this section,

"distribution rate-protected residential consumer" has the meaning provided for in the regulations; ("consommateur résidentiel protégé contre les frais de distribution")

"monthly base distribution charges" has the meaning provided for in the regulations. ("frais de distribution mensuels de base") 2017, c. 16, Sched. 2, s. 4.

Section Amendments with date in force (d/m/y)

Delivery credit for on-reserve consumers

79.4 (1) The Minister shall provide a delivery credit to on-reserve consumers who meet the criteria prescribed under this section with respect to electricity consumed on or after the date prescribed by the regulations. 2017, c. 16, Sched. 2, s. 4.

Money appropriated by the Legislature

(2) The money required for the purposes of the provision of the credits required under this section shall be paid out of the money appropriated for those purposes by the Legislature. 2017, c. 16, Sched. 2, s. 4.

Eligible costs

(3) The eligible costs for the delivery credit referred to in subsection (1) are,

(a) the sum of the following charges for which the consumer would otherwise be liable,

(i) all variable and fixed distribution charges,

(ii) all charges based on the retail transmission network service rate,

(iii) all charges based on the retail transmission connection service rate,

(iv) all charges related to losses incurred in the distribution of electricity, except for such amounts that are included in regulatory charges provided for in the regulations, and

(v) any other charges that may be prescribed in the regulations; or

(b) where no separate charges for delivery are provided for by the distributor or other person or entity that may be prescribed in the regulations, the monthly service charge or such other amount as may be prescribed for or in respect of a prescribed distributor. 2017, c. 16, Sched. 2, s. 4.

Delivery credit

(4) A distributor, person or entity shall, unless the regulations provide otherwise, provide the delivery credit referred to in subsection (1) by crediting the account of an on-reserve consumer. 2017, c. 16, Sched. 2, s. 4.

Same

(5) The regulations may require that distributors and any other persons or entities provide a delivery credit to an on-reserve consumer who is entitled to a delivery credit under subsection (1) in such manner or in accordance with such methods as may be prescribed. 2017, c. 16, Sched. 2, s. 4.

Same

(6) A distributor or any person or entity as may be prescribed is entitled to be compensated from the money referred to in subsection (2) for any lost revenue resulting from the provision of the delivery credits under this section. 2017, c. 16, Sched. 2, s. 4.

Information, etc.

(7) If provided for in the regulations, the Board, the IESO and distributors, and other persons or entities, or any of them, shall provide such information and reports to the Ministry of Energy and to one another as are necessary to facilitate the implementation, administration, funding and delivery of the delivery credits or of anything else required under this section. 2017, c. 16, Sched. 2, s. 4.

Limitation periods for delivery credit, consumer

(8) Despite any past entitlement of an on-reserve consumer who is eligible for a delivery credit under this section, no delivery credit is payable to an on-reserve consumer after a limitation period prescribed by the regulations in respect of the on-reserve consumer, other than in such circumstances as may be prescribed by the regulations. 2017, c. 16, Sched. 2, s. 4.

Limitation, reimbursement of distributor, etc.

(9) Despite any requirement under this Act to reimburse a distributor or other persons or entities for delivery credits provided by them to on-reserve consumers under this section, no amounts for reimbursement are payable to the distributor or other persons or entities after a limitation period prescribed by the regulations in respect of the distributor or other persons or entities, where such reimbursement is based on an on-reserve consumer's past entitlement under this section which has not yet been paid or reimbursed under this

section, other than in such circumstances as may be prescribed by the regulations. 2017, c. 16, Sched. 2, s. 4.

Transitional

(10) If, for technical or operational reasons, a distributor referred to in subsection (4) is unable to adapt its invoices to comply with this section and the regulations by the time it issues its first invoice for electricity consumed after the prescribed date in respect of an eligible account,

(a) the distributor shall adapt its invoices as soon as possible and, in any event, no later than a date prescribed in the regulations; and

(b) on-reserve consumers continue to be entitled to receive the delivery credit to which they are entitled under this Act and may receive it as a lump sum credit on the invoice for the first billing period after the invoices have been adapted or by such other means as may be prescribed by the regulations. 2017, c. 16, Sched. 2, s. 4.

Regulations

(11) The Lieutenant Governor in Council may make regulations,

(a) governing who is an on-reserve consumer for the purposes of this section and, without limiting the generality of the foregoing, may provide that consumers who occupy certain areas are on-reserve consumers, and may do so without regard to whether those areas constitute a “reserve” under any other Act or law;

(b) prescribing dates for the purposes of subsections (1) and (10);

(c) governing provision of the delivery credits provided to on-reserve consumers under this section and, without restricting the generality of the foregoing, governing anything that under this section is to be prescribed or provided for in the regulations, or that is to be done in accordance with the regulations;

(d) determining the method or methods of calculating the amount of the delivery credits to be provided by the Minister in respect of on-reserve consumers under this section;

(e) requiring the IESO to make and receive payments to and from the Minister and to make payments to licensed distributors, or to persons prescribed by the regulations, in respect of the delivery credits provided for under this section and prescribing methods for determining the amounts payable to distributors or on-reserve consumers in respect of the credits provided. 2017, c. 16, Sched. 2, s. 4.

Interpretation

(12) In this section,

"on-reserve consumer" has the meaning provided for in the regulations. 2017, c. 16, Sched. 2, s. 4.

Section Amendments with date in force (d/m/y)

Application

79.5 Sections 79.6 through 79.11 apply to the programs provided for under sections 79, 79.2, 79.3 and 79.4 to the extent that they are funded by money appropriated for those purposes by the Legislature. 2017, c. 16, Sched. 2, s. 4.

Section Amendments with date in force (d/m/y)

Definition

79.6 In sections 79.7 to 79.11,

"Finance Minister" means the Minister of Finance or such other member of the Executive Council to whom the administration of those sections is assigned under the *Executive Council Act*. 2017, c. 16, Sched. 2, s. 4.

Section Amendments with date in force (d/m/y)

Records

79.7 (1) Every distributor and every other person prescribed by regulation shall keep at a location in Ontario such records as are necessary to determine and verify compliance with

sections 79, 79.2, 79.3 and 79.4 and the regulations associated with them and any records required by those regulations to be kept. 2017, c. 16, Sched. 2, s. 4.

Electronic records

(2) If a person keeps records in an electronic form, the person shall ensure that, from the time the records are first made and for as long as they are required to be retained,

(a) they remain complete and unaltered, apart from any changes or additions made in the normal course of communication, storage or display; and

(b) they are capable of being printed and of being produced in electronically readable format for inspection, examination or audit. 2017, c. 16, Sched. 2, s. 4.

Retention of records

(3) Records required to be kept under subsection (1) shall not be destroyed unless authorization has been given in writing by the Finance Minister. 2017, c. 16, Sched. 2, s. 4.

Offence

(4) Every person who fails to keep records in accordance with this section is guilty of an offence and, on conviction, is liable to a fine of not less than $50 and not more than $5,000. 2017, c. 16, Sched. 2, s. 4.

Section Amendments with date in force (d/m/y)

Inspections and inquiries

79.8 (1) The Finance Minister may appoint one or more inspectors who are authorized to exercise any of the powers and perform any of the duties of a person authorized by the Minister under subsection 31 (1) of the *Retail Sales Tax Act* for any purpose related to the administration and enforcement of sections 79, 79.2, 79.3 and 79.4 of this Act. 2017, c. 16, Sched. 2, s. 4.

Same

(2) Subsections 31 (1), (2), (2.1) and (2.2) of the *Retail Sales Tax Act* apply, with necessary modifications, with respect to the administration and enforcement of sections 79, 79.2, 79.3 and 79.4 of this Act. 2017, c. 16, Sched. 2, s. 4.

Admission of evidence

(3) The Finance Minister, or a person authorized by the Finance Minister, may, for any purpose related to the administration of sections 79, 79.2, 79.3 and 79.4 or the regulations made in association with them, reproduce from original data stored electronically any information previously submitted as required under those sections or regulations in any form by any person, and the electronically reproduced document shall be admissible in evidence and shall have the same probative force as the original document would have had if it had been proved in the ordinary way. 2017, c. 16, Sched. 2, s. 4.

Inquiry

(4) The Finance Minister may, for any purpose related to the administration of sections 79, 79.2, 79.3 and 79.4 of this Act or the regulations made in association with them, authorize any person, whether or not the person is an employee in the Ministry of the Finance Minister, to make such inquiry as the Finance Minister considers necessary with reference to anything relating to the administration of this Act or the regulations. 2017, c. 16, Sched. 2, s. 4.

Copies

(5) If a book, record or other document is examined or produced under this section, the person by whom it is examined or to whom it is produced or any officer of the Ministry may make, or cause to be made, one or more copies of it, and a document purporting to be certified by the person to be a copy made pursuant to this section is admissible in evidence and has the same probative force as the original document would have if proved in the ordinary way. 2017, c. 16, Sched. 2, s. 4.

Compliance

(6) No person shall hinder or molest or interfere with any person doing anything that the person is authorized by this section to do or prevent or attempt to prevent any person doing any such thing. 2017, c. 16, Sched. 2, s. 4.

Same

(7) Despite any other law to the contrary, every person shall, unless the person is unable to do so, do everything the person is required by this section to do. 2017, c. 16, Sched. 2, s. 4.

Administration of oaths

(8) Declarations or affidavits in connection with statements of information submitted pursuant to this section may be taken before any person having authority to administer an

oath or before any person specially authorized for that purpose by the Lieutenant Governor in Council, but any person so specially authorized shall not charge any fee for doing so. 2017, c. 16, Sched. 2, s. 4.

Application of *Public Inquiries Act, 2009*

(9) Section 33 of the *Public Inquiries Act, 2009* applies to an inquiry under subsection (4). 2017, c. 16, Sched. 2, s. 4.

Section Amendments with date in force (d/m/y)

Recovery of overpayments

Definitions

79.9 (1) In this section,

"inspector" means an inspector referred to in section 79.8; ("inspecteur")

"overpayment" means an amount received by a person in excess of that to which the person is entitled under sections 79, 79.2, 79.3 and 79.4 or the regulations made in association with them. ("trop-perçu") 2017, c. 16, Sched. 2, s. 4.

Notice of overpayment

(2) If it appears to an inspector that a person has received an overpayment, the Finance Minister may send a written notice to the person advising the person of the following:

1. That the person has received an overpayment.

2. The amount of the overpayment and how it was calculated.

3. The required steps to be taken by the person with respect to the overpayment.

4. The date, not more than six months after the date of the notice, by which these steps must be completed.

5. That the Finance Minister has the authority to assess the person for the amount of the overpayment, plus interest, if the person fails to complete the required steps by the

specified date. 2017, c. 16, Sched. 2, s. 4.

Calculation of amount of overpayment

(3) For the purposes of this section, an inspector shall calculate an overpayment or the outstanding balance of an overpayment in the manner and form and using such procedures as the Finance Minister considers adequate and expedient. 2017, c. 16, Sched. 2, s. 4.

Assessment

(4) If a person fails to complete the steps required in a notice under subsection (2) within the time specified in the notice, and any additional time requested by the person and permitted by the Finance Minister, the Finance Minister may assess or reassess the amount of the overpayment, or the outstanding balance of the overpayment, based on the inspector's calculation described in subsection (3). 2017, c. 16, Sched. 2, s. 4.

Penalty

(5) If the Finance Minister makes an assessment or reassessment under subsection (4) and is satisfied that the person's non-compliance with the required steps in the notice was attributable to neglect, carelessness, wilful default or fraud, the Finance Minister may assess a penalty against the person equal to the outstanding balance of the overpayment when the penalty is assessed. 2017, c. 16, Sched. 2, s. 4.

Time limit

(6) The Finance Minister shall not assess or reassess under subsection (4) more than 48 months after the end of the month in which the person received the overpayment. 2017, c. 16, Sched. 2, s. 4.

Exception, where misrepresentation, etc.

(7) Subsection (6) does not apply if the Finance Minister establishes that the person has made a misrepresentation that is attributable to neglect, carelessness or wilful default or has committed any fraud in supplying information under this Act or the regulations or in omitting to disclose information. 2017, c. 16, Sched. 2, s. 4.

Deeming

(8) An amount assessed or reassessed by the Finance Minister under this section is deemed, for the purposes of the administration and enforcement of this Act, to be a debt retirement charge owing and payable, as defined in subsection 85 (1) of the *Electricity Act, 1998,* that has been collected, on the last day of the month in which the person received the overpayment,

by the person as a collector appointed under subsection 85.3 (1) of the *Electricity Act, 1998* and, for those purposes,

(a) sections 85.11, 85.12, 85.14, 85.17 and 85.30 of that Act apply with necessary modifications;

(b) in the application of sections 85.11 and 85.14 of that Act and without limiting the generality of clause (a) of this subsection, references to the Financial Corporation are read as references to the Minister of Finance and references to the Minister of Finance are read as references to the Finance Minister as defined in section 79.6 of this Act;

(c) the regulations made under that Act for the purposes of calculating the rate or rates of interest payable under section 85.11 of that Act and the manner of calculating the amount of interest apply with necessary modifications; and

(d) sections 23 and 36, subsections 37 (1), (1.1) and (2) and sections 37.1, 38 and 39 of the *Retail Sales Tax Act* apply with necessary modifications. 2017, c. 16, Sched. 2, s. 4.

Disposition of repaid amounts

(9) If all or part of an overpayment is repaid to the Finance Minister, the Minister of Energy shall make such financial arrangements and payments as may be necessary to ensure that any person entitled to all or part of the overpayment receives the appropriate amount. 2017, c. 16, Sched. 2, s. 4.

Section Amendments with date in force (d/m/y)

Confidentiality

79.10 (1) Except as authorized by this section, no person employed by the Government of Ontario shall,

(a) knowingly communicate or knowingly allow to be communicated to any person any information obtained by or on behalf of the Minister of Energy or the Finance Minister for the purposes of sections 79, 79.2, 79.3 and 79.4 or the regulations made in association with them; or

(b) knowingly allow any person to inspect or to have access to any record or thing obtained by or on behalf of either Minister for the purposes of this Act. 2017, c. 16, Sched. 2, s. 4.

Testimony

(2) No person employed by the Government of Ontario shall be required, in connection with any legal proceedings,

(a) to give evidence relating to any information obtained by or on behalf of the Minister of Energy or Finance Minister for the purposes of this Act; or

(b) to produce any record or thing obtained by or on behalf of either Minister for the purposes of this Act. 2017, c. 16, Sched. 2, s. 4.

Exception

(3) Subsections (1) and (2) do not apply in respect of,

(a) criminal proceedings under any Act of the Parliament of Canada;

(b) proceedings in respect of the trial of any person for an offence under an Act of the Legislature; or

(c) proceedings relating to the administration or enforcement of this Act or Part V.1 or VI of the *Electricity Act, 1998*. 2017, c. 16, Sched. 2, s. 4.

Communication

(4) A person employed by the Government of Ontario may, in the course of duties in connection with the administration or enforcement of sections 79, 79.2, 79.3 and 79.4 or the regulations made in association with them,

(a) communicate or allow to be communicated to another person employed by the Government of Ontario in the administration or enforcement of any law or to an employee of the Board information obtained by or on behalf of either Minister for the purposes of sections 79, 79.2, 79.3 and 79.4 or the regulations made in association with them; and

(b) allow another person employed by the Government of Ontario in the administration or enforcement of any law or an employee of the Board to inspect or have access to any record or thing obtained by or on behalf of either Minister for the purposes of sections 79, 79.2, 79.3 and 79.4 or the regulations made in association with them. 2017, c. 16, Sched. 2, s. 4.

Reciprocal communication

(5) A person who receives information or obtains access to any record or thing under subsection (4) has a duty to communicate or furnish to that Minister on a reciprocal basis any information, record or thing obtained by the person that affects the administration or enforcement of this Act. 2017, c. 16, Sched. 2, s. 4.

Use of information

(6) Any information, record or thing communicated or furnished under this section may be used only for the administration or enforcement of sections 79, 79.2, 79.3 and 79.4 or the regulations made in association with them or an Act that is administered or enforced by the person receiving the information, record or thing. 2017, c. 16, Sched. 2, s. 4.

Same

(7) The Finance Minister may permit information or a copy of any record or thing obtained by or on behalf of the Finance Minister for the purposes of sections 79, 79.2, 79.3 and 79.4 or the regulations made in association with them to be given to,

(a) the person from whom the information, record or thing was obtained;

(b) any person by whom an amount is payable or has been paid under sections 79, 79.2, 79.3 and 79.4 or the regulations made in association with them; or

(c) the legal representative of a person mentioned in clause (a) or (b) or the agent of the person authorized in writing in that behalf. 2017, c. 16, Sched. 2, s. 4.

Information

(8) The Finance Minister may permit information or a copy of any record or thing obtained by or on behalf of the Finance Minister for the purposes of sections 79, 79.2, 79.3 and 79.4 or the regulations made in association with them to be given to any person employed by any government if,

(a) the information, record or thing obtained by that government for the purpose of any Act that imposes a tax or duty are communicated or furnished on a reciprocal basis to the Minister; and

(b) the information, record or thing will not be used for any purpose other than the administration or enforcement of a law that provides for the imposition of a tax or duty. 2017, c. 16, Sched. 2, s. 4.

Offence

(9) Every person who contravenes any provision of this section is guilty of an offence and on conviction is liable to a fine of not more than $2,000. 2017, c. 16, Sched. 2, s. 4.

Section Amendments with date in force (d/m/y)

Offences

False statements, etc., and fraud

79.11 (1) Every person who engages in any of the following acts or omissions is guilty of an offence:

1. Making, participating in, assenting to or acquiescing in the making of a false or deceptive statement in any document or answer required or submitted under sections 79, 79.2, 79.3 and 79.4 or the regulations made in association with them.

2. Destroying, altering, mutilating, hiding or otherwise disposing of information or records of any person, for the purpose of evading compliance with sections 79, 79.2, 79.3 and 79.4 or the regulations made in association with them.

3. Making, assenting to or acquiescing in the making of a false or deceptive entry of a material particular in a record of any person required to maintain records for the purposes of sections 79, 79.2, 79.3 and 79.4 or the regulations made in association with them.

4. Omitting to make or assenting to or acquiescing in the omission of an entry of a material particular in a record of any person required to maintain records for the

purposes of sections 79, 79.2, 79.3 and 79.4 or the regulations made in association with them.

5. Wilfully evading or attempting to evade, in any manner, compliance with an obligation under sections 79, 79.2, 79.3 and 79.4 or the regulations made in association with them. 2017, c. 16, Sched. 2, s. 4.

Penalty upon conviction

(2) A person convicted of an offence under subsection (1) is liable to either or both of the following penalties in addition to any other penalty assessed under this Act:

1. A fine in an amount that is not less than $1,000 and not more than $10,000.

2. Imprisonment for a term of not more than two years. 2017, c. 16, Sched. 2, s. 4.

General offence

(3) Every person who contravenes, by any act or omission, any other requirement imposed under sections 79, 79.2, 79.3 and 79.4 is guilty of an offence and, on conviction, is liable, where no other penalty is provided for the offence, to a fine of not less than $50 and not more than $5,000. 2017, c. 16, Sched. 2, s. 4.

Limitation period

(4) A proceeding to prosecute an offence provided for in this section must be commenced within six years after the date on which the matter of the offence arose. 2017, c. 16, Sched. 2, s. 4.

Payment of fines

(5) Fines imposed on conviction of an offence provided for in this section are payable to the Finance Minister on behalf of the Crown in right of Ontario. 2017, c. 16, Sched. 2, s. 4.

