EB-2019-0242

ONTARIO ENERGY BOARD

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO)

Application for Review of an Amendment to the Independent Electricity System Operator Market Rules

COMPENDIUM FOR ARGUMENT

INDEX

TAB 1

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2019-0242**	**AMPCO Motion**
VOLUME:	**1**	
DATE:	**November 25, 2019**	
BEFORE:	**Cathy Spoel**	**Presiding Member**
	Emad Elsayed	**Member**
	Susan Frank	**Member**

coincident peak basis, which is consistent with what other jurisdictions do. And the reason for that is they don't -- it's not because of the industrials that those peaks occur. Those peaks occur because of the rest of us, residential and commercial, and we crank up the air-conditioning when it gets hot for the third day in a row. That's not the industrials. They're not creating the peak problem. They're providing a solution.

MS. KRAJEWSKA: Mr. Anderson, in terms of -- my last question to you is, you say that the amendments are discriminatory, and I appreciate that you stated that you weren't an economist, but how should the OEB evaluate the discrimination? Should it be on the basis of horizontal equity, vertical equity? What would you -- how would you state that the OEB should evaluate the discrimination?

MR. ANDERSON: I am certainly not even going to try to frame it within the context of economic parlance.

What I am going to say to the Board is that we have two entities that are participating in the same auction. One of those entities gets two payment streams, the other gets one for providing the same thing.

That seems discriminatory in nature to me, and it is driven exclusively by the amendment impacts or the impacts of the amendments as currently crafted. That is the practical man's approach to it, as opposed to the economist's.

MS. KRAJEWSKA: Thank you. Those are my questions.

MS. SPOEL: Thank you. Mr. Zacher, I think you are

TAB 2

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2019-0242**	**AMPCO Motion**
VOLUME:	**2**	
DATE:	**November 28, 2019**	
BEFORE:	**Cathy Spoel**	**Presiding Member**
	Emad Elsayed	**Member**
	Susan Frank	**Member**

don't think anybody knows where the clearing price is. That will depend upon the supply-demand equation that gets set up by the IESO when they run the auction, and it will depend on what participants feel that they actually need, the minimum amount that is, of revenues that they actually need to be involved in that auction.

MR. MONDROW: Mr. Windsor, would KCLP support a market rule for a capacity auction under which generators providing the capacity were not eligible for energy payments upon activation?

MR. WINDSOR: I'm sorry, could you repeat the question?

MR. MONDROW: Would KCLP support a market rule for capacity auction under which generators providing the capacity were not eligible for energy payments when activated?

MR. WINDSOR: In this current environment, if there was absolutely nothing else as a stop-gap, we might consider it.

MR. MONDROW: You hesitate. Why do you hesitate?

MR. WINDSOR: Because I never considered it before.

MR. MONDROW: If that happened, you would be unable to recover, if activated, your variable costs, variable generation costs.

MR. WINDSOR: We have a view of the market. And like I said before, I really don't think there is much concern about activation. We could forego the cost of being activated a couple of times over the period of a year, if we thought we were going to be rewarded with a capacity payment.

MR. MONDROW: Did you ever advocate that to the IESO?

MR. WINDSOR: No.

MR. MONDROW: Never thought of it before?

MR. WINDSOR: That's probably correct.

MR. MONDROW: Do you think that would, that kind of capacity auction would be -- would result in fair competition?

MR. WINDSOR: No.

MR. MONDROW: Why?

MR. WINDSOR: I think, under that kind of a framework, I think generators would be unfairly positioned --

MR. MONDROW: Why is that?

MR. WINDSOR: -- in the auction.

MR. MONDROW: Why is that?

MR. WINDSOR: Because in the event they actually are Activated, they're paying for it out of their own pocket.

MR. MONDROW: Would that not be true for DR resources as well?

MR. WINDSOR: We talked about that yesterday -- well, others talked about that Monday, in the previous hearing sessions. And we -- and I will leave that to the economists. I have my own personal view.

I think loads are getting compensation in at least one or two other buckets under the capacity program.

MR. MONDROW: I don't understand. Could you elaborate?

MR. WINDSOR: A little bit. I will make reference to the discussion about the ICI, and I will make reference to the discussion about when load turns down, in theory the energy price in the market drops and whatever load they are consuming at that point in time, they are consuming at a lower rate.

So therefore, I am saying they're getting two forms of different compensation as a result of an activation.

MR. MONDROW: Do generators get compensation in the IAM, the IESO-administered market, other than energy payments?

MR. WINDSOR: It depends on what program you are participating in.

MR. MONDROW: There are programs that generators can participate in that provide other revenue streams?

MR. WINDSOR: If the generator qualifies.

MR. MONDROW: Does KCLP participate in any of those programs?

MR. WINDSOR: KCLP right now is participating in the energy program in Ontario.

MR. MONDROW: Sorry, does that mean it does not participate in any other program other than the energy market?

MR. WINDSOR: That's correct, to the best of my knowledge.

MR. MONDROW: Okay. Mr. Windsor, does KCLP qualify for no speed no load start-up costs?

MR. WINDSOR: I think what you're making reference to

TAB 3

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2019-0242**	**AMPCO Motion**
VOLUME:	**1**	
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BEFORE:	**Cathy Spoel**	**Presiding Member**
	Emad Elsayed	**Member**
	Susan Frank	**Member**

MR. ANDERSON: Correct.

MR. ZACHER: And the rules with regards to bidding are roughly commensurate or equivalent for both?

MR. ANDERSON: For capacity.

MR. ZACHER: And both generators and loads will receive availability payments?

MR. ANDERSON: They will.

MR. ZACHER: And the rules with regards to settlement are equivalent. You haven't identified any deficiencies or any differences in that respect?

MR. ANDERSON: I am going to actually take you to the market rules, if we want to go there. Do you mind? To answer your question?

MR. ZACHER: Sure.

MR. ANDERSON: Okay. I would like to -- it is -- the market rules themselves are shown at AMPCO's notice of appeal, footnote 1, page -- starting at page 6 of 60. Can we get that put up? It is actually page 7 of 60, my apologies. No, sorry, it is the actual notice of appeal, so the initial document that was filed by AMPCO to start this application. And it has a number of attachments at the back of it by footnote number. One of them is footnote 1, page 7 of 60.

MR. MONDROW: That's the correct tab. And if you look at the top of the page, each page has a header on it with a page number. So you see that is page 1 of 60, so six pages forward should be page 7 of 60.

MR. ANDERSON: Thank you, Mr. Mondrow. That's it.

So page 7 defines a number of new definitions, definitions that had not previously existed. And just at the very bottom of the screen right now -- thank you for that -- you will see -- yes, that's good -- "capacity auction eligible generation resource". That is a new definition. And CAEGR is now allowed to participate.

And if we scroll back up again, it is now allowed to participate in the capacity auction, which you will see in the middle of the page means a transitional capacity auction or a demand response auction. It was previously just a demand response auction. Now it is both.

Those changes in definition introduced a new type of participant into what was the demand response auction, but is now the capacity auction, or the TCA. That new participant has a new and different revenue structure than all of the previous DRA participants.

These two participant types now share the TCA, which had been exclusively, I think as you have said, the demand response auction, which had only one type of participant.

So if we can go down further to Chapter 7, section 19.1 -- sorry, I will try to find that and tell you what page it is. Page 18 of 21. I am not sure what footnote it was.

MR. MONDROW: So that would be I think still footnote 1 --

MR. ANDREW: It should be 1, I think.

MR. MONDROW: Page 29 of 40 at the top of the page. Is this what you are referring to, Mr. Anderson?

MR. ANDERSON: I am trying to get to Chapter 7, section 19.1, which combines all of the above and sets out the generators now qualify for the amended auction.

MR. MONDROW: Sorry, bear with me. I gave you the wrong -- a different reference. Ms. van Soelen I think may have found it. Try footnote 1 still. Page 44 of 60. Try footnote 1 still, page 44 of 60.

MS. SPOEL: Mr. Mondrow, our copies -- the top of the page was cut off, so we don't have the page numbers. If you can give us the page number at the bottom of the page as well, that will help us to navigate.

MR. MONDROW: I will certainly do that.

MR. MONDROW: Sorry, Mr. Anderson, what section are you trying to refer to? There should be a section number, and then I can get a page number.

MR. ANDERSON: It was supposed to be section 19.1, according to my notes.

MR. MONDROW: 19.1. Okay, I have it.

MS. SPOEL: Mr. Mondrow --

MR. ANDERSON: Sorry. The page number at the bottom is 18 of 21. At the top, it is 29 of 60 in footnote 1. My apologies.

MS. SPOEL: Is that the one that starts with 19.1, purpose?

MR. ANDERSON: Yes. That's it, thank you. My apologies for that. I didn't mean to torture you.

MS. SPOEL: Thank you.

MR. ANDERSON: The combination of the new definitions for capacity auction, the new definitions that set out the CAEGR generation definition, and this section 19.1, which permits in 19.1.2.3 generators to now participate, is sufficient to change the landscape from a DRA that was exclusive to loads to a CA that now includes a second class of participant, who has a very different payment structure than the existing loads that were in the DRA.

So from my perspective, the amendments do in fact have a discriminatory impact in the changes that are contemplated within those amendments, and that impact is what AMPCO has objected to. And the reason it has chosen now to object to it so strongly is that this is the point where the generators have formally been introduced, creating that second class of market participant, who gets a different payment stream than the DR proponents that were in it before.

MR. ZACHER: Okay. Well, listen, I don't want to belabour it, but effectively you're saying the TCA rules have fundamentally changed because a new class of participants can now participate in the auction. Do you agree with that?

MR. ANDERSON: I agree that a new class of participant is participating, yes.

MR. ZACHER: Right. It used to just be demand resources. Now certain generators can participate.

MR. ANDERSON: That's correct.

MR. ZACHER: And the rules, not surprisingly, have created a new definition to recognize the new class of

TAB 4

Ontario

Français

Electricity Act, 1998

S.O. 1998, CHAPTER 15
SCHEDULE A

Consolidation Period: From March 26, 2019 to the e-Laws currency date.

Last amendment: 2019, c. 1, Sched. 4, s. 16.

Legislative History: [+]

CONTENTS [−]

PART I
GENERAL

Purposes

1 The purposes of this Act include the following:

(a) to ensure the adequacy, safety, sustainability and reliability of electricity supply in Ontario through responsible planning and management of electricity resources, supply and demand;

(a.1) to establish a mechanism for energy planning;

(b) to encourage electricity conservation and the efficient use of electricity in a manner consistent with the policies of the Government of Ontario;

(c) to facilitate load management in a manner consistent with the policies of the Government of Ontario;

(d) to promote the use of cleaner energy sources and technologies, including alternative energy sources and renewable energy sources, in a manner consistent with the policies of the Government of Ontario;

(e) to provide generators, retailers, market participants and consumers with non-discriminatory access to transmission and distribution systems in Ontario;

(f) to protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service;

(g) to promote economic efficiency and sustainability in the generation, transmission, distribution and sale of electricity;

(g.1) to facilitate the alteration of ownership structures of publicly-owned corporations that transmit, distribute or retail electricity;

(g.2) to facilitate the disposition, in whole or in part, of the Crown's interest in corporations that transmit, distribute or retail electricity, and to make the proceeds of any such disposition available to be appropriated for any Government of Ontario purpose;

(h) to ensure that Ontario Hydro's debt is repaid in a prudent manner and that the burden of debt repayment is fairly distributed;

(i) to facilitate the maintenance of a financially viable electricity industry; and

(j) to protect corridor land so that it remains available for uses that benefit the public, while recognizing the primacy of transmission uses. 2004, c. 23, Sched. A, s. 1; 2014, c. 7, Sched. 7, s. 1; 2015, c. 20, Sched. 9, s. 1; 2016, c. 10, Sched. 2, s. 1.

Section Amendments with date in force (d/m/y) [+]

Interpretation

2 (1) In this Act,

"affiliate", with respect to a corporation, has the same meaning as in the *Business Corporations Act*; ("membre du même groupe")

"alternative energy source" means a source of energy,

(a) that is prescribed by the regulations or that satisfies criteria prescribed by the regulations, and

(b) that can be used to generate electricity through a process that is cleaner than certain other generation technologies in use in Ontario before June 1, 2004; ("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")

"Board" means the Ontario Energy Board; ("Commission")

"charges" means, with respect to the IESO, amounts charged by the IESO, or by a predecessor within the meaning of section 4, to recover amounts paid or payable by the IESO or the predecessor to another person with respect to electricity; ("frais")

(7) The Board shall forward a copy of an application filed under subsection (6) to the distributor before commencing its review. 2005, c. 33, s. 5.

Review by Board

(8) Upon receipt of an application under subsection (6), the Board shall review the matter and, upon the completion of its review, if it finds that the distributor acted unreasonably in shutting off the distribution of electricity to the property or in failing to restore the distribution of electricity to the property, may make an order directing the distributor to restore the distribution of electricity to the property, subject to any requirements under Part VIII. 2005, c. 33, s. 5.

Termination not a breach of contract

(9) If the Board finds that the distributor did not act unreasonably in shutting off the distribution of electricity to a property under subsection (1), the shut-off of the distribution of electricity to the property shall be deemed not to be a breach of any contract. 2005, c. 33, s. 5.