Section Amendments with date in force (d/m/y)

79.12 REPEALED: 1998, c. 15, Sched. B, s. 79.11.

Section Amendments with date in force (d/m/y)

79.13 REPEALED: 1998, c. 15, Sched. B, s. 79.11.

Section Amendments with date in force (d/m/y)

79.14 REPEALED: 1998, c. 15, Sched. B, s. 79.11.

Section Amendments with date in force (d/m/y)

79.15 REPEALED: 1998, c. 15, Sched. B, s. 79.11.

Section Amendments with date in force (d/m/y)

Commodity price for electricity: low volume consumers, etc.

79.16 (1) Despite any order under section 78 and, subject to subsection (7), despite any agreement to the contrary entered into or renewed on or before December 9, 2002, the rates for electricity payable by a consumer who is a member of a class of consumers prescribed by the regulations for the purposes of this section are,

(a) with respect to electricity used on or after the day this subsection comes into force and before the day prescribed by the regulations for the purposes of this subsection, the price determined in accordance with the regulations; and

(b) with respect to electricity used on or after the day prescribed by the regulations for the purposes of this subsection, the rates determined by the Board in accordance with the regulations. 2004, c. 23, Sched. B, s. 25.

Same

(2) The Board shall not make any rate determinations for the purposes of clause (1) (b) unless a regulation has been made under clause 88 (1) (z.8). 2004, c. 23, Sched. B, s. 25.

(3) REPEALED: 2017, c. 16, Sched. 1, s. 44 (4).

Exception: consumers who file statement

(4) Subsection (1) does not apply to a consumer if,

(a) the consumer indicates in a written statement that the consumer does not wish to have subsection (1) apply and the consumer files the written statement with,

(i) the distributor with whom the consumer has an account, if the consumer is not a market participant, or

(ii) the IESO, if the consumer is a market participant; and

(b) at the time the statement is filed under clause (a), a regulation prescribing criteria for the purpose of this clause is in force and those criteria are met. 2004, c. 23, Sched. B, s. 25.

Application of subs. (1)

(5) Subsection (1) does not apply to a consumer to whom electricity is distributed through a distribution system that is not connected to the IESO-controlled grid. 2004, c. 23, Sched. B, s. 25.

Exception: service transaction request, contract entered into after December 9, 2002

(6) If a consumer enters into or renews a contract after December 9, 2002 with respect to which a service transaction request as defined in the Retail Settlement Code is or has been implemented to enable the consumer to purchase electricity from a competitive retailer as defined in the Retail Settlement Code, subsection (1) does not apply to the consumer during the term of the contract. 2004, c. 23, Sched. B, s. 25.

Contracts entered into after December 9, 2002

(7) Subject to subsection (6), the commodity price for electricity payable by a consumer under subsection (1) is subject to any contract the consumer renews or enters into after December 9, 2002. 2004, c. 23, Sched. B, s. 25.

Same

(8) A consumer who enters into or renews a retail contract for electricity after the date prescribed for the purposes of subsection (1) or becomes subject to a rate approved or fixed by the Board under this section is subject to such conditions as may be determined by the Board. 2004, c. 23, Sched. B, s. 25.

Repeal

(9) This section is repealed on a day to be named by proclamation of the Lieutenant Governor. 2004, c. 23, Sched. B, s. 25.

Section Amendments with date in force (d/m/y)

Form of invoice for prescribed classes of consumers

79.17 (1) The Minister may require that invoices issued in respect of electricity to consumers who are members of a class of consumers prescribed by the regulations meet requirements to be prescribed by the regulations or be in a form approved by the Minister. 2010, c. 8, s. 38 (18).

Different forms

(2) The regulations may prescribe or the Minister may approve different requirements for invoices and may prescribe or specify the circumstances in which each requirement shall apply or be used and the Minister may approve different forms of invoices and the circumstances under which the forms are to be used. 2010, c. 8, s. 38 (18).

Errors

(3) No defect, error or omission in the form or substance of an invoice issued in respect of electricity to a consumer referred to in subsection (1) invalidates any proceeding for the recovery of the amount payable under the invoice. 2004, c. 23, Sched. B, s. 26.

Section Amendments with date in force (d/m/y)

Prohibition, generation by transmitters or distributors

80 No transmitter or distributor or affiliate of a transmitter or distributor shall acquire an interest in a generation facility in Ontario, construct a generation facility in Ontario or purchase shares of a corporation that owns a generation facility in Ontario unless it has first given notice of its proposal to do so to the Board and the Board,

(a) has not issued a notice of review of the proposal within 60 days of the filing of the notice; or

(b) has approved the proposal under section 82. 1998, c. 15, Sched. B, s. 80.

Prohibition, transmission or distribution by generators

81 No generator or affiliate of a generator shall acquire an interest in a transmission or distribution system in Ontario, construct a transmission or distribution system in Ontario or

purchase shares of a corporation that owns a transmission or distribution system in Ontario unless it has first given notice of its proposal to do so to the Board and the Board,

(a) has not issued a notice of review of the proposal within 60 days of the filing of the notice; or

(b) has approved the proposal under section 82. 1998, c. 15, Sched. B, s. 81.

Review of acquisition

82 (1) If the Board has issued a notice of review under section 80 or 81, it shall expeditiously proceed to review the proposal. 1998, c. 15, Sched. B, s. 82 (1).

Order

(2) The Board shall make an order approving a proposal described in section 80 if it determines that,

(a) the impact of the proposal would not adversely affect the development and maintenance of a competitive market and the proposal is not inconsistent with the objectives of the Board or the purposes of the *Electricity Act, 1998*; or

(b) the proposal is required to maintain the reliability of the transmission or distribution system of the relevant transmitter or distributor. 2017, c. 2, Sched. 10, s. 2 (6).

Same

(3) The Board shall make an order approving a proposal described in section 81 if it determines that,

(a) the impact of the proposal would not adversely affect the development and maintenance of a competitive market; and

(b) the proposal is not inconsistent with the objectives of the Board or the purposes of the *Electricity Act, 1998*. 2017, c. 2, Sched. 10, s. 2 (7).

Condition for making order

(4) Unless the Board makes the determination described in subsection (2) or (3), it shall not make an order approving a proposal described in section 80 or 81, respectively. 1998, c. 15, Sched. B, s. 82 (4).

Section Amendments with date in force (d/m/y)

Exemptions

82.1 (1) The Board may, without a hearing, establish criteria exempting one or more classes of transactions or construction activities from the application of section 80 or 81. 2017, c. 2, Sched. 10, s. 2 (8).

No notice if exempt

(2) A person is not required to give notice of a proposal under section 80 or 81 if the proposal meets the criteria established by the Board under subsection (1). 2017, c. 2, Sched. 10, s. 2 (8).

Section Amendments with date in force (d/m/y)

Standards, targets and criteria

83 (1) The Board may establish standards, targets and criteria for evaluation of performance by generators to whom section 78.1 applies, transmitters, distributors and retailers. 1998, c. 15, Sched. B, s. 83 (1); 2004, c. 23, Sched. B, s. 27 (1).

Regard for standards, targets

(2) The Board may have regard to the standards, targets and criteria referred to in subsection (1) in exercising its powers and performing its duties under this or any other Act in relation to generators to whom section 78.1 applies, transmitters, distributors and retailers, including establishing the conditions of a licence. 1998, c. 15, Sched. B, s. 83 (2); 2004, c. 23, Sched. B, s. 27 (2).

Section Amendments with date in force (d/m/y)

Distinction between transmission and distribution, determination

84 In making a decision in any proceeding under this Part or under the *Electricity Act, 1998*, the Board may determine that,

(a) a system or part of a system that forms part of a transmission system is a distribution system or part of a distribution system; and

(b) a system or part of a system that forms part of a distribution system is a transmission system or part of a transmission system. 1998, c. 15, Sched. B, s. 84; 2003, c. 3, s. 53.

Section Amendments with date in force (d/m/y)

85 REPEALED: 2003, c. 3, s. 54.

Section Amendments with date in force (d/m/y)

Change in ownership or control of systems

86 (1) No transmitter or distributor, without first obtaining from the Board an order granting leave, shall,

(a) sell, lease or otherwise dispose of its transmission or distribution system as an entirety or substantially as an entirety;

(b) sell, lease or otherwise dispose of that part of its transmission or distribution system that is necessary in serving the public; or

(c) amalgamate with any other corporation. 2003, c. 3, s. 55 (1).

Same

(1.1) Subsection (1) does not apply with respect to a disposition of securities of a transmitter or distributor or of a corporation that owns securities in a transmitter or distributor. 2002, c. 1, Sched. B, s. 9 (1).

Acquisition of share control

(2) No person, without first obtaining an order from the Board granting leave, shall,

(a) acquire such number of voting securities of a transmitter or distributor that together with voting securities already held by such person and one or more affiliates or associates of that person, will in the aggregate exceed 10 per cent of the voting securities of the transmitter or distributor; or

(b) acquire control of any corporation that holds, directly or indirectly, more than 10 per cent of the voting securities of a transmitter or distributor if such voting securities constitute a significant asset of that corporation. 1998, c. 15, Sched. B, s. 86 (2); 2015, c. 29, s. 15 (1, 2).

Same

(2.1) Subsection (2) does not apply to,

(a) the Crown in right of Ontario;

(b) an underwriter (within the meaning of the *Securities Act*) who holds the voting securities solely for the purpose of distributing them to the public;

(c) any person or entity who is acting in relation to the voting securities solely in the capacity of an intermediary in the payment of funds or the delivery of securities or both in connection with trades in securities and who provides centralized facilities for the clearing of trades in securities; or

(d) any person or entity who holds the voting securities by way of security only. 2002, c. 1, Sched. B, s. 9 (2).

Significant asset

(3) For the purposes of subsection (2),

(a) an asset is a significant asset if its value is 10 per cent or more of the aggregate book value of the total assets of a person, determined on a consolidated basis in accordance with generally accepted accounting principles; and

(b) "control", with respect to a corporation, has the same meaning as in the *Business Corporations Act*. 1998, c. 15, Sched. B, s. 86 (3); 2015, c. 29, s. 15 (3).

Valuation of voting securities

(4) For the purpose of determining whether voting securities constitute a significant asset, the value of the voting securities shall be deemed to be,

(a) the market value of the securities if more than 10 per cent of the voting securities are publicly traded; and

(b) 115 per cent of the book value of the voting securities, as determined by the equity method of accounting, in all other cases. 1998, c. 15, Sched. B, s. 86 (4); 2015, c. 29, s. 15 (4).

Mortgages

(5) This section does not apply to a mortgage or charge to secure any loan or indebtedness or to secure any bond, debenture or other evidence of indebtedness. 1998, c. 15, Sched. B, s. 86 (5).

Transactions under *Electricity Act, 1998*

(5.1) This section does not apply with respect to a transaction described in section 50.1 or 50.2 of the *Electricity Act, 1998*. 2002, c. 1, Sched. B, s. 9 (2).

Leave

(6) An application for leave under this section shall be made to the Board, which shall grant or refuse leave. 1998, c. 15, Sched. B, s. 86 (6).

Void agreement

(6.1) An amalgamation agreement between the corporations that propose to amalgamate is void if the Board refuses to grant leave under this section, even if the amalgamation agreement has been adopted in accordance with subsection 176 (4) of the *Business Corporations Act*. 2003, c. 3, s. 55 (2).

Void certificate

(6.2) A certificate of amalgamation endorsed by the director appointed under section 278 of the *Business Corporations Act* is void if it is endorsed before leave of the Board for the amalgamation is granted. 2003, c. 3, s. 55 (2).

Sale of assets of OEFC to or by Hydro One Inc., etc.

(7) Despite subsection (1) and any order of the Board, the sale, lease, conveyance, transfer, assignment, assumption or other disposition of any of the assets, rights, liabilities or obligations of the Ontario Electricity Financial Corporation to or by Hydro One Inc. or a subsidiary of Hydro One Inc. after March 31, 1999, including any such sale, lease, conveyance, transfer, assignment, assumption or other disposition completed before this subsection came into force, does not require an order from the Board granting leave. 2002, c. 23, s. 4 (13).

Section Amendments with date in force (d/m/y)

Board to monitor markets

87 (1) The Board shall monitor markets in the electricity sector and may report to the Minister on the efficiency, fairness, transparency and competitiveness of those markets. 1998, c. 15, Sched. B, s. 87 (1).

Board to advise Minister

(2) The Board shall advise the Minister with respect to any of the following matters if requested by the Minister to do so or if the Board considers it advisable to do so:

1. Any abuse or potential abuse of market power in the electricity sector.

2. The circumstances giving rise to or that is capable of giving rise to unintended outcomes or effects that operate contrary to the interests of competition. 2004, c. 23, Sched. B, s. 28.

Section Amendments with date in force (d/m/y)

Regulations, electricity licences

88 (1) The Lieutenant Governor in Council may make regulations,

(a) prescribing requirements for a licence which allows for the retailing of electricity to residential or small business consumers, as defined in the regulations, which, if not met, will result in the refusal to issue or renew a licence;

(a.0.1) for the purposes of section 57.1,

(i) providing for conditions or restrictions on the Board's power to make orders under that section, including limiting the number of times an exemption may be extended under subsection 57.1 (3), and

(ii) governing criteria for pilot and demonstration projects, which may include criteria respecting the manner in which a project is funded;

(a.0.2) prescribing classes of consumers for the purposes of section 58;

(a.1) providing for the establishment, administration and operation of a tracking system to associate electricity with the processes and fuel types used by generation facilities and with the types and quantities of contaminants emitted by generation facilities, including,

(i) designating the administrator of the tracking system and prescribing the administrator's powers and duties,

(ii) designating a person or body to audit the tracking system and the information used by the tracking system and prescribing the auditor's powers and duties, including powers to enter business premises and inspect documents and records,

(iii) requiring persons prescribed by the regulations to submit information prescribed by the regulations or by the administrator or auditor of the tracking system to the administrator or auditor in a form and at times specified by the regulations or by the administrator or auditor,

(iv) protecting the administrator of the tracking system from liability arising from incorrect information provided by other persons,

(v) requiring the administrator or auditor of the tracking system or the Minister to make determinations for the purposes of the tracking system,

(vi) requiring information from the tracking system to be made available to the public,

(vii) requiring persons prescribed by the regulations to provide other persons prescribed by the regulations with information from the tracking system in a form and at times specified by the regulations or by the administrator or auditor of the tracking system,

(viii) authorizing and governing the issuance of certificates related to determinations made for the purposes of the tracking system, and

(ix) authorizing the administrator of the tracking system, subject to the approval of the Board, to establish and charge fees in connection with the tracking system, and governing the establishment and charging of those fees;

(b) requiring retailers or generators or persons engaged in an activity described in clause 57 (f) to make timely disclosure to the Minister of the Environment, or the IESO in the manner and at the times prescribed, of the nature and quantity of the prescribed contaminants emitted by the generation facility from which the electricity being sold or offered for sale is produced or deemed to be produced, the nature of the fuel and the process of generation used at the facility;

(c) authorizing the Minister of the Environment to determine from which generation facility or facilities electricity is deemed to be produced in accordance with such rules as may be prescribed in the regulation;

(d) requiring retailers or generators or persons engaged in an activity described in clause 57 (f) to file with the Board, in such form and at such times as the Board may determine, evidence that the generation facility from which the electricity is produced or is deemed to be produced meets standards for emission of prescribed contaminants from a source or class of sources set out under the *Environmental Protection Act*;

(e) respecting the manner in which reductions, credits or allowances acquired by a retailer, generator or a person engaged in an activity described in clause 57 (f) under the *Environmental Protection Act* may be used in determining whether there has been compliance with the standards referred to in clause (d);

(f) requiring retailers to make timely disclosure to consumers, in the manner and at the times prescribed, of the nature and quantity of the prescribed contaminants emitted by the generation facility from which the electricity being sold or offered for sale is produced or is deemed to be produced, the nature of the fuel and the process of generation used at the facility and such other information as is prescribed;

(g) delegating to a body the power to establish the manner and time requirements described in clause (f) and requiring retailers to disclose the information described in that clause in that manner and within those time periods;

(g.1) requiring a distributor, in the circumstances and in the manner prescribed by the regulations, to subtract the amount of electricity conveyed into the distribution system by a generator from the amount consumed from the system by the generator, for billing purposes, if the generator generates electricity primarily for the generator's own use;

(g.2) for the purposes of clause 70 (2) (d.1), prescribing matters which may be included as a licence condition in a licence of a retailer of electricity in relation to the retailing of electricity;

(g.3) for the purposes of subsection 71 (1), providing for circumstances in which a transmitter or distributor may carry on a business activity other than transmitting or distributing electricity other than through one or more affiliates, subject to any conditions or restrictions specified by the regulations;

(g.3.1) prescribing rules for the purposes of subsection 71 (2);

(g.3.2) governing,

(i) the capacity of a renewable energy generation facility referred to in clause 71 (3) (a) and criteria for a renewable energy generation facility for the purposes of clause 71 (3) (a),

(ii) criteria for a generation facility that uses technology that produces power and thermal energy from a single source for the purposes of clause 71 (3) (b), and

(iii) criteria for an energy storage facility for the purposes of clause 71 (3) (c);

(g.4) prescribing different situations for which separate rates must be approved or fixed under section 78, with those situations being defined with reference to amounts of electricity used and times when electricity is used;

(g.5) governing the approving or fixing under section 78 of just and reasonable rates for the retailing of electricity in order to meet a distributor's obligations under section 29 of the *Electricity Act, 1998*, including prescribing methods of and procedures for approving or fixing rates, including requiring persons licensed under this Part to participate in those methods and procedures and to enter into contracts or other arrangements as part of those methods and procedures;

(g.6) prescribing different classes of consumers for the purposes of section 78 and the date or method of determining the date on which rates approved or fixed for a class of consumers take effect;

(g.6.0.1) prescribing circumstances under which a transmitter or distributor shall bear the costs of construction, expansion or reinforcement associated with the connection of a renewable energy generation facility to the transmitter's transmission system or the distributor's distribution system;

(g.6.0.2) for the purposes of subsection 78 (3.0.0.1), prescribing rules in relation to the approving or fixing of just and reasonable rates for unit smart metering that the Board must follow, prescribing classes of consumers for the purposes of clause 78 (3.0.0.1) (a) and prescribing circumstances for the purposes of clause 78 (3.0.0.1) (b);

(g.6.1) prescribing the circumstances in which the Board may make orders permitting the Smart Metering Entity or distributors to establish deferral or variance accounts for the purposes of subsection 78 (3.0.2);

(g.6.2) in respect of orders relating to the ability of the Smart Metering Entity, distributors, retailers and other persons to recover costs associated with the smart metering initiative for the purposes of subsection 78 (3.0.3);

(g.7) governing the approving or fixing under subsection 78 (3.1) of rates for the retailing of electricity, including,

(i) prescribing rules for the purposes of subsection 78 (3.1), and

(ii) prescribing matters for the purposes of subsection 78 (3.4) to be taken into consideration in forecasting the cost of electricity and the methods of and procedures for forecasting the cost of electricity, including the treatment of any outstanding balances in variance accounts held by the IESO;

(g.8) prescribing conditions for the purposes of subsection 78 (3.5);

(g.9) providing for penalties and fines a transmitter or distributor is required to pay under an Act that the Board may include in approving or fixing rates for the

transmission or distribution of electricity, for the purposes of paragraph 1 of subsection 78 (5);

(g.10) Repealed: 2023, c. 9, Sched. 24, s. 6 (2).

(h) prescribing, for the purposes of subsection 78 (5.1), methods and techniques for the calculation and treatment of transfers made by Hydro One Inc. or its subsidiary, as the case may be, that are authorized by section 50.1 of the *Electricity Act, 1998*;

(i) prescribing, for the purposes of subsection 78 (5.2), methods and techniques for the treatment of the statutory right to use corridor land;

(i.1) prescribing generators and generation facilities and units for the purposes of section 78.1;

(i.2) prescribing generators or generation facilities and units at generation facilities whose generators may apply to the Board for an order that section 78.1 applies to the facility or unit and rules governing the procedure for applying, the criteria to be satisfied and any terms and limitations that must or may be included in the order;

(i.3) governing circumstances in which payments shall not be made under section 78.1;

(i.4) for the purposes of subsection 78.1 (3.2), specifying amounts relating to Ontario Power Generation Inc.'s activities under Part II.1 of the *Electricity Act, 1998* that shall not be included in a payment to it under section 78.1, including providing for methods for determining the amounts;

(i.5) Repealed: 2014, c. 7, Sched. 23, s. 12 (2).