Section Amendments with date in force (d/m/y) [+]

Market Rules

Market rules

32 (1) The IESO may make rules,

(a) governing the IESO-controlled grid;

(b) establishing and governing markets related to electricity and ancillary services; and

(c) establishing and enforcing standards and criteria relating to the reliability of electricity service or the IESO-controlled grid, including standards and criteria relating to electricity supply generated from sources connected to a distribution system that alone or in aggregate could impact the reliability of electricity service or the IESO-controlled grid. 1998, c. 15, Sched. A, s. 32 (1); 2004, c. 23, Sched. A, s. 41 (1, 2); 2009, c. 12, Sched. B, s. 11 (1).

Examples

(2) Without limiting the generality of subsection (1), the market rules may include provisions,

(a) governing the making and publication of market rules;

(b) governing the conveying of electricity into, through or out of the IESO-controlled grid and the provision of ancillary services;

(c) governing standards and procedures to be observed in system emergencies;

(d) authorizing and governing the giving of directions by the IESO, including,

(i) for the purpose of maintaining the reliability of electricity service or the IESO-controlled grid, directions requiring persons, including persons providing electricity supply generated from sources connected to a distribution system, within such time as may be specified in the direction, to synchronize, desynchronize, increase, decrease or maintain electrical output, to take such other action as may be specified in the direction or to refrain from such action as may be specified in the direction, and

(ii) other directions requiring market participants, within such time as may be specified in the direction, to take such action or refrain from such action as may be specified in the direction, including action related to a system emergency; and

(e) authorizing and governing the making of orders by the IESO, including orders,

(i) imposing financial penalties on market participants,

(ii) authorizing a person 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, or

(iii) terminating, suspending or restricting a person's rights 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. 1998, c. 15, Sched. A, s. 32 (2); 2004, c. 23, Sched. A, s. 41 (2-6); 2009, c. 12, Sched. B, s. 11 (2).

General or particular

(3) A market rule may be general or particular in its application. 1998, c. 15, Sched. A, s. 32 (3).

***Legislation Act, 2006*, Part III**

(4) Part III (Regulations) of the *Legislation Act, 2006* does not apply to the market rules or to any directions or orders made under the market rules. 1998, c. 15, Sched. A, s. 32 (4); 2006, c. 21, Sched. F, s. 136 (1).

Publication and inspection of market rules

(5) The IESO shall publish the market rules in accordance with the market rules and shall make the market rules available for public inspection during normal business hours at the offices of the IESO. 1998, c. 15, Sched. A, s. 32 (5); 2004, c. 23, Sched. A, s. 41 (7).

Notice to Board

(6) The IESO shall not make a rule under this section unless it first gives the Board an assessment of the impact of the rule on the interests of consumers with respect to prices and the reliability and quality of electricity service. 2004, c. 23, Sched. A, s. 41 (8).

Transition

(7) All rules made before subsection 4 (1) of Schedule A to the *Electricity Restructuring Act, 2004* comes into force remain in effect until amended or revoked in accordance with this Act. 2004, c. 23, Sched. A, s. 41 (8).

(8), (9) Repealed: 2004, c. 23, Sched. A, s. 41 (8).

Section Amendments with date in force (d/m/y) [+]

Amendment of market rules

33 (1) The IESO shall, in accordance with the market rules, publish any amendment to the market rules at least 22 days before the amendment comes into force. 2004, c. 23, Sched. A, s. 42.

Notice to the Board

(2) The IESO shall give the Board a copy of the amendment and such other information as is prescribed by the regulations on or before the date the IESO publishes the amendment under subsection (1). 2004, c. 23, Sched. A, s. 42.

Board's power to revoke

(3) Despite section 4.1 of the *Statutory Powers Procedure Act* and section 35.1 of this Act, the Board may, not later than 15 days after the amendment is published under subsection (1) and without holding a hearing, revoke the amendment on a date specified by the Board and refer the amendment back to the IESO for further consideration. 2004, c. 23, Sched. A, s. 42.

Application for review

(4) Any person may apply to the Board for review of an amendment to the market rules by filing an application with the Board within 21 days after the amendment is published under subsection (1). 2004, c. 23, Sched. A, s. 42.

Application of *Ontario Energy Board Act, 1998*

(5) Subsection 19 (4) of the *Ontario Energy Board Act, 1998* applies to an application under subsection (4). 2004, c. 23, Sched. A, s. 42.

Review by Board

(6) The Board shall issue an order that embodies its final decision within 120 days after receiving an application for review of an amendment. 2004, c. 23, Sched. A, s. 42; 2017, c. 2, Sched. 10, s. 1.

Stay of amendment

(7) No application for review of an amendment under this section shall stay the operation of the amendment pending the completion of the Board's review of the amendment unless the Board orders otherwise. 2004, c. 23, Sched. A, s. 42.

Same

(8) In determining whether to stay the operation of an amendment, the Board shall consider,

(a) the public interest;

(b) the merits of the application;

(c) the possibility of irreparable harm to any person;

(d) the impact on consumers; and

(e) the balance of convenience. 2004, c. 23, Sched. A, s. 42.

Order

(9) 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 class of market participants, the Board shall make an order,

(a) revoking the amendment on a date specified by the Board; and

(b) referring the amendment back to the IESO for further consideration. 2004, c. 23, Sched. A, s. 42.

Section Amendments with date in force (d/m/y) [+]

Urgent amendments

34 (1) Section 33 does not apply if the IESO files a statement with the Board indicating that, in its opinion, an amendment to the market rules is urgently required for one or more of the following reasons:

1. To avoid, reduce the risk of or mitigate the effects of conditions that affect the ability of the integrated power system to function normally.
2. To avoid, reduce the risk of or mitigate the effects of the abuse of market power.
3. To implement standards or criteria of a standards authority.
4. To avoid, reduce the risk of or mitigate the effects of an unintended adverse effect of a market rule.
5. A reason prescribed by the regulations. 1998, c. 15, Sched. A, s. 34 (1); 2002, c. 23, s. 3 (14); 2004, c. 23, Sched. A, s. 43 (1).

Publication of urgent amendment

(2) The IESO shall publish the amendment in accordance with the market rules at the same time or as soon as reasonably possible after the statement referred to in subsection (1) is filed. 1998, c. 15, Sched. A, s. 34 (2); 2004, c. 23, Sched. A, s. 43 (2).

Notice to the Board

(2.1) The IESO shall give the Board a copy of the amendment and such other information as may be prescribed by the regulations on or before the date the IESO publishes the amendment under subsection (2). 2004, c. 23, Sched. A, s. 43 (3).

Board's power to revoke

(2.2) Despite section 4.1 of the *Statutory Powers Procedure Act* and section 35.1 of this Act, the Board may, not later than 15 days after the amendment is published under subsection (2) and without holding a hearing, revoke the amendment on a date specified by the Board and refer the amendment back to the IESO for further consideration. 2004, c. 23, Sched. A, s. 43 (3).