(i.6) governing the determination of payment amounts by the Board under section 78.1, including rules prescribing,

(i) methods of and procedures for determining payment amounts,

(ii) financial factors which the Board may take into consideration in determining payment amounts, and

(iii) different payment amounts or different methods of and procedures for determining payment amounts for different situations, including situations defined with respect to energy sources, time of generation and amounts of electricity generated;

(i.7) authorizing or requiring generators to establish one or more variance or deferral accounts in connection with section 78.1;

(i.8) prescribing generation facilities for the purposes of section 78.2;

(i.9) prescribing rules for determining the amount of the Financial Corporation's indirect costs in respect of a contract for the purposes of section 78.2;

(i.10), (i.11) Repealed: 2014, c. 7, Sched. 23, s. 12 (3).

(j) governing all matters relating to payment amounts under section 78.5;

(k)-(o) Repealed: 1998, c. 15, Sched. B, s. 79.1 (24).

(p), (q) Repealed: 1998, c. 15, Sched. B, s. 79.2 (5).

(r) Repealed: 1998, c. 15, Sched. B, s. 79.11.

(r.1) Repealed: 1998, c. 15, Sched. B, s. 79.11.

(r.2) Repealed: 1998, c. 15, Sched. B, s. 79.11.

(s)-(y) Repealed: 1998, c. 15, Sched. B, s. 79.11.

(z) Repealed: 2004, c. 23, Sched. B, s. 29 (9).

(z.1) - (z.5) Repealed: 1998, c. 15, Sched. B, s. 79.11.

(z.6) prescribing classes of consumers for the purposes of section 79.16;

(z.7) prescribing prices or methods for determining prices for the purpose of clause 79.16 (1) (a), including prescribing separate prices or methods for different situations,

including situations defined with respect to types of consumers and amounts of electricity used;

(z.8) governing the determination of rates by the Board under clause 79.16 (1) (b), including,

(i) prescribing methods of and procedures for determining rates, including requiring persons licensed under this Part to participate in those methods and procedures and to enter into contracts or other arrangements as part of those methods and procedures, and

(ii) prescribing different situations for which separate rates must be determined, including situations defined with respect to types of consumers, amounts of electricity used and times when electricity is used;

(z.9) prescribing a date for the purpose of subsection 79.16 (1);

(z.10) prescribing criteria for the purposes of clause 79.16 (4) (b);

(z.11) for the purposes of section 79.17, prescribing,

(i) classes of consumers,

(ii) information that must or may be included on invoices issued in respect of electricity to consumers in one or more of the prescribed classes,

(iii) the requirements that the invoices must meet, and

(iv) the form of the invoice, including prescribing different requirements and forms for the purposes of that section;

(z.12) respecting the manner in which invoices issued in respect of electricity to consumers who are members of a class of consumers prescribed for the purposes of section 79.17 are to be provided to those consumers. 1998, c. 15, Sched. B, s. 88 (1) [see also ss. 79.1 (24), 79.2 (5), 79.11]; 2002, c. 1, Sched. B, s. 10; 2002, c. 23, s. 4 (14-17); 2003, c. 3, s. 56 (1, 2); 2003, c. 8, s. 11; 2004, c. 23, Sched. B, s. 29 (1-11); 2006, c. 3, Sched. C, s. 6; 2009, c. 12, Sched. D, s. 15; 2010, c. 8, s. 38 (19, 20); 2014, c. 7, Sched. 23, s. 12; 2019,

c. 4, Sched. 4, s. 2; 2021, c. 2, Sched. 2, s. 6 (1, 2); 2022, c. 23, Sched. 1, s. 6; 2023, c. 9, Sched. 24, s. 6 (1, 2).

Net metering, single generator

(1.1) The Lieutenant Governor in Council may make regulations,

(a) requiring a distributor mentioned in clause (1) (g.1) to apply any credit resulting from the application of a regulation made under that clause in accordance with such methods or criteria as may be prescribed;

(b) prescribing the methods or criteria mentioned in clause (a), which may include limiting or prohibiting the application or recognition of any credit in a manner which results in the reduction of fixed charges on an invoice. 2017, c. 34, Sched. 31, s. 2 (1).

Subdelegation

(1.2) A regulation made under clause (1) (g.9) may authorize the Board to determine a matter that may be prescribed by the Lieutenant Governor in Council under that clause. 2021, c. 2, Sched. 2, s. 6 (3); 2023, c. 9, Sched. 24, s. 6 (3).

Retroactive

(2) A regulation made under clause (1) (i.5), (i.9) or (z.7) may apply in respect of an amount payable before the day the regulation is filed. 2004, c. 23, Sched. B, s. 29 (12).

Same

(2.0.1) A regulation made under clause (1) (i.8), (i.9), (i.10) or (i.11) may apply with respect to a period before it is filed. 2004, c. 23, Sched. B, s. 29 (12).

Conflict with market rules

(2.0.2) In the event of a conflict, a regulation made under clause (1) (i.5), (i.6), (i.9), (i.10) or (i.11) prevails over the market rules to the extent of the conflict. 2004, c. 23, Sched. B, s. 29 (12).

Net metering, other arrangements

(2.1) The Lieutenant Governor in Council may make regulations,

(a) requiring a distributor, in prescribed circumstances and in the prescribed manner, to subtract the amount of electricity conveyed into the distribution system by a generator

from the amount consumed from the system by a consumer, for billing purposes, if the generator and the consumer have entered into an agreement that meets the prescribed criteria;

(b) authorizing distributors and other persons to implement, in prescribed circumstances and in the prescribed manner, prescribed pilot or demonstration projects for the purpose of subtracting some or all of the electricity conveyed into a distribution system by one or more generators within one or more distributors' service areas from the amount consumed from a distribution system by one or more consumers, for billing purposes, where the distributor, generator and other person, if any, and consumers to be billed as part of the project have entered into an agreement that meets prescribed criteria;

(c) governing agreements mentioned in clauses (a) and (b);

(d) requiring distributors to apply any credit to consumers resulting from a regulation made under clause (a) or (b) in accordance with such methods or criteria as may be prescribed;

(e) prescribing the methods or criteria mentioned in clause (d), which may include limiting or prohibiting the application or recognition of any credit in a manner which results in the reduction of fixed charges on a consumer's invoice. 2017, c. 34, Sched. 31, s. 2 (2).

Agreements

(2.2) For the purposes of clause (2.1) (a), a consumer may enter into agreements with more than one generator in respect of one or more generation facilities. 2017, c. 34, Sched. 31, s. 2 (2).

Regulations, Minister

(2.3) The Minister may make regulations providing for amounts and classes of amounts a transmitter or distributor is required to pay that shall not be included in approving or fixing rates for the transmission or distribution of electricity, for the purposes of paragraph 2 of subsection 78 (5). 2023, c. 9, Sched. 24, s. 6 (4).

General or particular

(3) A regulation under this section may be general or particular in its application. 1998, c. 15, Sched. B, s. 88 (3).

---

v Section Amendments with date in force (d/m/y)

88.0.1 Repealed: 2014, c. 7, Sched. 23, s. 13.

---

v Section Amendments with date in force (d/m/y)

PART V.1
GAS MARKETERS AND RETAILERS OF ELECTRICITY — STANDARDS AND AUDITS

Licences

88.1 (1) A licence issued under Part IV or V,

(a) shall contain such conditions as may be prescribed by regulation; and

(b) may contain such other conditions provided by an order of the Board or any rule or code issued by the Board. 2010, c. 8, s. 38 (21).

Same

(2) For the purposes of subsection (1), a regulation may specify criteria, conditions or requirements that must or that may be included as a condition of licence in any licence issued to a gas marketer or a retailer of electricity, including criteria, conditions or requirements relating to the following:

1. The operations, management and business practices of a gas marketer or retailer of electricity, including but not limited to the conduct of employees, agents or third parties acting on behalf of the gas marketer or retailer of electricity.

2. The activities, conduct or practices that must, may or may not be undertaken by the gas marketer or retailer of electricity, its employees, agents or third parties acting on behalf of the gas marketer or retailer of electricity.

3. The establishment of an assurance fund within each gas marketer or retailer of electricity, including,

i. criteria and requirements as to the amount that the gas marketer or retailer of electricity is required to maintain in the fund or a method for determining the amount, and

ii. the circumstances governing how the amount is to be contributed to the fund by the gas marketer or retailer of electricity and the times at which and the circumstances under which contributions are to be made and the amount is to be maintained.

4. Standards that are required to be met by a gas marketer or a retailer of electricity or its employees, agents or third parties acting on behalf of the gas marketer or retailer of electricity, including standards related to,

i. education, training, certifications and communications,

ii. business practices,

iii. performance standards,

iv. background verifications and assessments as required under paragraph 7,

v. record keeping,

vi. contracting, including standards related to contracting with prescribed consumers or prescribed classes of consumers, and

vii. such other matters as may be prescribed by regulation.

5. Information that is to be provided orally or in writing by a gas marketer or retailer of electricity or its employees, agents or third parties acting on its behalf to a consumer or a member of a class of consumers prescribed by regulation, the Board, the Ministry or to such other person or entity as may be prescribed by regulation and the circumstances in which the information must be provided and the time or times within which such information must be provided.

6. Identification, including criteria or requirements related to the identification credentials or badges or other forms of identification provided to the employees, agents or third parties acting on behalf of the gas marketer or retailer of electricity.

7. Background verification and assessment of the employees, agents or third parties acting on behalf of the gas marketer or retailer of electricity, including the requirement to establish a process or processes to conduct the verifications and assessments and the criteria and requirements for the time or times at which the verification and assessments must be performed.

8. The establishment of processes related to employees, agents or third parties acting on behalf of the gas marketer or retailer of electricity, including the prescribing of conditions, requirements or criteria to be met by such processes, for the following activities:

i. Business related activities, including,

A. licensing, including renewal, suspension and cancellation of licences,

B. bonding and insurance,

C. examination for prescribed credentials, certificates, accreditations or designations,

D. creation of codes of conduct, best practices and policies,

E. requirements in relation to independence from or permissible investment in or association with a gas marketer or retailer of electricity or another licensee, and

F. such other matters as may be prescribed by regulation.

ii. The conduct of activities referred to in this section in relation to each of the employees, agents or third parties acting on behalf of the gas marketer or retailer of electricity at such times as may be prescribed by regulation.

iii. Ensuring that the employees, agents or third parties acting on behalf of the gas marketer or retailer of electricity adhere to the processes referred to in this section and, in particular, obtain any prescribed credentials.

9. Requirements or provisions that must be included in any arrangements or agreements relating to retailing of electricity or gas marketing in Ontario, including arrangements or agreements relating to retailing of electricity or gas marketing to consumers or to classes of consumers prescribed by regulation. Such requirements or provisions may be general or specific in nature. 2010, c. 8, s. 38 (21).

Section Amendments with date in force (d/m/y)

Licensing employees, etc.

88.2 (1) Where a regulation made under this Act so requires, the Board shall license the following persons and the regulation may specify conditions, criteria or requirements that must or may be included in a licence issued to the person:

1. Employees of a gas marketer or retailer of electricity or members of classes of such employees prescribed by regulation.

2. Employees of third parties acting on behalf of gas marketers or retailers of electricity or members of classes of such employees prescribed by regulation. 2010, c. 8, s. 38 (21).

Processes, etc.

(2) For the purposes of subsection (1), any process established by the Board to license the employees referred to in that subsection shall meet the criteria or requirements prescribed by regulation. 2010, c. 8, s. 38 (21).

Section Amendments with date in force (d/m/y)

Powers of audit

88.3 (1) The Board may appoint a person who meets the criteria as may be prescribed by regulation to audit the compliance of a gas marketer or retailer of electricity or its agents or employees with the requirements of,

(a) any condition of a licence referred to in section 48 or 57; or

(b) an enforceable provision. 2010, c. 8, s. 38 (21).

Time for audit

(2) The Board may authorize the person appointed to audit compliance to conduct the audit at such time as the Board may require. 2010, c. 8, s. 38 (21).

Audit, without notice

(3) Where the Board authorizes a person to audit the compliance of a gas marketer or retailer of electricity, the Board may do so without notice to the gas marketer or retailer of electricity. 2010, c. 8, s. 38 (21).

Audit, where notice provided

(4) Despite subsection (3), where the Board does provide notice of the audit to the gas marketer or retailer of electricity, it shall do so in the manner prescribed by regulation and the notice shall include the information prescribed by regulation. 2010, c. 8, s. 38 (21).

Examination of records, etc.

(5) For the purposes of subsection (1), the person appointed may do or cause to be done any one or more of the following:

1. Examining any record or copying any document or record, in any form, by any method.

2. Requiring any document or record that is required to be kept under this Act to be provided, in any form, and requiring any other document or record related to the purposes of the audit to be provided, in any form.

3. Examining documents relating to the training, education or professional credentials, certificates, accreditations or other designations of the employees, agents or third parties for the gas marketer or retailer of electricity, including determining which credentials, certificates, accreditations or other designations the employee, agent or third party has or has not received.

4. Removing from a place documents or records, in any form, that are provided under paragraph 2 for the purpose of making copies.

5. Making reasonable inquiries of any person, orally or in writing. 2010, c. 8, s. 38 (21).

Section Amendments with date in force (d/m/y)

Regulations

88.4 The Lieutenant Governor in Council may make regulations governing all matters dealt with in this Part that are required or permitted to be prescribed by regulation or that are required or permitted to be done in accordance with the regulations. 2010, c. 8, s. 38 (21).

Section Amendments with date in force (d/m/y)

PART V.2
ELECTRIC VEHICLE CHARGING

Definitions

88.5 In this Part,

"electric vehicle" means, subject to the regulations, a vehicle that has its motive power wholly or partly provided by electricity stored in a battery or other electricity storage device in the vehicle that is capable of being charged from an electricity source external to the vehicle; ("véhicule électrique")

"electric vehicle charging" means, subject to the regulations, the supply of electricity from an electric vehicle charging station to an electric vehicle in order to charge the vehicle; ("recharge des véhicules électriques")

"electric vehicle charging station" means, subject to the regulations, an electricity supply device, including any associated equipment, technologies and components, that is used to supply electricity to charge an electric vehicle. ("station de recharge pour véhicules électriques") 2024, c. 26, Sched. 3, s. 3 (2).

Section Amendments with date in force (d/m/y)

Application of Act

88.6 (1) This Act does not apply with respect to the distribution or retail of electricity for electric vehicle charging, except as may be provided by the regulations. 2024, c. 26, Sched. 3, s. 3 (2).

Interpretation

(2) For greater certainty, except as may be provided by the regulations, a reference in a provision to the distribution or retail of electricity shall not be read as including the distribution or retail described in subsection (1). 2024, c. 26, Sched. 3, s. 3 (2).

No past application

(3) This Act is deemed not to have applied with respect to the distribution or retail of electricity for electric vehicle charging before the day the *Affordable Energy Act, 2024* received Royal Assent. 2024, c. 26, Sched. 3, s. 3 (2).

Section Amendments with date in force (d/m/y)

Regulations

88.7 (1) The Lieutenant Governor in Council may make regulations,

(a) clarifying or modifying, including expanding or restricting, the definition of "electric vehicle", "electric vehicle charging" or "electric vehicle charging station" in section 88.5;

(b) clarifying the application of section 88.6;

(c) providing for and governing the application of this Act to the distribution or retail of electricity for electric vehicle charging, subject to such modifications in application as the regulations may specify. 2024, c. 26, Sched. 3, s. 3 (2).

Same

(2) A regulation made under this section may be general or particular in its application. 2024, c. 26, Sched. 3, s. 3 (2).

Section Amendments with date in force (d/m/y)

88.8 Repealed: 2003, c. 3, s. 58.

Section Amendments with date in force (d/m/y)

88.9 Repealed: 2010, c. 8, s. 38 (21).

Section Amendments with date in force (d/m/y)

88.9.1 Repealed: 2010, c. 8, s. 38 (21).

Section Amendments with date in force (d/m/y)

88.10 Repealed: 2010, c. 8, s. 38 (21).

Section Amendments with date in force (d/m/y)

88.11 Repealed: 2010, c. 8, s. 38 (21).

Section Amendments with date in force (d/m/y)

88.12 Repealed: 2010, c. 8, s. 38 (21).

Section Amendments with date in force (d/m/y)

88.13 Repealed: 2003, c. 3, s. 61.

Section Amendments with date in force (d/m/y)

88.14 Repealed: 2003, c. 3, s. 61.

Section Amendments with date in force (d/m/y)

PART VI
TRANSMISSION AND DISTRIBUTION LINES

Definitions, Part VI

89 In this Part,

"electricity distribution line" means a line, transformers, plant or equipment used for conveying electricity at voltages of 50 kilovolts or less; ("ligne de distribution d'électricité")

"electricity transmission line" means a line, transformers, plant or equipment used for conveying electricity at voltages higher than 50 kilovolts; ("ligne de transport d'électricité")

"hydrocarbon line" means a pipe line carrying any hydrocarbon, other than a pipe line within an oil refinery, oil or petroleum storage depot, chemical processing plant or pipe line terminal or station; ("ligne pour hydrocarbures")

"interconnection" means the plant, equipment and apparatus linking adjacent transmission or distribution systems as defined in Part V; ("interconnexion")

"work" means a hydrocarbon line, electricity distribution line, electricity transmission line, interconnection or station. ("ouvrage") 1998, c. 15, Sched. B, s. 89; 2003, c. 3, s. 62.

Section Amendments with date in force (d/m/y)

Leave to construct hydrocarbon line

90 (1) No person shall construct a hydrocarbon line without first obtaining from the Board an order granting leave to construct the hydrocarbon line if,

(a) the proposed hydrocarbon line is more than 20 kilometres in length;

(b) the proposed hydrocarbon line is projected to cost more than the amount prescribed by the regulations;

(c) any part of the proposed hydrocarbon line,

(i) uses pipe that has a nominal pipe size of 12 inches or more, and

(ii) has an operating pressure of 2,000 kilopascals or more; or

(d) criteria prescribed by the regulations are met. 2003, c. 3, s. 63 (1).

Exception

(2) Subsection (1) applies to the relocation or reconstruction of a hydrocarbon line only if the conditions prescribed by the regulations are met. 2024, c. 16, Sched. 11, s. 1.

---

v **Section Amendments with date in force (d/m/y)**

Application for leave to construct hydrocarbon line or station

91 (1) Any person may, before constructing a hydrocarbon line to which subsection 90 (1) does not apply or a station, apply to the Board for an order granting leave to construct the hydrocarbon line or station. 2024, c. 10, s. 6.

Applies to exempted hydrocarbon lines

(2) For greater certainty, a person who has obtained an exemption from the requirements of subsection 90 (1) may make an application under subsection (1) of this section in respect of the exempt hydrocarbon line. 2024, c. 10, s. 6.

---

v **Section Amendments with date in force (d/m/y)**

Leave to construct, etc., electricity transmission or distribution line

92 (1) No person shall construct, expand or reinforce an electricity transmission line or an electricity distribution line or make an interconnection without first obtaining from the Board an order granting leave to construct, expand or reinforce such line or interconnection. 1998, c. 15, Sched. B, s. 92 (1).

Exception

(2) Subsection (1) applies to the relocation or reconstruction of an existing electricity transmission line or electricity distribution line or interconnection where no expansion or reinforcement is involved only if the acquisition of additional land or authority to use additional land is necessary. 2024, c. 16, Sched. 11, s. 2.