Review by Board

(3) On application by a person who is directly affected by the amendment, the Board shall review the amendment. 1998, c. 15, Sched. A, s. 34 (3); 2002, c. 23, s. 3 (17).

Time for application

TAB 5

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2007-0040

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

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

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

BEFORE:	Gordon Kaiser Presiding Member and Vice Chair
	Pamela Nowina Member and Vice Chair
	Bill Rupert Member

The Application

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

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

The specific relief sought in the Application is the following:

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

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

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

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

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

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

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

The Amendment

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

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

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

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

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

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

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

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

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

The Proceeding

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

1. *Stay of Operation of the Amendment*

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

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

By Order dated February 9, 2007, the Board stayed the operation of the Amendment pending completion of the Board’s review of the Amendment and issuance by the Board of its order embodying its final decision on AMPCO's application for review of the Amendment. The Board noted in particular that the balance of convenience favoured a stay of the operation of the Amendment, particularly given the long history of the ramp rate issue in the IESO-administered markets.

2. Intervenors

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

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

3. *Procedural Order No. 1*

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

- indicated that cost awards would be made available in this proceeding to eligible intervenors, and solicited written submissions on the issue of the party from whom cost awards should be recovered;
- directed the IESO to file materials associated with the development and adoption of the Amendment; and
- identified the following as the issues to be considered in this proceeding:
  - (i) is the Amendment inconsistent with the purposes of the Act?
  - (ii) does the Amendment unjustly discriminate against or in favour of a market participant or a class of market participants?

4. *Cost Awards*

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

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

5. *Production of Materials by the IESO*

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

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

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

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

6. *Technical Conference*

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

7. *Submissions on the "Relevance Issue"*

On March 21, 2007, AMPCO filed with the Board a letter setting out a proposal for submissions on the issue of the relevance of certain materials to this proceeding. As noted above, in its Procedural Order No. 2 the Board invited parties to make submissions on the relevance of the DAM/DACP Materials. AMPCO's proposal, made with the consent of the IESO, was to the effect that AMPCO would provide the Board and all parties with a "comprehensive submission on the relevance of materials produced by the IESO in relation to a central theme contained in AMPCO's application: "that the Amendment violates fundamental principles of procedural fairness". The proposal also suggested that, rather than filing submissions in accordance with Procedural Order No. 2, parties should await production of AMPCO's comprehensive submission and respond to that document.

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

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

8. *The Oral Hearing and Final Written Argument*

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

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

The Board's Mandate

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

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

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

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

By contrast, the position of the IESO, APPrO, Coral, OPG and TransCanada is that the Board's mandate is limited by section 33(9) of the Act to a determination of whether (a) the amendment is inconsistent with the purposes of the Act; or (b) the amendment unjustly discriminates against or in favour of a market participant or a class of market participants. On that basis, whether the IESO has, and breached, a common law duty of procedural fairness or acted in a manner giving rise to a reasonable apprehension of bias (both of which allegations were denied by the IESO), are not matters for consideration by the Board on a market rule amendment review application under section 33 of the Act. Materials produced by the IESO that are relevant only to the IESO's processes in making the Amendment should therefore be disregarded. The IESO also specifically requested that the Board strike AMPCO's March 26, 2007 submission from the record.

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

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

The Impact of the Amendment

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Parties Supporting the Amendment

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

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

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

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

Similar to the IESO, APPrO submits that improvements resulting from implementation of the Amendment are consistent with the purposes set out in sections 1(b), 1(c), 1(f), 1(g) and 1(i) of the Act. According to APPrO, the Amendment addresses many of the challenges and inefficiencies resulting from the use of the 12x ramp rate multiplier by creating just price signals for generators and loads, and does so with minimal, if any, customer cost impacts. APPrO also argues that the effects resulting from the 12x ramp rate multiplier are prejudicial to, and discriminate against, consumers and suppliers. APPrO states that, by more closely aligning the pricing algorithm with the dispatch algorithm, the Amendment would mitigate those prejudicial and discriminatory effects (such effects including that consumers are not paying the true cost of the electricity they consume and are paying for inefficiencies through uplift charges).

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

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

<u>Parties Opposing the Amendment</u>

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

TAB 6

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

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

DECISION ON COST RESPONSIBILITY & COST ELIGIBILITY

November 12, 2019

On September 26, 2019, the Association of Major Power Consumers in Ontario (AMPCO) filed a Notice of Appeal (Application) asking the Ontario Energy Board (OEB) to review and issue an order revoking amendments to the market rules made by the Independent Electricity System Operator (IESO) (MR-00439-R00 to -R05) (Amendments), and referring the Amendments back to the IESO for further consideration. The Amendments enable the evolution of the IESO's Demand Response Auction into a Transitional Capacity Auction (TCA), including allowing participation by certain generators. The Application was filed under section 33 of the *Electricity Act, 1998*, S.O. 1998, c. 15, (Schedule B) (Act).

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).

On October 18, 2019, the OEB issued Procedural Order No. 2 (PO 2) which indicated, among other things, that the OEB will make cost awards available in this proceeding to eligible parties and granted intervenor status to all parties that requested it, as follows:

- 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 (filed on October 17, 2019)

In its Application, AMPCO requested eligibility to seek recovery of its reasonably incurred costs of the Application and the Motion. APPrO and SEC also applied for cost award eligibility in their Notices of Intervention. KCLP, in its Notice of Intervention, submitted that, if AMPCO is granted cost award eligibility, it should also be eligible for an award of costs.

In PO 2, the OEB stated that it intends for the IESO to bear the costs of this proceeding, as this is consistent with the overall legislative scheme, which contemplates a review by the OEB as a potential last step in relation to market rule amendments. The OEB also noted that this was the outcome in the two preceding applications before the OEB to review market rule amendments: EB-2013-0029 / EB-2013-0010 (RES Proceeding) and EB-2007-0040 (Ramp Rate Proceeding).

The OEB did, however, allow the IESO an opportunity to make a submission if it wished to object to bearing the costs of this proceeding, and if it wished to object to any of the requests for cost award eligibility made by AMPCO, APPrO, SEC and KCLP. Provision was also made for a reply submission by any party whose request for cost award eligibility was the subject of an objection by the IESO.

Cost Responsibility

Submissions of the Parties

IESO Submission

On October 23, 2019, the IESO filed its submission (IESO Submission) stating, among other things, that the OEB should defer its determination of who should be responsible for costs until the end of this proceeding, when the OEB will be better positioned to decide whether ‘special circumstances’ have been demonstrated that warrant a departure from the presumptive rule that (i) applicants bear their own costs, and (ii) parties pursuing their own commercial interests are not eligible for cost awards.