---

v **Section Amendments with date in force (d/m/y)**

---

93 Repealed: 2003, c. 3, s. 65.

Section Amendments with date in force (d/m/y)

Route map

94 An applicant for an order granting leave under this Part shall file with the application a map showing the general location of the proposed work and the municipalities, highways, railways, utility lines and navigable waters through, under, over, upon or across which the proposed work is to pass. 1998, c. 15, Sched. B, s. 94.

Exemption, subs. 90 (1) or 92 (1)

95 (1) The Board may, if in its opinion special circumstances of a particular case so require, make an order exempting any person from the requirements of subsection 90 (1) or 92 (1) without a hearing. 2024, c. 10, s. 7.

Same, prescribed circumstances

(2) The Board shall, with or without a hearing, make an order exempting a person from the requirements of subsection 90 (1) or 92 (1) if the Board is satisfied that the circumstances prescribed by the regulations have been met. 2024, c. 10, s. 7.

Section Amendments with date in force (d/m/y)

Order allowing work to be carried out

96 (1) If, after considering an application under section 90, 91 or 92 the Board is of the opinion that the construction, expansion or reinforcement of the proposed work is in the public interest, it shall make an order granting leave to carry out the work. 1998, c. 15, Sched. B, s. 96.

Applications under s. 92

(2) In an application under section 92, the Board shall only consider the following when, under subsection (1), it considers whether the construction, expansion or reinforcement of the electricity transmission line or electricity distribution line, or the making of the interconnection, is in the public interest:

1. The interests of consumers with respect to prices and the reliability and quality of electricity service.

2. Repealed: 2021, c. 25, Sched. 19, s. 2.

2009, c. 12, Sched. D, s. 16; 2021, c. 25, Sched. 19, s. 2.

Section Amendments with date in force (d/m/y)

Lieutenant Governor in Council, order re electricity transmission line

96.1 (1) The Lieutenant Governor in Council may make an order declaring that the construction, expansion or reinforcement of an electricity transmission line specified in the order is needed as a priority project. 2015, c. 29, s. 16.

Effect of order

(2) When it considers an application under section 92 in respect of the construction, expansion or reinforcement of an electricity transmission line specified in an order under subsection (1), the Board shall accept that the construction, expansion or reinforcement is needed when forming its opinion under section 96. 2015, c. 29, s. 16.

Obligations must be followed

(3) Nothing in this section relieves a person from the obligation to obtain leave of the Board for the construction, expansion or reinforcement of an electricity transmission line specified in an order under subsection (1). 2015, c. 29, s. 16.

Section Amendments with date in force (d/m/y)

Directives, applications re certain natural gas lines

96.2 (1) The Minister may issue, and the Board shall implement, directives that have been approved by the Lieutenant Governor in Council providing that if the construction of a proposed natural gas transmission or dual-purpose transmission and distribution line specified by the directive is the subject of an application under section 90,

(a) the Board shall accept that it is in the public interest for such natural gas consumers as are specified in the directive to bear the full cost of the line; and

(b) the Board may not require a contribution in aid of construction or surcharge to be paid by a natural gas consumer who will be connected to or served by the line. 2024, c.

10, s. 8 (1).

Same

(2) A directive issued under subsection (1) may specify one or more proposed natural gas transmission or dual-purpose transmission and distribution lines or classes of lines. 2024, c. 10, s. 8 (1).

Ongoing applications

(3) If it so provides, a directive issued under subsection (1) applies with respect to an application made but not finally determined before the day the directive is issued. 2024, c. 10, s. 8 (1).

Directives re certain Board orders

(4) If, during the period referred to in subsection (5), the Board makes an order refusing to grant leave to construct a proposed natural gas transmission or dual-purpose transmission and distribution line or an order granting leave to construct such a line subject to a condition that a contribution in aid of construction by natural gas consumers is required, the Minister may issue, and the Board shall implement, a directive that has been approved by the Lieutenant Governor in Council,

(a) requiring the Board to rescind the order and hold a new hearing of the application, in the manner specified in the directive; and

(b) providing that clauses (1) (a) and (b) apply with respect to the new hearing. 2024, c. 10, s. 8 (1).

Note: On a day to be named by proclamation of the Lieutenant Governor, subsection 96.2 (4) is repealed. (See: 2024, c. 10, s. 8 (2))

Limitation

(5) Subsection (4) applies with respect to orders made on or after February 22, 2024 and before January 1, 2025. 2024, c. 10, s. 8 (1).

Note: On a day to be named by proclamation of the Lieutenant Governor, subsection 96.2 (5) is repealed. (See: 2024, c. 10, s. 8 (2))

Procedural fairness does not apply

(6) Neither the issuance or approval of a directive under this section nor any action taken by the Board to implement or comply with it is subject to any duty of procedural fairness, including any requirement to provide notice, reasons or an opportunity to make submissions. 2024, c. 10, s. 8 (1).

Same

(7) Subsection (6) applies despite the *Statutory Powers Procedure Act* and any other law. 2024, c. 10, s. 8 (1).

Conflict

(8) In the event of a conflict between a directive under this section and the *Statutory Powers Procedure Act*, the rules made by the Board under section 25.1 of that Act or an order of the Board or other instrument or document made or issued under this Act, the directive prevails to the extent of the conflict. 2024, c. 10, s. 8 (1).

Publication

(9) A directive issued under this section shall be published in *The Ontario Gazette*. 2024, c. 10, s. 8 (1).

Not a regulation

(10) For greater certainty, Part III (Regulations) of the *Legislation Act, 2006* does not apply to directives issued under this section. 2024, c. 10, s. 8 (1).

Section Amendments with date in force (d/m/y)

Condition, land-owner's agreements

97 In an application under section 90, 91 or 92, leave to construct shall not be granted until the applicant satisfies the Board that it has offered or will offer to each owner of land affected by the approved route or location an agreement in a form approved by the Board. 1998, c. 15, Sched. B, s. 97.

No leave if covered by licence

97.1 (1) In an application under section 92, leave shall not be granted to a person if a licence issued under Part V that is held by another person includes an obligation to develop,

construct, expand or reinforce the line, or make the interconnection, that is the subject of the application. 2016, c. 10, Sched. 2, s. 16.

Transition

(2) For greater certainty, an application made, but not determined, before the day section 16 of Schedule 2 to the *Energy Statute Law Amendment Act, 2016* comes into force, is subject to subsection (1). 2016, c. 10, Sched. 2, s. 16.

Section Amendments with date in force (d/m/y)

Leave in the procurement, selection context

97.2 (1) In an application under section 92, leave to construct, expand or reinforce an electricity transmission line or to make an interconnection shall not be granted to a person if,

(a) the IESO has commenced, been directed to commence, or announced a future procurement process for the development, construction, expansion or reinforcement of that line or for the making of that interconnection, and the procurement process has not yet been completed or otherwise terminated;

(b) the IESO has commenced, been directed to commence, or announced a future process to select a transmitter for the development, construction, expansion or reinforcement of that line or for the making of that interconnection, and the process has not yet been completed or otherwise terminated;

(c) the IESO has completed a procurement process for the development, construction, expansion or reinforcement of that line or for the making of that interconnection, and the person is someone other than the person with whom the IESO has entered into a procurement contract respecting the development, construction, expansion, reinforcement or interconnection; or

(d) the IESO has completed a process to select a transmitter for the development, construction, expansion or reinforcement of that line or for the making of that interconnection, and the person is someone other than the selected transmitter. 2016, c. 10, Sched. 2, s. 16.

No hearing required

(2) If the applicant in an application under section 92 is a person with whom the IESO has entered into a procurement contract respecting the development, construction, expansion, reinforcement of the line or the making of the interconnection, the Board may make an order under section 96 without holding a hearing. 2016, c. 10, Sched. 2, s. 16.

Procurement contract

(3) For the purposes of subsections (1) and (2),

"procurement contract" has the same meaning as in the *Electricity Act, 1998*. 2016, c. 10, Sched. 2, s. 16.

Transition

(4) For greater certainty, an application made, but not determined, before the day section 16 of Schedule 2 to the *Energy Statute Law Amendment Act, 2016* comes into force, is subject to subsections (1) and (2). 2016, c. 10, Sched. 2, s. 16.

Section Amendments with date in force (d/m/y)

Procurement contracts re transmission systems

97.3 (1) In an application under section 92, the Board shall accept as valid and not inquire into the basis of,

(a) amounts payable under a procurement contract entered into under clause 25.32 (2) (d) of the *Electricity Act, 1998*, including the prices and costs provided for by the procurement contract, and any costs associated with the procurement contract; or

(b) any procurement process relating to a procurement contract referred to in clause (a). 2019, c. 6, Sched. 1, s. 7.

Same

(2) For greater certainty, subsection (1) does not otherwise affect the making of a determination by the Board under section 96 with respect to the application. 2019, c. 6, Sched. 1, s. 7.

v **Section Amendments with date in force (d/m/y)**

Right to enter land

98 (1) The following persons may enter on land at the intended location of any part of a proposed work and may make such surveys and examinations as are necessary for fixing the site of the work:

1. Any person who has leave under this Part or a predecessor of this Part to construct the work.

2. Any person who is exempted under section 95 from the requirement to obtain leave to construct the work.

3. Where the proposed work is the expansion or reinforcement of a transmission or distribution system, any person who is required by the Board, pursuant to a condition of the person's licence, to expand or reinforce the transmission or distribution system.

4. The officers, employees and agents of a person described in paragraph 1, 2 or 3. 2006, c. 33, Sched. X, s. 2 (1).

(1.1) Repealed: 2020, c. 36, Sched. 34, s. 6 (1).

Order, hydrocarbon line

(2) The Board may, on application, issue an order authorizing a person and the officers, employees and agents of that person to enter on land at the intended location of any part of a proposed hydrocarbon line and to make such surveys and examinations as are necessary for fixing the site of the hydrocarbon line and as are specified in the order if,

(a) the person has applied for leave under section 90 and has complied with section 94; or

(b) the person has applied to the Board for an exemption from the requirements of subsection 90 (1) under section 95. 2020, c. 36, Sched. 34, s. 6 (1); 2024, c. 10, s. 9.

Order, other works

(3) Subject to subsection (4), the Board may, on application, issue an order authorizing a person and the officers, employees and agents of that person to enter on land intended for the proposed construction, expansion or reinforcement of an electricity distribution line or electricity transmission line or making of an interconnection, or for the development of any such proposed work, for any of the following purposes:

1. To gather field data and conduct tests to facilitate the preparation of an environmental assessment under the *Environmental Assessment Act* in relation to the proposed work, or to facilitate the preparation of an application for any other permit or approval required for the proposed work.

2. To determine the land required for the proposed construction, expansion, reinforcement or making of the work. 2020, c. 36, Sched. 34, s. 6 (1).

Same

(4) Subsection (3) applies if,

(a) either of the following applies with respect to the proposed work:

(i) proposed terms of reference for the preparation of an environmental assessment for the proposed work have been approved under subsection 17.4 (10) of the *Environmental Assessment Act*, or

(ii) the applicant has issued an initial notification respecting the proposed work in accordance with the requirements of the document titled "Class Environmental Assessment for Minor Transmission Facilities", as it is amended from time to time, that is published by and available from Hydro One Inc.; and

Note: On a day to be named by proclamation of the Lieutenant Governor, subclause 98 (4) (a) (ii) of the Act is repealed and the following substituted: (See: 2020, c. 36, Sched. 34, s. 6 (3))

(ii) the applicant has commenced, in accordance with the requirements of Part II.4 of the *Environmental Assessment Act*, the process for completing an environmental assessment under that Part; and

(b) any other requirements that are prescribed by the regulations have been met. 2020, c. 36, Sched. 34, s. 6 (1, 2).

Factors

(5) In an application under subsection (3), the Board shall consider,

(a) whether, before applying, the applicant made reasonable efforts to obtain consent for entry onto the land from the owner of the land; and

(b) whether entry onto the land is needed for a purpose listed in subsection (3). 2020, c. 36, Sched. 34, s. 6 (1).

Damages

(6) Any damages resulting from an entry onto land carried out under subsection (1) or under an order made under subsection (2) or (3) shall be determined by agreement or, failing agreement, in the manner set out in section 100. 2020, c. 36, Sched. 34, s. 6 (1).

Section Amendments with date in force (d/m/y)

Expropriation

99 (1) The following persons may apply to the Board for authority to expropriate land for a work:

1. Any person who has leave under this Part or a predecessor of this Part.

2. Any person who intends to construct, expand or reinforce an electricity transmission line or an electricity distribution line or make an interconnection and who is exempted under this Act from the requirement to obtain leave. 1998, c. 15, Sched. B, s. 99 (1); 2023, c. 2, Sched. 6, s. 1.

Hearing

(2) The Board shall set a date for the hearing of the application, but the date shall not be earlier than 14 days after the date of the application. 1998, c. 15, Sched. B, s. 99 (2).

Information to be filed

(3) The applicant shall file with the Board a plan and description of the land required, together with the names of all persons having an apparent interest in the land. 1998, c. 15, Sched. B, s. 99 (3).

(4) Repealed: 2003, c. 3, s. 67.

Power to make order

(5) If after the hearing the Board is of the opinion that the expropriation of the land is in the public interest, it may make an order authorizing the applicant to expropriate the land. 1998, c. 15, Sched. B, s. 99 (5).

---

v **Section Amendments with date in force (d/m/y)**

Determination of compensation

100 If compensation for damages is provided for in this Part and is not agreed on, the compensation shall be determined by the Ontario Land Tribunal under the *Expropriations Act* and, for the purpose, sections 26 and 29 of that Act apply with necessary modifications. 2021, c. 4, Sched. 6, s. 73 (2).

---

v **Section Amendments with date in force (d/m/y)**

Crossings with leave

101 (1) The following persons may apply to the Board for authority to construct a work upon, under or over a highway, utility line or ditch:

1. Any person who has leave to construct the work under this Part.

2. Any person who intends to construct the work and who is exempted under this Act from the requirement to obtain leave.

3. Where the proposed work is the expansion or reinforcement of a transmission or distribution system, any person who is required by the Board, pursuant to a condition of the person's licence, to expand or reinforce the transmission or distribution system.

4. The officers, employees and agents of a person described in paragraph 1, 2 or 3. 2006, c. 33, Sched. X, s. 3; 2023, c. 2, Sched. 6, s. 2.

Procedure

(2) The procedure set out in subsections 99 (1) to (4) applies with necessary modifications to an application under this section. 1998, c. 15, Sched. B, s. 101 (2).

Order

(3) Without any other leave and despite any other Act, if after the hearing the Board is of the opinion that the construction of the work upon, under or over a highway, utility line or ditch is in the public interest, it may make an order authorizing the construction upon such conditions as it considers appropriate. 1998, c. 15, Sched. B, s. 101 (3).

Section Amendments with date in force (d/m/y)

Right to compensation for damages

102 Any person who has acquired land for a work under this Part by agreement with the owner of the land shall pay to the owner due compensation for any damages resulting from the exercise of the person's rights under the agreement and, if the compensation is not agreed upon, it shall be determined in the manner set out in section 100. 1998, c. 15, Sched. B, s. 102.

Entry upon land

103 (1) Any person may at any time enter upon land, without the consent of the owner of the land, for the purpose of inspecting, altering, maintaining, repairing, renewing, disconnecting, replacing or removing a work or part of a work where leave for the construction, expansion or reinforcement of the work or the making of an interconnection was granted under this Part or a predecessor of this Part. 1998, c. 15, Sched. B, s. 103 (1).

Compensation

(2) Compensation for any damages resulting from the exercise of a right under subsection (1), if not agreed upon by the person and the owner of the land, shall be determined in the manner set out in section 100. 1998, c. 15, Sched. B, s. 103 (2).

Non-application, *Public Utilities Act*, s. 58

104 If leave to construct a work has been granted under this Part, section 58 of the *Public Utilities Act* does not apply to that work. 1998, c. 15, Sched. B, s. 104.

PART VI.1
ELECTRICITY INFRASTRUCTURE

Definitions

104.1 In this Part,

"development" includes the expansion or reinforcement of existing electricity infrastructure; ("aménagement")

"electricity infrastructure" means a distribution system, a transmission system and any related structure, system, equipment, facility or other thing that may be prescribed by the regulations. ("infrastructure de l'électricité") 2021, c. 2, Sched. 2, s. 7.

Section Amendments with date in force (d/m/y)

Application

104.2 This Part applies with respect to,

(a) prescribed uses of or access to electricity infrastructure that are wholly or partly for a purpose other than the generation, transmission, distribution, consumption, sale or demand management of electricity, by persons or entities prescribed by the regulations; and

(b) prescribed development of electricity infrastructure that is wholly or partly for the purpose of providing for or otherwise enabling electricity infrastructure use or access that is wholly or partly for a purpose other than the generation, transmission, distribution, consumption, sale or demand management of electricity. 2021, c. 2, Sched. 2, s. 7.

Section Amendments with date in force (d/m/y)

Regulations

104.3 (1) The Lieutenant Governor in Council may make regulations governing the development of, use of or access to electricity infrastructure for the purposes of this Part, including,

(a) for the purposes of section 104.2 and the application of this Part,

(i) specifying or otherwise determining uses of and access to electricity infrastructure that are wholly or partly for a purpose other than the generation, transmission, distribution, consumption, sale or demand management of electricity, including, for greater certainty, anticipated or otherwise prospective uses and access,

(ii) specifying or otherwise determining development of electricity infrastructure that is wholly or partly for the purpose of providing for or otherwise enabling electricity infrastructure use or access that is wholly or partly for a purpose other than the generation, transmission, distribution, consumption, sale or demand management of electricity, including, for greater certainty, in relation to anticipated or otherwise prospective uses or access, and

(iii) prescribing persons and entities;

(b) prescribing powers and duties of the Board in relation to the development of, use of and access to electricity infrastructure to which this Part applies, and governing the exercise of those powers and performance of those duties;

(c) requiring the Board to amend conditions in licences issued under Part V to a transmitter, distributor or other prescribed person respecting the development of, use of or access to electricity infrastructure to which this Part applies, and specifying and governing the conditions;

(d) governing charges or costs for the development of, use of or access to electricity infrastructure to which this Part applies and governing the amounts of the charges or costs, including fixing the amounts, setting maximum or minimum amounts or prescribing methods or techniques for determining amounts or maximum or minimum amounts;

(e) requiring a transmitter, distributor or other prescribed person licensed under Part V to make arrangements with other parties or take any other steps, including entering into contracts, in relation to charges or costs referred to in clause (d) or otherwise in relation to the development of, use of or access to electricity infrastructure to which this Part applies;

(f) specifying provisions that must be included in contracts or other arrangements entered into by a transmitter, distributor or other prescribed person licensed under Part V in relation to the development of, use of or access to electricity infrastructure to which this Part applies, whether those contracts or other arrangements are required by regulations made under clause (e) or otherwise;

(g) specifying, with respect to a matter relating to the development of, use of or access to electricity infrastructure to which this Part applies, whether the Board is to hold a hearing, the circumstances under which a hearing may or may not be held and, if a hearing is to be held, the type of hearing to be held;

(h) requiring or directing the Board to require a transmitter, distributor or other prescribed person licensed under Part V to develop any specified aspect of its electricity infrastructure to which this Part applies, in a specified time and manner;

(i) governing the preparation or implementation of capital plans respecting the development of, use of or access to electricity infrastructure to which this Part applies by a transmitter, distributor or other prescribed person licensed under Part V, including,

(i) requiring or directing the Board to require the preparation or implementation of such capital plans, and

(ii) determining or directing the Board to determine requirements that the capital plans must meet, including that they contain specified information or be prepared or implemented by a specified time or in a specified manner;

(j) governing performance standards relating to the development of, use of or access to electricity infrastructure to which this Part applies, including establishing or directing the Board to establish such performance standards;

(k) governing the provision of information or reports respecting the development of, use of or access to electricity infrastructure to which this Part applies by a licensed transmitter or distributor or any other prescribed person, including,

(i) requiring or directing the Board to require the provision of such information or reports, and

(ii) determining or directing the Board to determine the information or reports that must be provided and the time and manner of the provision;

(l) for the purposes of the payment of compensation under section 104.4,

(i) governing amounts payable to a transmitter, distributor or other prescribed person licensed under Part V under that section, including prescribing methods or techniques for calculating or determining the amounts,

(ii) requiring the IESO to receive payments made by the Minister under that section and to make payments to a transmitter, distributor or other prescribed person licensed under Part V, and

(iii) requiring a transmitter, distributor or other prescribed person licensed under Part V to receive payments referred to in subclause (ii) or to participate in prescribed methods for receiving such payments;

(m) respecting anything that, in this Part, is described as being prescribed or that may or must be done by the regulations;

(n) providing that a provision of any other Part of this Act does not apply with respect to a matter to which this Part applies, or otherwise modifying the application of a provision of any other Part of the Act that applies with respect to a matter to which this Part applies;

(o) governing transitional matters arising from the enactment or application of this Part, including in relation to contracts or agreements respecting the development of, use of or access to electricity infrastructure that exist when this Part begins to apply to the development, use or access. 2021, c. 2, Sched. 2, s. 7.