The IESO submitted that the two earlier market rule review proceedings are not dispositive with respect to cost responsibility in an application under section 33 of the Act, and further submitted that it disagreed with the OEB’s view, as expressed in PO 2, that making the IESO responsible for costs is consistent with the legislative scheme. The IESO Submission also noted that the decision on cost responsibility in the RES Proceedings was deferred until later in the proceeding after submissions by the parties.

AMPCO Submission

AMPCO filed its reply to the IESO Submission on October 29, 2019 (AMPCO Submission) in which it submitted, among other things, that in the two previous proceedings considering market rule amendments - the RES Proceeding and the Ramp Rate Proceeding - the OEB determined that the IESO should bear the costs of the proceeding. AMPCO noted that, in the Ramp Rate Proceeding, the OEB determined that it would not be appropriate to defer its decision on cost responsibility and made the same determination in the later RES Proceeding. The AMPCO Submission stated that, if the OEB defers determination of who should bear the costs of this proceeding, AMPCO would be forced to abandon the Application as it is not set up or funded to absorb the costs of a regulatory proceeding.

APPrO Submission

On October 29, 2019, APPrO filed its submission (APPrO Submission) in response to the IESO Submission. APPrO stated that deferring a decision on cost responsibility until after the determination of the Application would be unreasonable as APPrO (and other entities that have no ability to recover costs from ratepayers or market participants) would be exposed to uncertain cost risk, which will hamper its participation in this proceeding. APPrO also stated that deferring a decision on cost responsibility could discourage intervenors from seeking intervenor status to bring legitimate concerns and important perspectives to the OEB in other proceedings.

OEB Findings

The OEB has determined that the IESO shall bear the costs of this proceeding. The OEB remains of the view that this is consistent with the overall legislative scheme, which contemplates a review by the OEB as a potential last step in relation to market rule amendments.

The OEB acknowledges that the IESO is responsible for making and amending the market rules, but the fact remains that market rule amendments are subject to oversight by the OEB under section 33 of the Act (among others) and that this oversight is part of the legislative scheme even if as a proceeding separate from the IESO's market rule amendment process.

Based on the above, the OEB also does not see any compelling reasons to defer its decision on cost responsibility, as requested by the IESO.

Cost Award Eligibility

Submissions of the Parties

IESO Submission

The IESO objected to the cost award eligibility requests made by AMPCO, APPrO and KCLP on the basis that these parties are pursuing their own commercial interests and are *prima facie* not eligible for cost awards under the OEB's *Practice Direction on Cost Awards* (Practice Direction). Alternatively, the IESO requested that the OEB defer its decision on cost award eligibility until the end of the proceeding, as it had done in the RES Proceeding.

AMPCO Submission

In its submission, AMPCO referred to the Ramp Rate Proceeding where it was found eligible for recovery of its reasonably incurred costs on the basis that:

> (a) Its application raised legitimate issues for the OEB's consideration.
> (b) As market participants, members of AMPCO are in fact participating in the funding of cost awards in the matter through their payment of the IESO's administrative costs in accordance with the market rules.

The AMPCO Submission argued that the same is true of the Application.

The AMPCO Submission conceded that, in this Application, AMPCO is primarily acting in the interests of its members who offer, or who might offer, Demand Response resources, but noted that AMPCO is also advocating the interests of its members – including those who do not offer Demand Response resources – as electricity consumers. AMPCO submitted that the observations in the Ramp Rate Proceeding regarding AMPCO are instructive and analogous in respect of AMPCO's cost eligibility in this proceeding.

APPrO Submission

APPrO noted that it is a representative of generators who are directly impacted by this proceeding. APPrO submitted that it is uniquely positioned to provide the OEB with useful context as to how its members view the TCA, their ability to participate in it and other issues of asset utilization tied to the TCA. APPrO further stated that there are therefore special circumstances that warrant a finding that it should be afforded cost eligibility in accordance with section 3.07 of the Practice Direction.

SEC and KCLP

Two other intervenors also requested cost award eligibility in their Notices of Intervention – SEC and KCLP – although these two parties did not make submissions in response to PO 2 or the IESO Submission.

The IESO did not object to SEC's request for cost award eligibility.

In its Notice of Intervention, KCLP stated that if AMPCO is granted cost award eligibility, the OEB should do the same for KCLP in light of special circumstances under section 3.07 of the Practice Direction; namely, to ensure that one category of capacity resources (Demand Response resources) do not receive preferential treatment in this process over another competing category of capacity resources (electricity generators), given that both resources are direct competitors in the upcoming TCA.

OEB Findings

The OEB has determined that SEC, as a representative of ratepayers, is eligible for an award of costs under section 3.03 of the Practice Direction.

By contrast, all other parties requesting cost award eligibility are *prima facie* not eligible for an award of costs under section 3.05 of the Practice Direction, AMPCO by reason of being the applicant, and KCLP and APPrO by reason of being or representing, respectively, generators. However, section 3.07 of the Practice Direction contemplates that a party that falls into one of the categories listed in section 3.05 can be eligible in special circumstances.

The OEB has determined that AMPCO is eligible for an award of costs despite being the applicant. This is consistent with the OEB's view that the review process under section 33 of the Act is part of the overall market rule amendment process. The OEB also notes that, as market participants, members of AMPCO are participating in the funding of cost awards in this case through their payment of the IESO's fees in accordance with the market rules.

The OEB believes that, in this case, the views of generators with respect to the Amendments will be important to the OEB's determination of how the Amendments may fare relative to the criteria set out in section 33(9) of the Act. The OEB has therefore determined that APPrO is also eligible for an award of costs.

Although KCLP is also a generator, the OEB has determined that it is not eligible for an award of costs. The OEB is of the view that, given its broad membership, APPrO should be in a position to provide the OEB with generator perspectives on the Amendments, including the perspective of KCLP's owner Northland Power, which according to APPrO's website is a member of APPrO. Even if and to the extent that KCLP's current situation is different from the situation of other generators, it does not appear to the OEB based on KCLP's intervention letter that such difference translates to a unique perspective on the Amendments that speaks directly to the determinations to be made by the OEB on an application under section 33 of the Act.

Being eligible to apply for an award of costs is not a guarantee of recovery of any costs claimed. Cost awards are made by way of OEB order at the end of a hearing. Cost eligible parties should be aware that the OEB will not generally allow the recovery of costs for the attendance of more than one representative of any party, unless a compelling reason is provided when cost claims are filed.

The OEB also takes this opportunity to remind all of the parties that, as in all cases, parties are expected to act responsibly and that the OEB retains discretion to address irresponsible or inappropriate participation through the cost award process.

Parties should not engage in detailed exploration of items that do not appear to be relevant or material. In making its decision on costs, the OEB will consider whether parties made reasonable efforts to ensure that their participation in the hearing was focused on relevant and material issues.

DATED at Toronto, **November 12, 2019**

ONTARIO ENERGY BOARD

Original signed by

Christine E. Long
Registrar and Board Secretary

TAB 7

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2019-0206**	**Resolute FP Canada**

VOLUME:	**Issues Day**	
DATE:	**November 8, 2019**	
BEFORE:	**Emad Elsayed**	**Presiding Member**
	Cathy Spoel	**Member**
	Susan Frank	**Member**

to the panel. Any questions from the panel, Ms. Spoel?

MS. SPOEL: I have a couple of questions, Mr. Vegh. First of all, going back to your issues with respect to -- I guess your issue number 1, which is the context, you referred to the practice of the IESO and the practices in the market before and after the rule.

I am just wondering, you're talking about practice. How does that relate to the purpose which is what you have actually put in the words you have put into your proposed issue? Or is it really the same?

Is it part of determining what the purpose was, what the practice was before and what the practice was after?

MR. VEGH: Yes, yes. So when the courts refer to the mischief and legislative history, they say what was the pre-situation, what was the post-situation. And practice is, you know, that's what we are focussing in on. What was the impact.

MS. SPOEL: Thank you. My second question is related to your comments near the end about the review, and you referred to the ramp rate decision and the extent to which the OEB deferred to the IESO's process and all that.

My understanding that -- correct me if I'm wrong, because I would like your comments. But my understanding is a review under section 33, the OEB is required to approve any market rule before it actually comes into force. And people, parties can request a hearing if they object to the new rule.

So part of the rule amendment is our stamp of approval, because we review them all and approve them all, as far as I know. And if a party doesn't want us to approve it, they will say we'd like a hearing.

So the review of the IESO's process is kind of integral to that scheme because we actually have to approve it, whereas -- so if you can differentiate between that perhaps and section 35, where there is an existing rule that you want to have amended.

We wouldn't get involved in that, I think, unless you end up here, because if the IESO does review it and amend it -- well, I guess if they review it and amend it, we still have to approve that amendment.

MR. VEGH: I understand, yes.

MS. SPOEL: And then other parties, I suppose, could object, so you would get into another whole process here. But you are here under a different part of the legislative scheme, I think, because you are wanting us to order them.

The other difference under section 33 is we can't order them to change the amendment. We can only send it back to the IESO for further consideration. We don't have the same relief that we can offer.

MR. VEGH: Under 33?

MS. SPOEL: In 33. So I just wonder if, in your mind, does that make any -- does that distinguish how we would look at the IESO's review under section 35 compared to under section 33, which was where the ramp rate decision was?

If you want to think about this and, you know, answer

TAB 8

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

EB-2019-0206

Resolute FP Canada Inc.

Application by Resolute FP Canada Inc. for an order directing the Independent Electricity System Operator to amend the Market Rules relating to the qualifications for participating in Demand Response Auctions

DECISION ON ISSUES LIST AND PROCEDURAL ORDER NO. 2
December 6, 2019

On August 7, 2019, Resolute FP Canada Inc. (Resolute) applied to the Ontario Energy Board (OEB), pursuant to section 35 of the Electricity Act, 1998 (Act), for an order directing the Independent Electricity System Operator (IESO) to amend sections 18.2.1 and 19.2.1 of Chapter 7 of the IESO's Market Rules (DR Qualification Rules) (Application). These market rules address the qualifications for participating in the IESO's Demand Response Auctions. Resolute has also asked the OEB for direction on the production of documents and eligibility to recover its costs in respect of the Application. On August 13, 2019, Resolute filed additional materials in support of its Application.

Issues List

In Procedural Order No. 1 issued on October 22, 2019, the OEB noted that the parties had raised issues related to the scope of this proceeding and the OEB's jurisdiction in hearing the Application, and established a process for the development of an Issues List. Specifically, Resolute was directed to file a Draft Issues List, and provision was made for submissions on Resolute's Draft Issues List and subsequently for an Issues Day to be held on November 8, 2019.

Resolute filed a Draft Issues List on October 28, 2019. Submissions on that Draft Issues List were filed by the IESO and OEB staff, including their respective proposed issues lists. The issues lists proposed by each of Resolute, the IESO and OEB staff are reproduced in Schedule A.

Summary of the Positions of the Parties on the Issues List

Some of the positions evolved to some degree between the filing of written submissions and the Issues Day, and the summary below takes such evolution into account where applicable.

Resolute, the IESO and OEB staff each proposed: (i) two issues relating to the determinations to be made on an application under section 35 of the Act, as articulated in section 35(6); and (ii) one issue relating to how the OEB should exercise the remedial authority set out in section 35(6) of the Act in the event that the OEB determines that the DR Qualification Rules fail the tests that are also set out in that section.

There were variations in the wording proposed for these three issues, although during the Issues Day the IESO indicated that it was content to accept the wording proposed by OEB staff.

Resolute's Draft Issues List included an issue regarding the impact and effect of the DR Qualification Rules on Resolute and another regarding the purpose and context of the DR Qualification Rules. OEB staff's view was that the impact of the DR Qualification Rules on Resolute is already captured by the two issues referred to above relating to the determinations to be made on an application under section 35 of the Act. OEB staff was also of the view that the purpose and context of the DR Qualification Rules can be informative to the OEB, but to the extent that they are relevant they are also already captured and properly constrained within these same two issues. OEB staff therefore submitted that stand-alone issues were not needed as proposed by Resolute. At Issues Day, the IESO supported OEB staff's position.

Resolute's Draft Issues List and the issues list proposed by OEB staff both included a further issue going to the question of the relevance to this proceeding of the market rule review referred to in section 35(4) of the Act. Resolute noted that the IESO's review is a compulsory part of the review process as set out in legislation, and submitted that it must therefore have some meaning. Resolute further submitted that the requirement in section 35(4) is presumably for the purpose of providing the IESO with an opportunity to consider the matter, and is designed to assist the OEB in its review. Resolute also noted that parties can take different positions on the relevance of the review, and that debate should not be closed off now. At Issues Day, Resolute and the IESO agreed that consideration of the IESO review should not and does not imply that the OEB is obliged to defer to the IESO's decision; rather, they each acknowledged that the review may be informative to the OEB in this proceeding.

OEB staff submitted that the OEB's role in an application under section 35 is not to review the market rule review process engaged in for the purposes of section 35(4) of the Act in the sense of calling for an inquiry into the sufficiency or fairness of that process or an evaluation of whether the IESO reached the “correct” decision. However, OEB staff submitted that there was value in the OEB having before it the documentary record of the IESO’s review as it could be helpful to the OEB in making a determination as to whether the DR Qualification Rules fail the tests set out in section 35(6) of the Act. Similarly, the IESO submitted that an application under section 35 of the Act is not an appeal, review or oversight of the IESO’s process or decision, but agreed that it would be of assistance to the OEB and the parties for the record of the market rule review process to be placed before the OEB.