Licence conditions

(2) Regulations made under clause (1) (c) may provide for licence conditions pertaining to any matter respecting the development of, use of or access to electricity infrastructure to which this Part applies, including, for greater certainty, respecting matters prescribed under clauses (1) (d), (e), (f), (h), (i), (j), (k) and (l). 2021, c. 2, Sched. 2, s. 7.

General or particular

(3) A regulation made under subsection (1) may be general or particular in its application, and may provide for different classes of development, use, access, electricity infrastructure, transmitters, distributors, other persons or entities or any other thing. 2021, c. 2, Sched. 2, s. 7.

Retroactive

(4) A regulation made under subsection (1) is, if it so provides, effective with respect to a period before it is filed. 2021, c. 2, Sched. 2, s. 7.

Adoption by reference

(5) A regulation made under subsection (1) may adopt by reference, in whole or in part, with such changes as the Lieutenant Governor in Council considers necessary, any document, including a code, formula, standard, protocol or procedure, and may require compliance with any document so adopted. 2021, c. 2, Sched. 2, s. 7.

Publication

(6) Documents adopted in accordance with subsection (5) shall be published on the Board's website and made publicly available in any other manner the Board considers advisable. 2021, c. 2, Sched. 2, s. 7.

Conflict

(7) In the event of a conflict between a regulation made under subsection (1) and any other Part of this Act, the regulations, any other Act or regulation that is prescribed by the regulations, an order of the Board or a code issued under section 70.1, the regulation made under subsection (1) prevails to the extent of the conflict. 2021, c. 2, Sched. 2, s. 7.

Operation unaffected

(8) For greater certainty, subject to clause (1) (n) and subsection (7), an Act, regulation or other instrument that applies with respect to the development of, use of or access to

electricity infrastructure continues to apply with respect to the development of, use of and access to electricity infrastructure to which this Part applies. 2021, c. 2, Sched. 2, s. 7.

Section Amendments with date in force (d/m/y)

Compensation

104.4 (1) The Minister may make payments of such amounts as may be determined by the regulations in order to compensate a transmitter, distributor or other prescribed person licensed under Part V for any lost revenue arising from the application of this Part or the regulations. 2021, c. 2, Sched. 2, s. 7.

Same

(2) Compensation provided for under subsection (1) shall be paid for out of the money appropriated by the Legislature for the purposes of that subsection. 2021, c. 2, Sched. 2, s. 7.

Section Amendments with date in force (d/m/y)

Board objectives, electricity infrastructure

104.5 The Board, in exercising powers and performing duties for the purposes of this Part, shall be guided by the following objectives, in addition to the other Board objectives set out in this Act:

1. To facilitate the efficient development of, use of and access to electricity infrastructure to which this Part applies.

2. Any other objective that may be prescribed by the regulations in relation to the development of, use of and access to electricity infrastructure to which this Part applies or any specified class of such development, use or access. 2021, c. 2, Sched. 2, s. 7.

Section Amendments with date in force (d/m/y)

PART VII
INSPECTORS AND INSPECTIONS

Board receives complaints and makes inquiries

105 The Board may,

(a) receive complaints concerning conduct that may be in contravention of an enforceable provision whether the conduct constitutes an offence or not; and

(b) make inquiries, gather information and attempt to mediate or resolve complaints, as appropriate, concerning any matter that comes to its attention that may be in contravention of an enforceable provision whether the matter constitutes an offence or not. 2010, c. 8, s. 38 (22).

Section Amendments with date in force (d/m/y)

Inspectors

106 (1) The chief executive officer may appoint persons to exercise and perform the powers and duties of an inspector under this Part. 2003, c. 3, s. 69; 2019, c. 6, Sched. 2, s. 22 (1).

Certificate of appointment

(2) The Board shall issue to every inspector a certificate of appointment bearing the signature of the chief executive officer or a facsimile of his or her signature. 2010, c. 8, s. 38 (23); 2019, c. 6, Sched. 2, s. 22 (2).

Section Amendments with date in force (d/m/y)

Power to require documents, etc.

107 (1) An inspector may, for the purposes of this Act and any other Act that gives powers or duties to the Board, require any of the following persons to provide documents, records or information:

1. A person required to have a licence under section 48 or 57.

1.1 An affiliate, agent or employee of a gas marketer or retailer of electricity.

2. A gas distributor, gas transmitter or gas storage company or an affiliate of a gas transmitter, gas distributor or gas storage company.

3. An affiliate of a person required to have a licence under clause 57 (a) or (b).

4. A person exempted from the requirements of clause 57 (a) by regulation.

5. A person exempted from the requirements of clause 57 (b) by regulation.

6. A person exempted from the requirements of section 48 by regulation.

7. An affiliate, agent or employee of a person referred to in paragraph 4.

8. A person who is subject to an exemption under section 57.1.

9. An affiliate, agent or employee of a person referred to in paragraph 8. 2003, c. 3, s. 70; 2010, c. 8, s. 38 (24); 2023, c. 9, Sched. 24, s. 7.

Application of subs. (1)

(2) Subsection (1) only applies to documents, records and information that relate to the following:

1. Activities for which a licence is required under section 48 or 57.

1.1 The persons who are required to have a licence under section 48 or 57 and their affiliates, agents and employees.

1.2 Activities for which a licence is required under subsection 88.2 (1).

1.3 The persons who are required to have a licence under subsection 88.2 (1).

2. Gas distribution, gas transmission or gas storage, including the sale of gas by a gas distributor.

3. Transactions between a gas distributor, gas transmitter or gas storage company and its affiliates.

4. Transactions between a person required to have a licence under clause 57 (a) or (b) and its affiliates.

5. Adjustments, payments, set-offs and credits under section 25.33 of the *Electricity Act, 1998* and under the regulations made under clause 114 (1.3) (f) of that Act.

6. Payments under sections 78.1, 78.2 and 78.5. 2004, c. 23, Sched. B, s. 32; 2009, c. 12, Sched. D, s. 17; 2010, c. 8, s. 38 (25); 2014, c. 7, Sched. 23, s. 14.

Section Amendments with date in force (d/m/y)

Inspections

108 (1) An inspector may, for the purposes of this Act and any other Act that gives powers or duties to the Board, without a warrant or court order, at any reasonable time and with any reasonable assistance, conduct inspections and, for that purpose, the inspector may,

(a) enter any place that the inspector reasonably believes is likely to contain documents or records related to any of the activities referred to in subsection 107 (2); or

(b) enter any place where anything is being done that requires an order of the Board granting leave under Part VI. 2003, c. 3, s. 71 (1).

Same

(2) During an inspection under subsection (1), an inspector may,

(a) examine, record or copy any document or record, in any form, by any method;

(b) require any document or record that is required to be kept under this Act to be provided, in any form, and require any other document or record related to the purposes of the inspection to be provided, in any form;

(c) remove from a place documents or records, in any form, that are provided under clause (b) for the purpose of making copies;

(d) examine anything that is being done that requires an order of the Board granting leave under Part VI;

(e) make reasonable inquiries of any person, orally or in writing. 2003, c. 3, s. 71 (2).

Identification

(3) In conducting an inspection under this section, the inspector shall, upon request, produce his or her certificate of appointment. 2010, c. 8, s. 38 (26).

Duty to assist

(4) In exercising powers under this section, the inspector may require a person described in subsection 107 (1) or its officers, directors or employees to give all reasonable assistance to the inspector. 2003, c. 3, s. 71 (4).

Copying

(5) The inspector may, on giving a receipt, remove any document or record described in subsection (2) for the purpose of making copies or extracts and shall promptly return the document or record and obtain a written acknowledgment of its return. 2003, c. 3, s. 71 (4).

Documents in electronic form

(6) If a document or record is kept in electronic form, the inspector may make a copy of it or require that a copy of it be provided to him or her on paper or in a machine-readable medium or both. 1998, c. 15, Sched. B, s. 108 (6); 2003, c. 3, s. 71 (5); 2010, c. 8, s. 38 (27).

Evidence

(7) Copies or extracts from documents or records removed under this section and certified as being true copies or extracts from the originals by the person who made them are admissible in evidence to the same extent as and have the same evidentiary value as the originals. 1998, c. 15, Sched. B, s. 108 (7).

Dwellings

(8) This section does not authorize a person to enter a room or place actually used as a dwelling without the consent of the occupier except under the authority of a warrant issued under subsection (9). 1998, c. 15, Sched. B, s. 108 (8).

Warrant

(9) A justice of the peace may issue a warrant authorizing a person named in the warrant to enter a place identified in the warrant and exercise the powers given under this section if the justice of the peace is satisfied by information on oath that,

(a) there is reasonable ground to believe that,

(i) there are documents or records located in the place that are relevant to the carrying out of an inspection, or

(ii) anything is being done in the place that requires an order of the Board granting leave under Part VI; and

(b) entry to the place has been or will be denied. 2003, c. 3, s. 71 (6).

Same

(10) A warrant issued under this section shall,

(a) specify the hours and days during which it may be executed; and

(b) name a date on which it expires, which date shall not be later than 15 days after its issue. 1998, c. 15, Sched. B, s. 108 (10).

Extension

(11) Upon application without notice by the person named in a warrant, a justice of the peace may, before or after the warrant expires, extend the date on which the warrant expires for an additional period of not more than 15 days. 1998, c. 15, Sched. B, s. 108 (11).

Section Amendments with date in force (d/m/y)

Notifying Board

109 An inspector shall notify the Board of all matters he or she thinks relevant to Board proceedings or possible future Board proceedings. 1998, c. 15, Sched. B, s. 109; 2003, c. 3, s. 72.

Section Amendments with date in force (d/m/y)

Evidence, Board proceedings

Witnesses

110 (1) An inspector may be called as a witness by the Board in any Board proceeding. 1998, c. 15, Sched. B, s. 110 (1); 2003, c. 3, s. 73 (1).

No privilege

(2) No document, record or copy thereof obtained by an inspector under section 107 or 108, and no information obtained by an inspector under section 107, shall be excluded as evidence on the ground of privilege in any Board proceeding. 2003, c. 3, s. 73 (2).

Notice

(3) No document, record or copy thereof obtained by an inspector under section 107 or 108, and no information obtained by an inspector under section 107, that is not otherwise public, including being made public by reason of publication under section 111.1, shall be introduced in evidence in a Board proceeding unless,

(a) the Board gives the owner of the document or record or the person who provided the information notice that the inspector intends to introduce the evidence; and

(b) the Board gives the owner of the document or record or the person who provided the information an opportunity to make representations with respect to the intended introduction of that evidence. 2003, c. 3, s. 73 (3); 2017, c. 2, Sched. 10, s. 2 (9).

(4) Repealed: 2003, c. 3, s. 73 (3).

Section Amendments with date in force (d/m/y)

Confidentiality

111 (1) All documents and records obtained by an inspector under section 107 or 108, and information obtained by an inspector under section 107, are confidential and shall not be disclosed to any person other than a member of the Board or an employee of the Board except,

(a) as may be required in connection with the administration of this Act or any other Act that gives powers or duties to the Board or in any proceeding under this or any other

Act that gives powers or duties to the Board;

(b) to counsel for the Board or an employee of the Board;

(c) with the consent of the owner of the document or record or the person who provided the information; or

(d) in accordance with an agreement described in subsection (3). 2003, c. 3, s. 74; 2015, c. 29, s. 17 (1).

Same

(2) If any document, record or information obtained by an inspector under section 107 or 108 that is not otherwise public, including being made public by reason of publication under section 111.1, is admitted in evidence in a proceeding under this Act or any other Act that gives powers or duties to the Board, the Board may rule on whether the document, record or information is to be kept confidential. 2017, c. 2, Sched. 10, s. 2 (10).

Agreements re information-sharing

(3) The Board may enter into an agreement with the Electrical Safety Authority providing for the sharing of documents, records and information that are described in subsection (1) and are relevant to the objects of the Electrical Safety Authority. 2015, c. 29, s. 17 (2).

Section Amendments with date in force (d/m/y)

Publication of inspection reports

111.1 (1) Despite section 111 but subject to subsection (2), the Board may publish a document, record or information obtained by an inspector under section 107 or 108 as part of a report that describes an inspection conducted under this Part and the results or findings of the inspection. 2017, c. 2, Sched. 10, s. 2 (11).

Non-publication of confidential material

(2) The Board shall not publish a document, record or information under subsection (1) that is not otherwise public unless the Board gives the owner of the document or record or the person who provided the document, record or information an opportunity to make representations with respect to the intended publication. 2017, c. 2, Sched. 10, s. 2 (11).

Section Amendments with date in force (d/m/y)

Evidence

112 No document, record or information obtained by an inspector under this Part that is not otherwise public, including being made public by reason of publication under section 111.1, is admissible in evidence in any proceeding except a proceeding in respect of an order of the Board or a proceeding in respect of an offence under section 126. 2017, c. 2, Sched. 10, s. 2 (12).

Section Amendments with date in force (d/m/y)

PART VII.0.1
INVESTIGATORS AND INVESTIGATIONS

Investigators

112.0.1 (1) The chief executive officer may appoint persons to exercise and perform the powers and duties of an investigator under this Part and Part IX. 2010, c. 8, s. 38 (28); 2019, c. 6, Sched. 2, s. 23 (1).

Certificate of appointment

(2) The chief executive officer shall issue to every investigator a certificate of appointment bearing the chief executive officer's signature or a facsimile of his or her signature. 2019, c. 6, Sched. 2, s. 23 (2).

Production of certificate of appointment

(3) Every investigator who is conducting an investigation shall, upon request, produce his or her certificate of appointment. 2010, c. 8, s. 38 (28).

Section Amendments with date in force (d/m/y)

Search warrant

112.0.2 (1) Upon application made without notice by an investigator, a justice of the peace may issue a warrant if he or she is satisfied on information under oath that there is reasonable ground for believing that,

(a) a person has contravened or is contravening an enforceable provision; and

(b) there is,

(i) in any building, dwelling, receptacle or place anything relating to the contravention of an enforceable provision, or

(ii) information or evidence relating to the contravention of an enforceable provision that may be obtained through the use of an investigative technique or procedure or the doing of anything described in the warrant. 2010, c. 8, s. 38 (28).

Powers under warrant

(2) Subject to any conditions contained in it, a warrant obtained under subsection (1) authorizes an investigator,

(a) to enter or access the building, dwelling, receptacle or place specified in the warrant and examine and seize anything described in the warrant;

(b) to use any data storage, processing or retrieval device or system used in carrying on business in order to produce information or evidence described in the warrant, in any form;

(c) to exercise any of the powers specified in subsection (10); and

(d) to use any investigative technique or procedure or do anything described in the warrant. 2010, c. 8, s. 38 (28).

Entry of dwelling

(3) Despite subsection (2), an investigator shall not exercise the power under a warrant to enter a place, or part of a place, used as a dwelling, unless,

(a) the justice of the peace is informed that the warrant is being sought to authorize entry into a dwelling; and

(b) the justice of the peace authorizes the entry into the dwelling. 2010, c. 8, s. 38 (28).

Conditions on a warrant

(4) A warrant obtained under subsection (1) shall contain such conditions as the justice of the peace considers advisable to ensure that any search authorized by the warrant is reasonable in the circumstances. 2010, c. 8, s. 38 (28).

Expert help

(5) The warrant may authorize persons who have special, expert or professional knowledge and other persons as necessary to accompany and assist the investigator in respect of the execution of the warrant. 2010, c. 8, s. 38 (28).

Time of execution

(6) An entry or access under a warrant issued under this section shall be made between 6 a.m. and 9 p.m., unless the warrant specifies otherwise. 2010, c. 8, s. 38 (28).

Expiry of warrant

(7) A warrant issued under this section shall name a date of expiry, which shall be no later than 30 days after the warrant is issued, but a justice of the peace may extend the date of expiry for an additional period of no more than 30 days, upon application without notice by an investigator. 2010, c. 8, s. 38 (28).

Use of force

(8) An investigator may call upon police officers for assistance in executing the warrant and the investigator may use whatever force is reasonably necessary to execute the warrant. 2010, c. 8, s. 38 (28).

Obstruction

(9) No person shall obstruct an investigator executing a warrant under this section or withhold from him or her or conceal, alter or destroy anything relevant to the investigation being conducted pursuant to the warrant. 2010, c. 8, s. 38 (28).

Assistance

(10) An investigator may, in the course of executing a warrant, require a person to produce the evidence or information described in the warrant and to provide whatever assistance is reasonably necessary, including using any data storage, processing or retrieval device or system to produce, in any form, the evidence or information described in the warrant and the person shall produce the evidence or information or provide the assistance. 2010, c. 8, s. 38 (28).

Return of seized items

(11) An investigator who seizes any thing under this section or under section 112.0.3 may make a copy of it and shall return it within a reasonable time. 2010, c. 8, s. 38 (28).

Admissibility

(12) A copy of a document or record certified by an investigator as being a true copy of the original is admissible in evidence to the same extent as the original and has the same evidentiary value. 2010, c. 8, s. 38 (28).

---

v **Section Amendments with date in force (d/m/y)**

Seizure of thing not specified

112.0.3 An investigator who is lawfully present in a place pursuant to a warrant or otherwise in the execution of his or her duties may, without a warrant, seize anything in plain view that the investigator believes on reasonable grounds will afford evidence relating to a contravention of an enforceable provision. 2010, c. 8, s. 38 (28).

---

v **Section Amendments with date in force (d/m/y)**

Searches in exigent circumstances

112.0.4 (1) An investigator may exercise any of the powers described in subsection 112.0.2 (2) without a warrant if the conditions for obtaining the warrant exist but by reason of exigent circumstances it would be impracticable to obtain the warrant. 2010, c. 8, s. 38 (28).

Dwelling

(2) Subsection (1) does not apply to a place or part of a place that is being used as a dwelling. 2010, c. 8, s. 38 (28).

Use of force

(3) The investigator may, in executing any authority given by this section, call upon police officers for assistance and use whatever force is reasonably necessary. 2010, c. 8, s. 38 (28).

Application of s. 112.0.2

(4) Subsections 112.0.2 (5), (9), (10), (11) and (12) apply with necessary modifications to a search under this section. 2010, c. 8, s. 38 (28).

v **Section Amendments with date in force (d/m/y)**

Witnesses

112.0.5 (1) An investigator may be called as a witness by the Board in any Board proceeding. 2010, c. 8, s. 38 (28).

Notice

(2) No document, record or copy of one obtained by an investigator under a warrant obtained under section 112.0.2 or obtained without a warrant under the circumstances referred to in section 112.0.4 and no information obtained by an investigator under such a warrant or under the circumstances referred to in section 112.0.4 shall be introduced in evidence in a Board proceeding unless,

(a) the Board gives the owner of the document or record or the person who provided the information notice that the investigator intends to introduce the evidence; and

(b) the Board gives the owner of the document or record or the person who provided the information an opportunity to make representations with respect to the intended introduction of that evidence. 2010, c. 8, s. 38 (28).

Same

(3) No thing seized under section 112.0.3 and no information obtained by an investigator under such a seizure shall be introduced in evidence in a Board proceeding unless,

(a) the Board gives the owner of the thing or the person who provided the thing notice that the investigator intends to introduce the evidence; and

(b) the Board gives the owner of the thing or the person who provided the thing an opportunity to make representations with respect to the intended introduction of that evidence. 2010, c. 8, s. 38 (28).

v **Section Amendments with date in force (d/m/y)**

Confidentiality

112.0.6 (1) All documents and records obtained by an investigator under this Part or Part IX are confidential and shall not be disclosed to any person other than a member of the Board or an employee of the Board except,

(a) as may be required in connection with the administration of this Act or any other Act that gives powers or duties to the Board or in any proceeding under this or any other Act that gives powers or duties to the Board;

(b) to counsel for the Board or an employee of the Board; or

(c) with the consent of the owner of the document or record or the person who provided the information. 2010, c. 8, s. 38 (28).

Same

(2) If any document, record or information obtained by an investigator under this Part or Part IX is admitted in evidence in a proceeding under this Act or any other Act that gives powers or duties to the Board, the Board may rule on whether the document, record or information is to be kept confidential. 2010, c. 8, s. 38 (28).

Section Amendments with date in force (d/m/y)

PART VII.1
COMPLIANCE

112.1 Repealed: 2010, c. 8, s. 38 (29).

Section Amendments with date in force (d/m/y)

Procedure for orders under ss. 112.3 to 112.5

112.2 (1) An order under section 112.3, 112.4 or 112.5 may only be made on the Board's own motion. 2003, c. 3, s. 76.

Notice

(2) The Board shall give written notice to a person that it intends to make an order under section 112.3, 112.4 or 112.5. 2003, c. 3, s. 76.

Contents of notice

(3) Notice under subsection (2) shall set out the reasons for the proposed order and shall advise the person that, within 15 days after receiving the notice, the person may give notice requiring the Board to hold a hearing. 2003, c. 3, s. 76.

Service of notice or order

(3.1) Any notice or order required to be given or served by the Board under this Part or Part VII.2 is sufficiently given or served if,

(a) delivered personally;

(b) sent by registered mail; or

(c) sent by another manner, if the Board can prove receipt of the notice or order. 2010, c. 8, s. 38 (30).

Deemed service

(3.2) Where service is made by registered mail, the service is deemed to be made on the third day after the day of mailing unless the person on whom service is being made establishes that the person did not, acting in good faith, through absence, accident, illness or other cause beyond the person's control, receive the notice or order until a later date. 2010, c. 8, s. 38 (30).

Exception

(3.3) Despite subsection (3.1), the Board may order any other method of service. 2010, c. 8, s. 38 (30).

Hearing

(4) A person to whom notice is given under subsection (2) may, within 15 days after receiving the notice, give notice to the Board requiring the Board to hold a hearing. 2003, c. 3, s. 76.

If hearing not required

(5) If no notice requiring a hearing is given within the time permitted by subsection (4), the Board may make an order. 2003, c. 3, s. 76.

Interim orders under s. 112.3

(6) An interim order of the Board may be made under section 112.3, with or without a hearing, and may take effect before the time for giving notice under subsection (4) has expired. 2003, c. 3, s. 76.

---

v **Section Amendments with date in force (d/m/y)**

Action required to comply, etc.

112.3 (1) If the Board is satisfied that a person has contravened or is likely to contravene an enforceable provision, the Board may make an order requiring the person to comply with the enforceable provision and to take such action as the Board may specify to,

(a) remedy a contravention that has occurred; or

(b) prevent a contravention or further contravention of the enforceable provision. 2003, c. 3, s. 76.

Application

(2) This section applies to contraventions that occur before or after this section comes into force. 2003, c. 3, s. 76.

---

v **Section Amendments with date in force (d/m/y)**

Suspension or revocation of licences

112.4 (1) If the Board is satisfied that a person who holds a licence under Part IV or V has contravened an enforceable provision, the Board may make an order suspending or revoking the licence. 2003, c. 3, s. 76.

Application

(2) This section applies to contraventions that occur before or after this section comes into force. 2003, c. 3, s. 76.

---

v **Section Amendments with date in force (d/m/y)**

Administrative penalties

112.5 (1) If the Board is satisfied that a person has contravened an enforceable provision, the Board may, subject to the regulations under subsection (5), make an order requiring a person to pay an administrative penalty in the amount set out in the order for each day or part of a day on which the contravention occurred or continues. 2003, c. 3, s. 76.

Purpose

(1.1) The purpose of an administrative penalty is to promote compliance with the requirements established by this Act and the regulations. 2010, c. 8, s. 38 (31).

Limitation

(2) The Board shall not make an order under subsection (1) in respect of a contravention later than two years after the later of,

(a) the day the contravention occurred; and

(b) the day on which the evidence of the contravention first came to the attention of the Board. 2003, c. 3, s. 76.

Amount of penalty, limited

(3) An administrative penalty in respect of a contravention shall not exceed $1,000,000 for each day or part of a day on which the contravention occurs or continues. 2003, c. 3, s. 76; 2015, c. 29, s. 18 (1).

Limits on administrative penalty

(3.1) Despite the maximum administrative penalty set out in subsection (3), but subject to subsection (3.2), the amount of an administrative penalty set by the Board pursuant to subsection (3) may not exceed the maximum fine applicable to the person under section 126 for the contravention had a proceeding been commenced under that section. 2015, c. 29, s. 18 (2).

Increasing administrative penalty by amount of monetary benefit

(3.2) Despite anything else in this section, the Board may increase the administrative penalty that the person is required to pay by an amount equal to the monetary benefit that was acquired by, or that accrued to, the person as result of the contravention. 2015, c. 29, s. 18 (2).

No offence to be charged if penalty is paid

(4) If a person who is required by an order under subsection (1) to pay an administrative penalty in respect of a contravention pays the amount of the penalty in accordance with the order, the person shall not be charged with an offence in respect of the contravention. 2003, c. 3, s. 76.

Regulations

(5) The Lieutenant Governor in Council may make regulations,

(a) specifying types of contraventions in respect of which an order may not be made under this section and circumstances when the Board shall not make an order under this section;

(b) governing the determination of the amounts of administrative penalties, including the criteria to be considered and including providing for different amounts depending on when an administrative penalty is paid;

(c) respecting any other matter necessary for the administration of the system of administrative penalties provided for by this section. 2003, c. 3, s. 76.

General or particular

(6) A regulation under subsection (5) may be general or particular in its application. 2003, c. 3, s. 76.

Application

(7) Subject to subsection (8), this section applies to contraventions that occur before or after this section comes into force. 2003, c. 3, s. 76.

Same

(8) This section does not apply to a contravention that occurred before this section came into force unless, at the time it occurred, section 125.2 was in force and a notice could have been issued in respect of the contravention under that section. 2003, c. 3, s. 76.

Section Amendments with date in force (d/m/y)

Restraining orders

112.6 The Board may apply to the Superior Court of Justice for an order directing a person not to contravene an enforceable provision, and the court may make that order or such other order as the court considers just. 2003, c. 3, s. 76.

Section Amendments with date in force (d/m/y)

Voluntary compliance

112.7 (1) A person may give the Board a written assurance of voluntary compliance,

(a) to refrain from contravening an enforceable provision specified in the assurance;

(b) to take such action as is specified in the assurance to remedy a contravention of an enforceable provision; or

(c) to take such action as is specified in the assurance to prevent a contravention of an enforceable provision. 2003, c. 3, s. 76.

Force and effect

(2) An assurance of voluntary compliance has the same force and effect as an order of the Board. 2003, c. 3, s. 76.

(3) Repealed: 2010, c. 8, s. 38 (32).

Section Amendments with date in force (d/m/y)

Public record

112.8 (1) The Board shall maintain a public record of,

(a) assurances of voluntary compliance given under this Act;

(b) compliance orders issued under this Act;

(c) orders made under section 112.10;

(d) any other prescribed document or information. 2010, c. 8, s. 38 (33).

Orders

(2) The Board may by order require the payment of fees for the inspection of public records maintained under subsection (1) and may approve the amount of those fees. 2010, c. 8, s. 38 (33).

Same

(3) Part III (Regulations) of the *Legislation Act, 2006* does not apply to an order made under subsection (2). 2010, c. 8, s. 38 (33).

Form and manner of public record

(4) The public record maintained under subsection (1) shall be maintained by the Board in such form or manner as may be prescribed by regulation. 2010, c. 8, s. 38 (33).

Section Amendments with date in force (d/m/y)

PART VII.2
COMPLIANCE RE PART II OF THE ENERGY CONSUMER PROTECTION ACT, 2010

Application

112.9 (1) This Part applies in respect of enforceable provisions referred to in clause (b) of the definition of "enforceable provision" in section 3. 2010, c. 8, s. 38 (34).

Same

(2) This Part applies in addition to Part VII.1. 2010, c. 8, s. 38 (34).

Definitions

(3) For the purposes of this Part,

"consumer" has the same meaning as in Part II of the *Energy Consumer Protection Act, 2010*; ("consommateur")

"supplier" has the same meaning as in Part II of the *Energy Consumer Protection Act, 2010.* ("fournisseur") 2010, c. 8, s. 38 (34).

Section Amendments with date in force (d/m/y)

Freeze order

112.10 (1) If the conditions in subsection (2) are met, the Board may make an application to the Superior Court of Justice for,

(a) an order requiring any person having on deposit or controlling any assets or trust funds of a supplier or former supplier to hold those funds or assets;

(b) an order requiring a supplier or former supplier to refrain from withdrawing any asset or trust fund from a person having them on deposit or controlling them; or

(c) an order requiring a supplier or former supplier to hold any asset or trust fund of an energy consumer or other person in trust for the person entitled to it. 2010, c. 8, s. 38 (34).

Conditions

(2) The Board may make an application under subsection (1) if it believes that it is advisable for the protection of consumers and,

(a) a search warrant has been issued under this Act;

(b) an order has been made under section 112.3 or 112.11; or

(c) there has been an assurance of voluntary compliance under section 112.7 or 112.12. 2010, c. 8, s. 38 (34).

Person engaged in unfair practice

(3) Subsections (1) and (2) apply with necessary modifications to any person, whether or not the person is or was a supplier, if the person has engaged or is engaging in unfair practices under the *Energy Consumer Protection Act, 2010*. 2010, c. 8, s. 38 (34).

Limitation

(4) In the case of a bank or authorized foreign bank within the meaning of section 2 of the *Bank Act* (Canada), a credit union within the meaning of the *Credit Unions and Caisses Populaires Act, 2020* or a loan or trust corporation, the order under subsection (1) applies

only to the offices and branches named in the order. 2010, c. 8, s. 38 (34); 2020, c. 36, Sched. 7, s. 329.

Release of assets

(5) The court may consent to the release of any particular asset or trust fund from the order or may wholly revoke the order. 2010, c. 8, s. 38 (34).

Exception

(6) Subsection (1) does not apply if, prior to the Board obtaining an order under that subsection, the person files with the Board, in such manner and amount as the Board determines,

(a) a personal bond accompanied by collateral security;

(b) a bond of an insurer licensed under the *Insurance Act* to write surety and fidelity insurance;

(c) a bond of a guarantor accompanied by collateral security; or

(d) another form of security prescribed by regulation. 2010, c. 8, s. 38 (34).

Application to court

(7) An application may be made to the Superior Court of Justice for a determination in respect of the disposition of an asset or trust fund,

(a) by a person in receipt of an order under subsection (1), if that person is in doubt as to whether the order applies to the asset or trust fund; or

(b) by a person who claims an interest in the asset or trust fund subject to the order. 2010, c. 8, s. 38 (34).

Notice

(8) If an order is made under this section, the Board may register in the appropriate land registry office a notice that an order under subsection (1) has been issued and that the order may affect land belonging to the person referred to in the notice and the notice has the same effect as the registration of a certificate of pending litigation except that the Board may in writing revoke or modify the notice. 2010, c. 8, s. 38 (34).

Cancellation or discharge application

(9) A person in respect of whom an order has been made under subsection (1) or any person having an interest in land in respect of which a notice is registered under subsection (8) may apply to the Superior Court of Justice for cancellation in whole or in part of the order or for discharge in whole or in part of the registration. 2010, c. 8, s. 38 (34).

Disposition by court

(10) The Superior Court of Justice shall dispose of the application after a hearing and may cancel the order or discharge the registration in whole or in part, if the court finds,

(a) that the order or registration is not required in whole or in part for the protection of consumers or of other persons having an interest in the land; or

(b) that the interests of other persons are unduly prejudiced by the order or registration. 2010, c. 8, s. 38 (34).

Court application

(11) If the court has made an order under subsection (1) or the Board has registered a notice under subsection (8), the Board may apply to the court for directions or an order relating to the disposition of assets, trust funds or land affected by the order or notice. 2010, c. 8, s. 38 (34).

Notice not required

(12) An application by the Board under this section may be made without notice to any other person. 2010, c. 8, s. 38 (34).

Section Amendments with date in force (d/m/y)

Order for immediate compliance

112.11 (1) Without limiting the generality of section 112.3, the Board may make an order requiring immediate compliance with an enforceable provision and, subject to subsection (2), such an order takes effect immediately. 2010, c. 8, s. 38 (34).

Notice of order

(2) If the Board makes an order for immediate compliance, it shall serve on the person named in the order a notice that includes,

(a) the order;

(b) the written reasons for making the order; and

(c) a statement that the person is entitled to a hearing by the Board if the person mails or delivers to the Board, within 15 days after the notice is served, notice in writing requiring a hearing. 2010, c. 8, s. 38 (34).

Hearing

(3) When a person named in the order requires a hearing in accordance with the notice under subsection (2), the Board shall hold the hearing and may confirm or set aside the order or make such other order as the Board considers proper to give effect to the purposes of Part II of the *Energy Consumer Protection Act, 2010*. 2010, c. 8, s. 38 (34).

Expiration of order

(4) If a hearing by the Board is required,

(a) the order expires 15 days after the written request for a hearing is received by the Board; or

(b) the Board may extend the time of expiration until the hearing is concluded, if a hearing is commenced within the 15-day period referred to in clause (a). 2010, c. 8, s. 38 (34).

Same

(5) Despite subsection (4), if it is satisfied that the conduct of the person named in the order has delayed the commencement of the hearing, the Board may extend the time of the expiration for the order,

(a) until the hearing commences; and

(b) once the hearing commences, until the hearing is concluded. 2010, c. 8, s. 38 (34).

Parties

(6) The person who has required the hearing and such other persons as the Board may specify are parties to proceedings before the Board under this section. 2010, c. 8, s. 38 (34).

Section Amendments with date in force (d/m/y)

Voluntary compliance

112.12 (1) Without limiting the generality of section 112.7, a person may give the Board a written assurance of voluntary compliance,

(a) to publicize the assurance or the actions being undertaken as a result of the assurance;

(b) to pay any cost incurred in investigating the person's activities, any legal costs incurred in relation to the person's activities and any cost associated with the assurances;

(c) to take any such action as the Board considers appropriate in the circumstances. 2010, c. 8, s. 38 (34).

Security for any assurance of voluntary compliance

(2) The Board may require any person who is giving an assurance of voluntary compliance to provide, in such manner and amount as the Board determines, security in the form of,

(a) a personal bond accompanied by collateral security;

(b) a bond of an insurer licensed under the *Insurance Act* to write surety and fidelity insurance;

(c) a bond of a guarantor accompanied by collateral security; or

(d) another form of security prescribed by regulation. 2010, c. 8, s. 38 (34).

Release of security

(3) The bond and any collateral security required under subsection (2) shall not be released until the Board is satisfied that the person has fulfilled the assurance. 2010, c. 8, s. 38 (34).

Section Amendments with date in force (d/m/y)

113 REPEALED. See: Table of Public Statute Provisions Repealed Under Section 10.1 of the *Legislation Act, 2006* – December 31, 2011.

Section Amendments with date in force (d/m/y)

114 REPEALED. See: Table of Public Statute Provisions Repealed Under Section 10.1 of the *Legislation Act, 2006* – December 31, 2011.

Section Amendments with date in force (d/m/y)

115 REPEALED. See: Table of Public Statute Provisions Repealed Under Section 10.1 of the *Legislation Act, 2006* – December 31, 2011.

Section Amendments with date in force (d/m/y)

116 REPEALED. See: Table of Public Statute Provisions Repealed Under Section 10.1 of the *Legislation Act, 2006* – December 31, 2011.

Section Amendments with date in force (d/m/y)

117 REPEALED. See: Table of Public Statute Provisions Repealed Under Section 10.1 of the *Legislation Act, 2006* – December 31, 2011.

Section Amendments with date in force (d/m/y)

118 REPEALED. See: Table of Public Statute Provisions Repealed Under Section 10.1 of the *Legislation Act, 2006* – December 31, 2011.

Section Amendments with date in force (d/m/y)

119 REPEALED. See: Table of Public Statute Provisions Repealed Under Section 10.1 of the *Legislation Act, 2006* – December 31, 2011.

Section Amendments with date in force (d/m/y)

120 REPEALED. See: Table of Public Statute Provisions Repealed Under Section 10.1 of the *Legislation Act, 2006* – December 31, 2011.

Section Amendments with date in force (d/m/y)

PART IX
MISCELLANEOUS

Rules
121 The board of directors may make rules,

(a) governing the practices of employees to whom powers and duties are delegated under section 6;

(b) governing the making of rules under section 44 and the issuance of codes under section 70.1. 2003, c. 3, s. 77; 2019, c. 6, Sched. 2, s. 28 (1).

Section Amendments with date in force (d/m/y)

Provincial offences officers
122 Despite subsection 1 (3) of the *Provincial Offences Act*, the board of directors may, for the purposes of that Act, designate in writing any person or class of persons as a provincial offences officer, but the designation only applies in respect of offences under this Act. 2010, c. 8, s. 38 (35); 2019, c. 6, Sched. 2, s. 28 (1).

Section Amendments with date in force (d/m/y)

123 Repealed: 2003, c. 3, s. 79.

Section Amendments with date in force (d/m/y)

124 Repealed: 2003, c. 3, s. 80.

Section Amendments with date in force (d/m/y)

Obstruction
125 No person shall obstruct an inspector appointed under section 106 or a provincial offences officer designated under section 122 or an investigator appointed under

subsection 112.0.1 (1) or knowingly withhold or conceal from that person or destroy any relevant document, record or information required to be provided by that person. 2003, c. 3, s. 81; 2010, c. 8, s. 38 (36).

Section Amendments with date in force (d/m/y)

Method of giving notice

125.1 Subsections 18 (2) to (5) and clause 24 (1) (a) of the *Statutory Powers Procedure Act* apply, with necessary modifications, to all notices given by the Board, whether or not a hearing is held. 2003, c. 3, s. 82.

Section Amendments with date in force (d/m/y)

Duties of directors and officers of a corporation

125.2 Where a transmitter, distributor, retailer of electricity, gas marketer or unit sub-meter provider is a corporation, every director and officer of the corporation shall,

(a) exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances; and

(b) take such measures as necessary to ensure that the corporation complies with all applicable requirements under this Act, the *Electricity Act, 1998* and the *Energy Consumer Protection Act, 2010*. 2015, c. 29, s. 19.