Findings on the Issues List

The OEB notes that there are three issues on which there appears to be no substantive disagreement. These are issues 4, 5 and 6 on Resolute’s Draft Issues List, issues 1, 2 and 3 on the IESO’s proposed issues list and issues 1, 2 and 3 on OEB staff’s proposed issues list. As noted above, at Issues Day the IESO indicated that it was content to accept OEB staff’s articulation of these three issues.

The OEB approves these three issues and adopts the following wording:

- Are the DR Qualification Rules inconsistent with the purposes of the *Electricity Act, 1998?*
- Do the DR Qualification Rules unjustly discriminate against Resolute?
- If the answer to either question 1 or 2 is yes, then how should the OEB direct the IESO to amend the DR Qualification Rules?

The OEB finds that adding the words “as applied” to the first two issues, as set out in the issues lists proposed by both Resolute and the IESO, is not necessary since the section 36(6) test inherently includes both “as written” and “as applied”.

Resolute’s proposed issues 1 and 2 concern the purpose and context of the DR Qualification Rules and their impact and effect on Resolute.

The OEB finds that issues 1 and 2 on Resolute’s Draft Issues List can be addressed under the first two approved issues listed above, and they therefore do not need to be separate items on the Issues List. The OEB finds that, while the history, context and application of the DR Qualification Rules is important to the OEB’s consideration of how they fare against the tests set out in section 35(6) of the Act, procedural details relating to the development of the DR Qualification Rules are not relevant to the determinations to be made by the OEB in this proceeding.

Issue 3 on Resolute's Draft Issues List and issue 4 on OEB staff's proposed list relate to section 35(4) of the Act, which makes it a condition precedent to the filing of an application under section 35 that the market participant have "made use of the provisions of the market rules relating to the review of the market rules". Essentially, the question is whether and how the IESO's review of the market rule amendment proposal made by Resolute for the purposes of section 35(4) of the Act is relevant to this proceeding.

The OEB finds that procedural details of the IESO's review of Resolute's market rule amendment proposal are not relevant to this proceeding, as this will not assist the OEB in reaching a decision on the Application. In this proceeding, the OEB cannot provide any relief relating to the IESO's review regardless of what those details might have been.

The OEB finds that the issue proposed by each of Resolute and OEB staff regarding section 35(4) of the Act does not need to be on the Issues List. However, the OEB is of the view that all materials that were before the IESO Technical Panel and Board of Directors relating to that review will assist the OEB in rendering its decision in this case. This Procedural Order provides for the filing of such materials by the IESO. At Issues Day, the IESO confirmed its agreement to file a record of the section 35(4) review similar in nature to the record that the IESO would be required to file in a proceeding under section 33 of the Act.

The approved Issues List for this proceeding is attached as Schedule B.

Cost Responsibility and Cost Award Eligibility

The issue of who bears the costs of this proceeding and who is eligible for cost awards is currently outstanding.

In its Application, Resolute asked that it be eligible to recover its costs of the Application, relying on cost decisions made in two earlier OEB proceedings under section 33 of the Act. An intervenor, the Association of Major Power Consumers in Ontario (AMPCO), has also requested cost award eligibility on the basis that it represents the direct interests of consumers in relation to services provided by the IESO.

In Procedural Order No. 1, it was noted that the OEB panel hearing the Application would make a determination on cost responsibility and cost award eligibility. Provision was, however, made for the filing of objections to the cost award eligibility requests of Resolute and AMPCO.

The IESO filed a letter on October 25, 2019 objecting to both requests for cost award eligibility. The IESO reiterated its earlier objection to Resolute's request on the grounds that, as an applicant, Resolute is presumptively ineligible for a cost award absent special circumstances under sections 3.05 and 3.07 of the OEB's *Practice Direction on Cost Awards* (Practice Direction). The IESO further submitted that Resolute has failed to demonstrate any special circumstances that would justify a departure from the general rule, and has failed to discharge the burden imposed under section 3.02 of the Practice Direction.

With respect to AMPCO, the IESO submitted that it is premature to determine whether AMPCO is participating in this proceeding primarily as a representative of ratepayers or is participating on behalf of its members' commercial self-interest. The IESO further submitted that, if the latter, this would weigh strongly against any entitlement with respect to costs.

The IESO requested the opportunity to make additional submissions on costs at a later stage in the proceeding.

The OEB considers it opportune at this time to make provision for submissions on cost responsibility and cost award eligibility.

Interrogatories and Type of Hearing

This Procedural Order makes provision for an interrogatory process.

By letter dated October 15, 2019, Resolute submitted that a written hearing may be sufficient, but reserved the right to request an oral hearing later in the process. The OEB will make its determination on the type of hearing once the interrogatory process is complete.

It is necessary to make provision for the following matters related to this proceeding. The OEB may issue further procedural orders from time to time.

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. The IESO is directed to file with the OEB, and deliver a copy to all parties, all of the materials that were before the IESO Technical Panel and Board of Directors related to the IESO's review of the amendment to the DR Qualification Rules proposed by Resolute for the purposes of section 35(4) of the Act, by **December 20, 2019**.

2. Any party or OEB staff that wishes to request any information and documentation with respect to the Application material filed by Resolute or the material filed by the IESO that is relevant to issues on the approved Issues List shall file written interrogatories with the OEB and serve them on all parties by **January 17, 2020**.

3. Resolute and the IESO shall file interrogatory responses with the OEB and serve them on all parties by **January 31, 2020**.

Submissions on Cost Responsibility and Cost Award Eligibility

4. If any party or OEB staff wishes to make a submission on which party should bear the costs of this proceeding or a submission objecting to the request of any party for cost award eligibility, it shall file a written submission with the OEB and serve it on all parties by **December 18, 2019**.

5. If any party or Board staff wishes to reply to a submission on cost responsibility filed by another party under paragraph 4, it shall file a written reply submission with the OEB and serve it on all parties by **January 8, 2020.**

6. If a party whose request for cost award eligibility is the subject of an objection by another party under paragraph 4, wishes to reply to the objection, it shall file a written reply submission with the OEB and serve it on all parties by **January 8, 2020.**

All materials filed with the OEB must quote the file number, **EB-2019-0206**, 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, **December 6, 2019**

ONTARIO ENERGY BOARD

Original signed by

Christine E. Long
Registrar and Board Secretary

Schedule A

Decision on Issues List and Procedural Order No. 2

Resolute FP Canada Inc.