Section Amendments with date in force (d/m/y)

Offences

126 (1) A person is guilty of an offence who,

(a) undertakes an activity without a licence for which a licence is required under this Act and for which a person has not been granted an exemption from the requirement to hold a licence;

(b) knowingly furnishes false or misleading information in any application, statement or return made under this Act or in any circumstances where information is required or

authorized to be provided under this Act;

(c) fails to comply with a condition of a licence or an order of the Board made under this or any other Act;

(c.1) fails to comply with an assurance of voluntary compliance given under section 112.7;

(c.2) fails to comply with an assurance of voluntary compliance entered into under section 88.8 before that section was repealed;

(d) contravenes this Act, the regulations or a rule made under section 44; or

(e) contravenes the *Energy Consumer Protection Act, 2010* or the regulations made under it. 1998, c. 15, Sched. B, s. 126 (1); 2002, c. 1, Sched. B, s. 16; 2002, c. 23, s. 4 (20); 2003, c. 3, s. 84 (1, 2); 2010, c. 8, s. 38 (38).

Officers, etc.

(2) It is an offence for any officer or director of a corporation to cause, authorize, permit or acquiesce in the commission by the corporation of an offence mentioned in subsection (1). 1998, c. 15, Sched. B, s. 126 (2).

Penalty

(3) An individual who is convicted of an offence under subsection (1) or (2) is liable to a fine of not more than $100,000 for a first offence and to a fine of not more than $300,000 for a subsequent offence. 1998, c. 15, Sched. B, s. 126 (3); 2003, c. 3, s. 84 (3); 2015, c. 29, s. 20 (1).

Corporations

(4) A corporation that is convicted of an offence under subsection (1) is liable to a fine of not more than $1,000,000 for a first offence and to a fine of not more than $2,000,000 for a subsequent offence. 1998, c. 15, Sched. B, s. 126 (4); 2003, c. 3, s. 84 (4); 2015, c. 29, s. 20 (2).

Increasing fine by amount of monetary benefit

(4.1) Despite the maximum fines set out in subsections (3) and (4), the court that convicts a person of an offence under subsection (1) or (2) may increase the fine imposed on the person by an amount equal to the monetary benefit that was acquired by, or that accrued to, the person as a result of the commission of the offence. 2003, c. 3, s. 84 (5).

Limitation

(5) Subject to subsection (6), no proceeding under this section shall be commenced more than one year after the facts upon which the proceeding is based first came to the knowledge of the Board. 1998, c. 15, Sched. B, s. 126 (5); 2010, c. 8, s. 38 (39).

Same, retailers of electricity and gas marketers

(6) Despite subsection (5), no proceeding under this section shall be commenced against the following persons more than two years after the facts upon which the proceeding is based first came to the knowledge of the Board:

1. A retailer of electricity or a gas marketer.

2. A director or officer of a corporation, where the person referred to in paragraph 1 is a corporation. 2010, c. 8, s. 38 (40).

Section Amendments with date in force (d/m/y)

Order for compensation, restitution

126.0.1 If a person referred to in subsection 126 (6) is convicted of an offence under this Act, the court making the conviction may, in addition to any other penalty, order the person convicted to pay compensation or make restitution. 2010, c. 8, s. 38 (41).

Section Amendments with date in force (d/m/y)

Default in payment of fines

126.0.2 (1) If a fine payable by a person referred to in subsection 126 (6) as a result of a conviction for an offence under this Act is in default for at least 60 days, the Board may disclose to a consumer reporting agency the name of the defaulter, the amount of the fine and the date the fine went into default. 2010, c. 8, s. 38 (41).

Where payment made

(2) Within 10 days after the Board has notice that the fine has been paid in full, the Board shall inform the consumer reporting agency of the payment. 2010, c. 8, s. 38 (41).

Section Amendments with date in force (d/m/y)

Liens and charges

126.0.3 (1) If a fine payable by a person referred to in subsection 126 (6) as a result of a conviction for an offence under this Act is in default for at least 60 days, the Board may by order create a lien against the property of the person who is liable to pay the fine. 2010, c. 8, s. 38 (41).

Liens on personal property

(2) If the lien created by the Board under subsection (1) relates to personal property,

(a) the *Personal Property Security Act*, except Part V, applies with necessary modifications to the lien, despite clause 4 (1) (a) of that Act;

(b) the lien shall be deemed to be a security interest that has attached for the purposes of the *Personal Property Security Act*; and

(c) the Board may perfect the security interest referred to in clause (b) for the purposes of the *Personal Property Security Act* by the registration of a financing statement under that Act. 2010, c. 8, s. 38 (41).

Liens and charges on real property

(3) If the lien created by the Board under subsection (1) relates to real property, the Board may register the lien against the property of the person liable to pay the fine in the proper land registry office and, on registration, the obligation under the lien becomes a charge on the property. 2010, c. 8, s. 38 (41).

Initiation of sale proceedings prohibited

(4) The Board shall not initiate sale proceedings in respect of any real property against which it has registered a lien under subsection (3). 2010, c. 8, s. 38 (41).

Proceeds of sale

(5) If a lien is perfected by registration under subsection (2) or is registered against real property under subsection (3) and the related real or personal property is sold, the Board shall ensure the funds it receives as result of the sale are used to pay the fine. 2010, c. 8, s. 38 (41).

Discharge of lien

(6) Within 10 days after the Board has knowledge of the payment in full of the fine, the Board shall,

(a) discharge the registration of any financing statement registered under clause (2) (c); and

(b) register a discharge of a charge created on registration of a lien under subsection (3). 2010, c. 8, s. 38 (41).

---

v **Section Amendments with date in force (d/m/y)**

Admissibility in evidence of certified statements

126.1 (1) A statement as to,

(a) the licensing or non-licensing of any person;

(b) the filing or non-filing of any document, material or information with the Board;

(c) the date the facts upon which a proceeding is based first came to the knowledge of the Board; or

(d) any other matter pertaining to such licensing, non-licensing, filing or non-filing, purporting to be certified by the registrar of the Board, is, without proof of the office or signature of the registrar, admissible in evidence in any prosecution or other proceeding as proof, in the absence of evidence to the contrary, of the facts stated. 2000, c. 26, Sched. D, s. 2 (13); 2003, c. 3, s. 85 (1, 2); 2019, c. 6, Sched. 2, s. 29.

Certificate of assurance of voluntary compliance

(2) A copy of an assurance of voluntary compliance purporting to be certified by the registrar of the Board is, without proof of the office or signature of the registrar, admissible in evidence in any prosecution or other proceeding as proof, in the absence of evidence to the contrary, of the facts stated. 2003, c. 3, s. 85 (3); 2019, c. 6, Sched. 2, s. 29.

---

v **Section Amendments with date in force (d/m/y)**

Regulations, general

127 (1) The Lieutenant Governor in Council may make regulations,

(a) limiting, restricting or taking away any rights to use or consume gas without charge or at a reduced rate;

(b) requiring the Board to approve or fix rates under section 36;

(b.1) providing for penalties and fines a gas transmitter or gas distributor is required to pay under an Act that the Board may include in approving or fixing rates for the sale, transmission or distribution of gas, for the purposes of paragraph 1 of subsection 36 (3.1);

(c) providing for compensation procedure for the owners of gas or oil rights and the rights to store gas and for the owners of land who are referred to in subsection 38 (2);

(d) Repealed: 2003, c. 3, s. 86 (1).

(e) Repealed: 2001, c. 9, Sched. F, s. 2 (6).

(f) exempting any person from any provision of this Act, subject to such conditions or restrictions as may be prescribed by the regulations;

(g) defining any word or expression used in this Act that is not defined in this Act;

(g.1) Repealed: 2019, c. 6, Sched. 2, s. 24 (1).

(h) delegating all or part of the powers or duties of the Board with respect to the issuance or renewal of licences under Part IV or V to a self-regulatory organization on such conditions as the Lieutenant Governor in Council considers appropriate;

(i) delegating all or part of the powers or duties of the Board under Part IV or V to a tribunal on such conditions as the Lieutenant Governor in Council considers appropriate;

(j) prescribing a date or dates for the purposes of subsection 70 (10), which dates may be different for different classes of distributors;

(j.1) Repealed: 2021, c. 2, Sched. 2, s. 8 (1).

(j.2) Repealed: 2010, c. 8, s. 38 (43).

(j.3) Repealed: 2003, c. 3, s. 86 (3).

(j.4) Repealed: 2010, c. 8, s. 38 (43).

(j.5) Repealed: 2003, c. 3, s. 86 (4).

(j.6), (j.7) Repealed: 2010, c. 8, s. 38 (43).

(j.8) providing for the appointment of prescribed individuals as members of the Board for the purposes of clause 4 (5) (d), and setting out their powers, duties and functions;

(j.9) specifying matters that, for greater certainty, are not matters that may be heard or determined by a panel of commissioners under subsection 4.3 (8);

(j.10) for the purposes of subsections 4.1 (17) and 4.3 (8), providing for and governing the exercise or performance of a power or duty of the Board by another person or entity;

(j.11) prescribing rights, powers or privileges under subsection 4 (2) for the purpose of clause 4.11 (e);

(j.12) governing processes under section 4.4, including,

(i) prescribing other persons for the purposes of subsection 4.4 (1) or (2), and

(ii) requiring that specified persons be included in a process for the purposes of subsection 4.4 (3);

(j.12.1) governing processes under section 4.4.1, including,

(i) prescribing other persons for the purposes of subsection 4.4.1 (1), and

(ii) requiring that specified persons be included in a process for the purposes of subsection 4.4.1 (2);

(j.13) prescribing classes of contracts for the purpose of clause 4.11 (d);

(j.14) REPEALED: 2019, c. 6, Sched. 2, s. 24 (3);

(j.15) prescribing an amount of money for the purpose of clause 90 (1) (b);

(j.16) prescribing criteria for the purpose of clause 90 (1) (d);

(j.16.1) governing exemptions ordered by the Board under subsection 95 (2);

(j.16.2) establishing and governing procedural requirements that apply to determinations of the Board under subsection 95 (2);

(j.17) prescribing provisions of the *Electricity Act, 1998* for the purpose of clause (d) of the definition of "enforceable provision" in section 3;

(j.18) prescribing deferral or variance accounts as deferral or variance accounts that relate to the commodity of gas for the purpose of subsections 36 (4.1) and (4.2) or to the commodity of electricity for the purpose of subsections 78 (6.1) and (6.2), or prescribing rules for determining if a deferral or variance account relates to the commodity of gas for the purpose of subsections 36 (4.1) and (4.2) or to the commodity of electricity for the purpose of subsections 78 (6.1) and (6.2);

(j.19) prescribing periods of time for the purpose of subsections 36 (4.1) and (4.2) and 78 (6.1) and (6.2);

(j.20) governing the making of orders that determine whether and how amounts recorded in deferral or variance accounts shall be reflected in rates for the purpose of sections 36 and 78;

(j.21) governing the awarding of costs under section 30 when section 22.1 is not complied with;

(k) respecting anything that, in this Act, may or must be prescribed or done by regulation;

(l) providing for such transitional matters as the Lieutenant Governor in Council considers necessary or advisable in connection with the implementation of this Act;

(m) respecting any matter that the Lieutenant Governor in Council considers necessary or advisable to carry out effectively the purposes of this Act. 1998, c. 15, Sched. B, s. 127 (1); 2000, c. 26, Sched. D, s. 2 (14); 2001, c. 9, Sched. F, s. 2 (6); 2002, c. 1, Sched. B, s. 18; 2003, c. 3, s. 86 (1-5); 2010, c. 8, s. 38 (43); 2014, c. 7, Sched. 23, s. 15; 2017, c. 2, Sched. 10, s. 2 (13); 2020, c. 12, s. 85 (3); 2019, c. 6, Sched. 2, s. 24 (1-4); 2021, c. 2, Sched. 2, s. 8 (1); 2023, c. 9, Sched. 24, s. 8 (1); 2024, c. 10, s. 10.

(2) Repealed: 2001, c. 9, Sched. F, s. 2 (7).

General or particular

(3) A regulation under this section may be general or particular in its application. 1998, c. 15, Sched. B, s. 127 (3).

Delegation to self-regulatory organization

(4) If a regulation is made under clause (1) (h) delegating powers or duties of the Board to a self-regulatory organization, subsections 6 (4) to (9) and sections 7 and 8 apply, with necessary modifications. 2003, c. 3, s. 86 (6).

Subdelegation

(4.1) A regulation made under clause (1) (b.1) may authorize the Board to determine a matter that may be prescribed by the Lieutenant Governor in Council under that clause. 2020, c. 12, s. 85 (4); 2021, c. 2, Sched. 2, s. 8 (2).

Transition, *Green Energy Act, 2009*

(5) The Lieutenant Governor in Council may make regulations governing transitional matters that, in the opinion of the Lieutenant Governor in Council, are necessary or desirable to facilitate the implementation of amendments to this Act arising from the enactment of the *Green Energy and Green Economy Act, 2009* and to facilitate the implementation of the *Green Energy Act, 2009*. 2009, c. 12, Sched. D, s. 18.

Transition, *Fixing the Hydro Mess Act, 2019*

(6) The Lieutenant Governor in Council may make regulations governing transitional matters that, in the opinion of the Lieutenant Governor in Council, are necessary or desirable to facilitate the implementation of amendments to this Act by Schedule 2 to the *Fixing the Hydro Mess Act, 2019*. 2019, c. 6, Sched. 2, s. 24 (5).

Same

(7) In the event of a conflict between this Act and a regulation made under subsection (6), the regulation prevails. 2019, c. 6, Sched. 2, s. 24 (5).

Regulations, Minister

(8) The Minister may make regulations providing for amounts and classes of amounts a gas transmitter or gas distributor is required to pay that shall not be included in approving or fixing rates for the sale, transmission or distribution of gas, for the purposes of paragraph 2 of subsection 36 (3.1). 2023, c. 9, Sched. 24, s. 8 (2).

Section Amendments with date in force (d/m/y)

Conflict with other legislation

128 (1) In the event of conflict between this Act and any other general or special Act, this Act prevails. 1998, c. 15, Sched. B, s. 128 (1).

Same

(2) This Act and the regulations prevail over any by-law passed by a municipality. 1998, c. 15, Sched. B, s. 128 (2).

Reports on Board effectiveness

128.1 (1) The Board shall, on the request of the Minister, prepare and submit a report to the Minister on the Board's effectiveness in meeting the objectives set out in sections 1, 2, 2.1 and 104.5. 2019, c. 6, Sched. 2, s. 25; 2021, c. 2, Sched. 2, s. 9.

Tabling

(2) The Minister shall submit the report to the Lieutenant Governor in Council and shall then table the report in the Assembly. 2003, c. 3, s. 87.

Section Amendments with date in force (d/m/y)

129 Repealed 2003, c. 3, s. 88.

Section Amendments with date in force (d/m/y)

Transition, uniform system of accounts

130 On the coming into force of section 44, Ontario Regulation 504/97 shall be deemed to be a rule made under that section and the chief executive officer may change or amend the rule in accordance with that section. 1998, c. 15, Sched. B, s. 130; 2003, c. 3, s. 89; 2019, c. 6, Sched. 2, s. 26.

Section Amendments with date in force (d/m/y)

Transition, undertakings

131 Despite the repeal of the *Ontario Energy Board Act* under the *Energy Competition Act, 1998*, any undertaking made to the Lieutenant Governor in Council under the repealed Act, if valid immediately before this section comes into force, continues to be valid and binding. 1998, c. 15, Sched. B, s. 131.

Transition, director of licensing

132 (1) A licence issued by the Board's director of licensing before this section comes into force shall be deemed to be a licence issued by the Board. 2003, c. 3, s. 90.

Same

(2) An order made by the Board's director of licensing before this section comes into force shall be deemed to be an order made by the Board. 2003, c. 3, s. 90.

Same

(3) Any matter pending before the Board's director of licensing when this section comes into force is continued before the Board, subject to the directions of the board of directors. 2003, c. 3, s. 90; 2019, c. 6, Sched. 2, s. 28.

Section Amendments with date in force (d/m/y)

No cause of action, *Fixing the Hydro Mess Act, 2019*

133 (1) No cause of action arises against the Crown, any current or former member of the Executive Council, any current or former employee or agent of or adviser to the Crown, the Board, or any current or former member, employee or agent of the Board, as a direct or indirect result of,

(a) the enactment, operation or administration of any amendment to this Act by Schedule 2 to the *Fixing the Hydro Mess Act, 2019*;

(b) anything done or not done under the amendments to this Act by Schedule 2 to the *Fixing the Hydro Mess Act, 2019*; or

(c) anything related in any way to the involvement of the Government of Ontario in compensation matters, or other aspects of corporate governance, of the Board. 2019, c. 6, Sched. 2, s. 27.

Proceedings barred

(2) No proceeding, including but not limited to any proceeding for a remedy in contract, constructive dismissal, restitution, tort, misfeasance, bad faith, trust or fiduciary obligation, and any remedy under applicable securities laws or any other statute, that is directly or indirectly based on or related to anything referred to in subsection (1) may be brought or maintained against the Crown or against any person referred to in that subsection. 2019, c. 6, Sched. 2, s. 27.

Application

(3) Subsection (2) applies to any action or other proceeding claiming any remedy or relief, including specific performance, injunction, declaratory relief, any form of compensation or damages, or any other remedy or relief, and includes a proceeding to enforce a judgment or order made by a court outside of Canada. 2019, c. 6, Sched. 2, s. 27.

Retrospective effect

(4) Subsections (2) and (3) apply regardless of whether the cause of action on which the proceeding is purportedly based arose before, on or after the day section 28 of Schedule 2 to the *Fixing the Hydro Mess Act, 2019* came into force. 2019, c. 6, Sched. 2, s. 27.

Proceedings set aside

(5) Any proceeding referred to in subsection (2) or (3) commenced before the day referred to in subsection (4) is deemed to have been dismissed, without costs, on that day. 2019, c. 6, Sched. 2, s. 27.

---

v Section Amendments with date in force (d/m/y)

Note: The Crown and its agents are protected from certain liabilities relating to or resulting from amendments made to this Act by the *Electricity Pricing, Conservation and Supply Act, 2002*, or from any action taken pursuant to those amendments or pursuant to regulations made under those amendments. See: 2002, c. 23, s. 6.

TAB 12

EB-2019-0242

Association of Major Power Consumers in Ontario

Application to Review Amendments to the Market Rules made by the Independent Electricity System Operator

---

SUMMARY CLOSING SUBMISSIONS OF THE IESO

December 9, 2019

STIKEMAN ELLIOTT LLP
5300 Commerce Court West
199 Bay Street
Toronto, ON M5L 1B9

Glenn Zacher LSO#: 43625P
gzacher@stikeman.com
Tel: (416) 869-5688

Patrick Duffy LSO#: 50187S
pduffy@stikeman.com
Tel: (416) 869-5257
Fax: (416) 947-0866

Lawyers for the IESO

I. OVERVIEW

1. The central issue before the Board in this proceeding is the Association of Major Power Consumers of Ontario's (**AMPCO**) claim that it is "unjustly discriminatory" to amend the market rules (the **Amendment**) to expand the current demand response auction (**DRA**) from a demand response-only auction to a technology neutral capacity auction without first addressing whether demand response (**DR**) resources should be entitled to energy payments in the IESO's real-time energy market (**Energy Market**). In the absence of such payments, AMPCO alleges that DR resources will be at a *competitive disadvantage* vis-à-vis generation resources *in the capacity auction* because some DR resources may have to include Energy Market activation costs in their capacity auction bids.

2. On this issue, the evidence before the Board demonstrates that DR resources will not be at a competitive disadvantage and the Amendment is not unjustly discriminatory because:

(a) *The Amendment treats DR and generation resources equally in the capacity auction* – All DR and generation resources that successfully bid into the capacity auction receive the same availability payments irrespective of whether they are subsequently economically activated in the Energy Market.

(b) *The Amendment will not place DR resources at a competitive disadvantage in the capacity auction* – The Amendment will not affect DR resources' competitiveness since there is no evidence or reasonable grounds to support AMPCO's claim that some DR resources may have to include Energy Market activation costs in their capacity auction bids in order to protect against the risk of being economically dispatched in the Energy Market. DR resources can manage and eliminate any material risk and cost of activation in the Energy Market by including economic activation costs *in their Energy Market bids*. The only activation costs which DR resources cannot manage or recover through their energy market bids are the potential costs of certain out-of-market emergency and test activations, which DR resources are compensated for through out-of-market payments. As further explained below, the IESO treats DR resources and generators equivalently in this respect by compensating both for out of market start-up or activation costs which they cannot manage through their Energy Market offers/bids.

(c) *The Amendment will level the playing field* – The Amendment, far from discriminating, will remedy discrimination by opening up the formerly exclusive DR-only DRA to competition by other resources capable of providing the same capacity service. It will also address other system reliability needs and objectives identified by the IESO.

3. Lastly, while DR resources' claimed entitlement to energy payments is a larger market design question that is not the subject of this proceeding, AMPCO has indirectly put this in issue by claiming that it is unjust for the IESO to implement a capacity auction *without first* addressing this matter.[1] In this regard, it is important to make two observations. First, there is nothing inherently discriminatory or unfair in the fact that DR resources do not receive energy payments. There are sound economic and policy reasons why Ontario's Market Design Committee recommended and the government selected a market design which does not pay loads for not consuming energy. Second, while the evidence before the Board is that there is likely not a case for changing Ontario's market design to provide energy payments to DR resources, the IESO is nonetheless undertaking a comprehensive Energy Payments stakeholder engagement and third-party study (**Energy Payments Engagement)** to reconsider the market rules governing energy payments and if this process warrants market design changes, market rule amendments will follow. This is the appropriate forum in which to consider and address the cost/benefit of significant market design changes.

II. LAW

A. Market Rule Review Authority

4. The *Electricity Act, 1998*[2] confers primary authority on the IESO to make market rules, subject to limited rights to seek Board review. One of the limitations included in section 33(5) of the *Electricity Act* is the prohibition that no person may apply for Board review of a market rule that was made by the Minister of Energy before market opening on May 1, 2002.

5. Section 33(9) of the *Electricity Act* also limits the scope of Board's review of other market rule amendments to consideration of whether the amendment is inconsistent with the purposes of the *Electricity Act* or unjustly discriminatory. Notably, in the earlier *3x Ramp Rate* decision[3]

---

[1] AMPCO, Notice of Appeal, September 26, 2019, paras 4, 11, 35, 51.
[2] *Electricity Act, 1998*, SO 1998, c 15, Sch A.
[3] Revised Decision and Reasons, EB-2007 (OEB), April 12, 2007 ("***3x Ramp Rate***").

the Board determined that section 33(9) is "a jurisdiction-limiting provision", which precludes broader inquiry into the IESO's rulemaking processes.[4]

6. The Board also confirmed in the *3x Ramp Rate* decision that as with all other applications before the Board the burden of proof is on the applicant, which in this case requires AMPCO to prove on a balance of probabilities that the Amendment unjustly discriminates against DR resources or is inconsistent with the purposes of the *Act*.[5]

B. Criteria for Market Rule Amendment Review

(a) Inconsistency with Purposes of Act

7. The *Electricity Act* contains a number of varied objects; as such, consideration of whether an amendment is inconsistent with the purposes of the Act requires a contextual analysis.[6]

8. A market rule amendment is not inconsistent with the purposes of the Act because it emphasizes certain statutory objects over others. In the *3x Ramp Rate* decision, the Board acknowledged that the impugned amendment might result in a modest increase in consumers bills – which AMPCO argued detracted from the Act's purpose of protecting the interest of consumers with respect to price – but determined that on balance it furthered other purposes, including promoting economic efficiency, reliability and responsible management of electricity resources.

(b) Unjust Discrimination

9. Determining whether a market rule amendment is unjustly discriminatory turns on several considerations. First, it must ordinarily be shown that similarly situated persons have been treated differently;[7] it is not discriminatory to treat different persons differently – e.g., generators who supply energy and DR resources which do not. Indeed, many resource types are treated differently in the IESO market based on their unique characteristics and the services they provide.

10. Second, discrimination *per se* is not unlawful; only *unjust* discrimination. Accordingly, determining whether discrimination is "unjust" requires consideration not only of the interests

---

[4] *3x Ramp Rate*, Appendix A, Oral Decision (Vice Chair Kaiser), March 29, 2007, at pp 87, 90.
[5] *3x Ramp Rate*, at p 18.
[6] *Rizzo & Rizzo Shoes Ltd. (Re)*, [1998] 1 SCR 27 at para 21.
[7] "Complex" Consolidated Edison Co of NY, Inc v FERC, 165 F3d 992, 1012, 334 US App. D.C. 205 (DC Cir 1999); Western Grid Development, LLC, 133 FERC ¶ 61,029 (2010), at para 17.

of the persons complaining of discrimination, but also the legitimate interests of other participants. In this case, it is appropriate to weigh AMPCO's commercial interests in preserving the DRA against the interests of the IESO, consumers, generators and others who support the Amendment on the basis that it will open up competition, promote reliability and lower costs.[8]

11. Third, in "the context of [the Board's] mandate under section 33 of the *Act*, unjust discrimination means unjust *economic discrimination*".[9] As Bonbright observes, some discrimination is inevitable and the real question is whether the discrimination is efficient or inefficient.[10]

12. Lastly, for impugned conduct to be unjustly discriminatory, it must be discriminatory *in effect*, not just in form or theory. Persons complaining of discrimination must adduce evidence proving that the impugned action has had or will have a material discriminatory impact. As the U.S. Supreme Court stated in its seminal decision, *Federal Power Com v. Hope Natural Gas Co.*:

> It is not theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Act is at an end... And he who would upset the rate order under the Act carries the heavy burden of making a convincing showing that it is invalid because it is unjust and unreasonable in its consequences.[11]

III. THE AMENDMENT IS NOT UNJUSTLY DISCRIMINATORY

A. There is no *prima facie* discrimination or unfairness in not paying energy payments to DR resources

13. Since inception, Ontario's Energy Market has treated generation and load participants differently – because they are different. Generators supply energy and receive energy payments for doing so. Loads do not supply energy and therefore do not receive energy payments.

14. Nor do load participants receive energy payments for not consuming energy; although, loads which choose to be dispatchable benefit from avoiding energy consumption at or above market prices at which it is not economic to consume and operate – i.e., when the marginal

---

[8] *3x Ramp Rate*, at pp. 23, 26.
[9] *3x Ramp Rate*, at p 26.
[10] James C. Bonbright et al, *Principles of Public Utility Rates* (2nd Ed), (Arlington: Public Utility Report, 1988), pp. 517-518; See *3x Ramp Rate* at pp. 23-26.
[11] *Federal Power Commission v Hope Natural Gas Co.*, 320 U.S. 591, at p 602; The United States Supreme Court "reaffirm[ed] these teachings of Hope Gas" in *Dusquesne Light Co v Barasch*, 488 US 299, at p 310. See *3x Ramp Rate* at pp. 23, 25.

benefit of consumption exceeds price. Notably, dispatchable loads (**DLs**) have for many years participated in the Energy Market in the absence of a DRA and entitlement to energy payments. They have done so because they benefit from exposure to Energy Market price signals which allow them to curtail consumption and avoid high prices when it is economic to do so.

15. As Ontario's electricity sector evolves, the IESO is considering changes to certain market design features, including, at the request of AMPCO, conducting a comprehensive Energy Payment Engagement to reconsider the market rules governing energy payments.

16. At present, however, the evidence before the Board – from the IESO, the MSP, Dr. Rivard, LEI and Navigant – does not support energy payments for DR resources:

(a) The MSP notes that: "A DR resource that is activated saves the spot price on its demand reduction, analogous to a generator being paid the spot price for its production. On this basis, an energy payment to DR resources looks like a double payment. A number of stakeholders appear to be urging the IESO to accept Order 745 as the definitive ruling on this issue, but the Ontario situation is different and we may not share the same objectives as FERC."[12]

(b) Navigant notes that: "... there is significant disagreement on whether DR resources should receive a utilization payment when they are curtailed [in the Energy Market]" and, in Ontario, the economic efficiency arguments for utilization payments to DR resources are different than in US markets given that "under the current conditions, more DR activation (as a result of bidding into the market at prices lower than traditional generators) would not actually lead to reduced cost to consumers since generators have their compensation guaranteed [under long-term contract or through regulation]".[13] In other words, any reduction in market price may just be offset by Global Adjustment costs.

(c) Dr. Rivard says that it would not be cost-effective to pay DR resources energy payments; and, not paying energy payments DR resources is not "leading to any material inefficiencies in the market".[14] Dr. Rivard further notes that even if the FERC net benefit test were applied, it would rarely if ever be met because of the countervailing effect of the Global Adjustment.[15]

17. AMPCO has not provided any expert evidence or analysis to the contrary. Other than referencing FERC's Order 745 and its "net benefits" test – which was precipitated by concerns about DR resource participation in wholesale markets (which is not a concern in Ontario) and which LEI, Dr. Rivard, Navigant and the IESO says is inapplicable or is unlikely to show any

---

[12] Exhibit K1.6, Tab 12, p 1.
[13] Exhibit K1.6, Tab 8, pp. 6-7, 13-14.
[14] EB-2019-0242, Hearing (November 28, 2019), Vol 2, ("**Hearing Transcripts, Vol 2**"), p 155.
[15] Revised Affidavit of Brian Rivard, dated November 21, 2019, para 91.

benefit in Ontario[16] – AMPCO has not provided any evidence to show that the absence of energy payments for DR resources in Ontario is unjust.

B. The Amendment does not have any discriminatory impact because it will not put DR Resources at a competitive disadvantage in future capacity auctions

18. DR resources' lack of entitlement to energy payments *in the Energy Market* does not put DR resources at any competitive disadvantage vis-à-vis generators *in the capacity auction*.

19. As AMPCO concedes, the risk and associated cost of activation turns on DR resources' *probability of being activated in the Energy Market*[17] which is solely a function of how DR resources bid into the Energy Market and the Energy Market clearing price; it has nothing to do with how DR resources bid into the capacity auction.

20. The uncontroverted evidence before the Board is that it is entirely within DR resources' control to manage the probability or risk of activation by including any economic activation costs in their Energy Market bids; and if they do this, the risk and associated cost of being activated is remote and immaterial. On this point, the evidence is definitive. Mr. Anderson admits that the risk is a "low probability"[18]; the evidence from other witnesses is as follows:

(a) The IESO notes that DRA participants have rarely been activated because their bid prices are far in excess of HOEP. Since the launch of the DRA in 2015, DL bid prices have averaged $1500/MWh and HDR bid prices have averaged $1700/MWh as compared to an average HOEP of $25/MWh. The IESO does not expect the likelihood of economic dispatch to materially increase.

(b) The evidence from LEI and Navigant are that DR resources in Ontario and elsewhere manage their activation costs by including these costs in their Energy Market bids and, as a result, are rarely economically activated. Mr. Goulding observed that any material change in the level of DR resource activations would likely require a "perfect storm".[19] Dr. Rivard said much the same.

(c) The MSP, in a series of reports on the DRA, observed that DR resources have historically managed the risk and cost of activation by bidding high into the Energy Market and there is no reason to expect this to change:

---

[16] See EB-2019-0242, Hearing (November 25, 2019), Vol 1, p. 134-137 ("**Hearing Transcripts, Vol 1**"); Interrogatory Response from London Economics International LLC to Kingston Cogen Limited Partnership, No. 2(d) (November 20, 2019); Revised Affidavit of Brian Rivard, dated November 21, 2019, para 91; Exhibit K1.6, Tab 8, pp. 13-14; EB-2019-0242, Hearing (November 29, 2019), Vol 3, pp. 11-14, ("**Hearing Transcripts, Vol 3**").

[17] Interrogatory Response from AMPCO to Staff No. 3(c) (November 6, 2019).

[18] Hearing Transcripts, Vol 1, p 93.

[19] Hearing Transcripts, Vol 1, p 174.

- "Given the activation criteria..., the likelihood of an activation is remote.... DR resources can bid into the Energy Market at any price between $100/MWh and $2000/MWh"[20]
- "[Since the start of the DRA]... any bid price over $220/MWh would not have been activated .... [and since] 2005 and 2006 [when] all-time demand records were being set in Ontario... no bid price above $1000/MWh would have been activated, yet most HDR resources bid at twice that price.... Even under the most aggressive demand projections peak demand is not expected to return to record 2005 and 2006 levels until 2029".[21]

21. The IESO's witnesses, Ms. Trickey and Mr. Short, stated that DR resources can entirely manage any activation costs by including such costs in their Energy Market bids and if they do this, there is no "actual" or "practical risk" of being activated in the Energy Market.[22]

22. Dr. Rivard also addressed this issue at length in his written evidence and in his oral testimony. Dr. Rivard testified that DR resources can include their activation costs in their Energy Market bids and if they do so, the risk of activation is "theoretical" and the "material risk of activation is not real". Dr. Rivard stated that DR resources are not at any competitive disadvantage to generators in an auction and in response to questions from the Panel and counsel answered that:

> I would say... not getting an energy payment right now, based on history seeing how often [DR resources] would actually be activated is, in my words, de minimus in expectation, in which case [DR resources could] could offer in that capacity auction exactly the same that they would have had generators not been there. And then let's see what competition brings about...
>
> ... If I was working for that [DR] company, and that is when I said, based on the evidence for this next auction, if I was advising my CEO, I would say we're not at risk. I can manage that in my energy bid. We will be as competitive as we can in our capacity auction.[23]

23. The Panel expressed some concern that there may be some "slice of costs" or some "added cost component that generators don't have" when activated and which put DR resources at a "disadvantage" vis-à-vis generators who have their start-up cost guaranteed.[24] That is not the case. The shut-down costs referenced by Mr. Anderson in his hypothetical

---

[20] Exhibit K1.6, Tab 6, p 100.
[21] Exhibit K1.6, Tab 6, p 100-101.
[22] Hearing Transcripts, Vol 3, pp. 23, 24, 33.
[23] Hearing Transcripts, Vol 2, pp. 191, 196, 198, 207.
[24] Hearing Transcripts, Vol 2, p 195; Hearing Transcripts, Vol 3, p 184.

example – e.g., a steel mill that incurs fuel costs to keep steel molten as well as other value of lost load costs – are all activation costs which the hypothetical steel mill customer can include and avoid through its Energy Market bids. The *only* activation costs which DR resources cannot manage or recover through their Energy Market bids are costs of certain out of market activations. However, in this respect, the IESO treats DR resources in the same manner that it treats those generators who cannot recover their start-up costs. As explained below, the IESO compensates DR resources for these otherwise unrecoverable costs through out of market make-whole payments:

(a) Non-quick start generators – The IESO guarantees start-up costs under its Generator Cost Guarantee Program for a subset of non-quick start generators that start/ramp slowly and may not be able to recover these costs through their Energy Market offers and revenues they earn in the Energy Market.[25] These generators may not start/ramp if they do not believe that market prices will be sufficient to recover their start/ramp costs. The IESO therefore, for reliability purposes, launched the GCG Program in 2003 to incent these generators to start and be available when the electricity system needed them by guaranteeing certain start-up costs *if* these costs were not recovered in the Energy Market revenues.

(b) DL and HDR resources – The IESO likewise compensates DL and HDR resources for out-of-market emergency or test activations. DLs have been entitled to compensation for out-of-market activations. More recently, HDR resources sought compensation for these activations on the basis that they *currently included such costs in their DRA capacity bids*, but circumstances would change in the "proposed capacity auctions, where HDR will be competing against other resource types".[26] The IESO therefore amended the market rules to allow for recovery of these out-of-market emergency and test activation costs on the basis that these costs – like certain start-up costs incurred by non-quick start generators – could not be recovered through HDR resources' Energy Market bids.

---

[25] For a discussion on the Generator Cost Guarantee Program, see Hearing Transcripts, Vol 3, pp 27-39.
[26] AMPCO, Notice of Appeal, Footnote 14, pp. 2-6 of 16.

24. In short, DR resources are treated in the same manner as generators and are not exposed to any Energy Market activation costs that they cannot manage through their Energy Market bids or through make-whole payments for out of market activations.

C. The Amendment will level the playing field, remedy any discrimination and address other important purposes of the Act

25. The Amendment and future capacity auctions will not, as AMPCO contends, discriminate against DR resources. To the contrary, they will remedy discrimination by opening up the DR-only DRA to all resources capable of cost-effectively supplying capacity, including off-contract generators, storage resources and imports.

26. The IESO commenced its capacity auction initiative with the DRA as a first step, in part, to learn how to integrate DR resources into the IESO markets, help remove some of the barriers to participation by DR resources and ready DR resources for a broader capacity auction.

27. DR resources have benefited from an exclusive DRA and some AMPCO members may have a vested commercial interest in preserving a DR-only auction in which they do not have to compete; however, AMPCO's argument that delaying the broadening of the DRA will promote competition is misplaced. DR resources, will be able to compete on a level playing field with all other capacity resources and opening up the auction will enhance competition and deliver the benefits of competition to Ontario electricity consumers.

28. AMPCO, having succeeded on the stay motion, has maintained the DRA and delayed competition for another year (for the period May 1, 2020 to April 30, 2021); but if the IESO is further prevented from proceeding with a capacity auction, it will have to consider other options for addressing the significant capacity gap starting in 2023. These include re-contracting with generators and other supply resources, which are less competitive and less cost-effective solutions, and ultimately, will not benefit Ontario electricity consumers.

29. Determining whether the Amendment is *unjustly* discriminatory requires consideration of not only AMPCO's members' commercial interest, but of the IESO's statutory objects and the legitimate interests of other electricity sector participants. In this case, the IESO, which is statutorily responsible for maintaining system reliability and administering Ontario's wholesale markets, has given evidence that there are, in addition to the benefits of opening up competition, important system reliability reasons for proceeding with a capacity auction. The IESO's evidence, which has not been seriously challenged, should be given due weight. The

interests of the majority of consumers, whose representatives on the IESO's Technical Panel voted in favour of the Amendment and want the capacity auction to proceed, also warrant consideration, as do the competing commercial interests of KCLP, APPrO and other generators — who to date have not had an equal opportunity to compete to supply capacity.

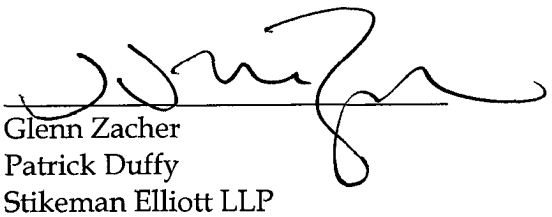
D. The Amendment itself is not alleged to be discriminatory

30. Lastly, AMPCO does not allege that there is anything discriminatory in the Amendment itself. Instead, AMPCO argues that the Amendment has simply made more acute AMPCO's long-standing complaint that load resources are inequitably treated in the Energy Market.

31. AMPCO's position raises an important jurisdictional issue. By asking the Board to revoke the Amendment — which in and of itself AMPCO has no objection to — and thereby prevent the IESO from proceeding with a capacity auction *until* the original market rules governing energy payments are amended, AMPCO is, in effect, challenging government-made market rules which the *Electricity Act* expressly prohibits AMPCO from challenging.

32. For all of the reasons stated herein, the IESO respectfully submits that AMPCO's application to revoke the Amendment should be dismissed and the IESO should be permitted to proceed with its planned capacity auction.

ALL OF WHICH IS RESPECTFULLY SUBMITTED this 9th day of December 2019.



Glenn Zacher
Patrick Duffy
Stikeman Elliott LLP