EB-2019-0206

Draft Issues Lists Submitted By Parties and OEB Staff

December 6, 2019

DRAFT ISSUES LISTS SUBMITTED BY PARTIES AND OEB STAFF

Resolute's Proposed Issues List

1. What was the purpose and context of the Rules?
2. What was the impact and effect of the Rules on Resolute?
3. How should the Board take into account the review of the Amendment under s. 35(4) of the *Electricity Act, 1998*?
4. Are the Rules, as applied, consistent with the purposes of the *Electricity Act, 1998*?
5. Do the Rules, as applied, unjustly discriminate against Resolute?
6. Should the Board direct the IESO to amend the Rules, and if so, how?

The IESO's Proposed Issues List

1. Are the DR Eligibility Rules, as applied, inconsistent with the purposes of the *Electricity Act, 1998*?
2. Do the DR Eligibility Rules, as applied, unjustly discriminate against Resolute?
3. If the answer to either Question #1 or #2 above is "Yes", then how should the Board direct the IESO to amend the DR Eligibility Rules?

OEB Staff's Proposed Issues List

1 Are the DR Qualification Rules inconsistent with the purposes of the *Electricity Act, 1998*?

2. Do the DR Qualification Rules unjustly discriminate against Resolute?
3. In the event that the OEB finds that the DR Qualification Rules (i) unjustly discriminate against Resolute or (ii) are inconsistent with the purposes of the Act, in what manner and within what time should the OEB direct the IESO to amend the market rules?
4. Is the review of the DR Qualification Rules under section 35(4) of the Act relevant to the exercise of the OEB's mandate under section 35 of the Act beyond confirming that the review has in fact taken place? If so, how?

Schedule B

Decision on Issues List and Procedural Order No. 2

Resolute FP Canada Inc.

EB-2019-0206

Approved Issues List

December 6, 2019

Approved Issues List

1. Are the DR Qualification Rules inconsistent with the purposes of the *Electricity Act, 1998?*

2. Do the DR Qualification Rules unjustly discriminate against Resolute?

3. If the answer to either question 1 or 2 is yes, then how should the OEB direct the IESO to amend the DR Qualification Rules?

TAB 9

Ontario

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2019-0242**	**AMPCO Motion**
VOLUME:	**1**	
DATE:	**November 25, 2019**	
BEFORE:	**Cathy Spoel**	**Presiding Member**
	Emad Elsayed	**Member**
	Susan Frank	**Member**

the otherwise DRA, demand response auction, when it becomes a transitional capacity auction.

That is the whole issue at play here today, is the issue of the discriminatory nature of the amendments. That is why I included it in my affidavit. That is why I understood that the IESO would understand it. And I hope that clarifies what it was that I was trying to state.

MR. MONDROW: Thank you, Mr. Anderson. I am going to just identify for you, again, Exhibit K1.1, which was the letter dated November 22nd, 2019, the CV which you have already spoken to, and a one-page witness statement which we provided, Madam Chair, to parties in advance just so they would have an indication of two issues connected to Dr. Rivard's evidence that Mr. Anderson wished to address in his direct testimony. And so that is why I identify that and filed it.

Mr. Anderson, just to those two issues, in his evidence Dr. Rivard goes through a number of scenarios involving a demand response resource consisting of a behind-the-meter generation facility which allows the load customer to displace a portion of its own demand for energy from the market, and Dr. Rivard compares that facility to a load customer who is also a directly connected generator, market participant.

And you wanted to address the aptness of that comparison in Dr. Rivard's evidence.

MR. ANDERSON: I did, thank you. Dr. Rivard's example is very specific. He uses an example of a demand response resource with a behind-the-meter generator, so in that case when activated the demand response resource simply ramps up its generator.

This is, by far, the minority example of what actually happens in a demand response activation. Typical demand resources don't have behind-the-meter generators. The majority of them do not.

And what they do, in terms of responding to activation notices, is they dial back their processes. They shut down equipment. They stop making whatever widgets that they would rather be making.

These operations incur real costs to do this, beyond the cost of lost production, as highlighted by Dr. Rivard. And I will give you some examples of this. I will take the steel industry as an example, because it is probably easier to understand than some of the others.

In a situation where demand response is activated, typically steel manufacturing entities would take out of service called an electric arc furnace. If that electric arc furnace happens to still have molten steel inside it, you're no longer putting electricity to it to keep it that way. It will eventually harden up. That is a very bad thing. So they do fire on gas.

In addition to that, there's a downstream process where billets are loaded into a furnace for further processing. Those furnaces are full of refractory, which is basically industrial grade insulation, for lack of a better term.

That refractory, if it is subjected to temperature fluctuations, will crack, break, and fall off. It is very expensive. So they also have to fire that furnace with natural gas, which they otherwise would not have to do. These are costs that are avoidable in a situation where they have been told to activate.

Another example -- and again it is a gas-firing example -- steel melts at somewhere around 2,500 degrees Fahrenheit. Generally speaking, the facilities that make steel don't have building heating. They don't need it. But in a situation in the middle of winter where you have shut down and stopped your process, it starts to get cold, and things inside that facility can freeze up, and they do have to bring in gas-fired heaters to keep that facility warm. Again, another situation where, but for the activation, you wouldn't be burning that gas and you wouldn't be incurring that cost.

So for those customers there is a much broader range of costs beyond the value of the lost load and a broader range of risks to consider.

And I think one final point that Dr. Rivard makes is an implication based on -- I think it is based on some of his other studies from other jurisdictions that you can simply shift that production, you can make those widgets later. And some DR resources can actually do that. Many cannot. When you lose the production of those widgets, you lose it for good. You don't just shift it into the off-shift, because you don't have that spare capacity. And I

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO)

Response to Staff #1

Reference: AMPCO Application, Paragraph 22 (page 6); Affidavit of Colin Anderson, page 4, para. 15, 17.

Preamble:

AMPCO's application states that under the Transitional Capacity Auction (TCA) rules generators will offer into the auction at prices that take into account their anticipated energy payments. DR resources will have to compete against these bids without an equivalent energy payment stream, putting DR resources at a competitive disadvantage to generators in the capacity market.

The Affidavit refers to an IESO proposed "work-around" that has sometimes been used.

> In that "work-around" DR resources have increased their capacity offers by an amount sometimes referred to as a "utilization payment". This "utilization payment" is thought of as a partial proxy for energy payments upon activation. Inclusion of this proxy allows the DR Resources to offer a price that would provide them with some compensation if they are activated for energy. If this proxy methodology were to be used by DR Resources in the TCA it would increase their offers and make them uncompetitive relative to generators.

The Affidavit also states "Those participants who include "utilization payments" in their capacity offers (DR Resources) are unlikely to clear the capacity market since they will be including cost elements that other participants (generators) will not be including, because those other participants will cover those costs in their energy payments that they will receive when activated."

Questions:

(a) Please provide a detailed list of the cost elements or cost categories that DR Resources include in their capacity offer prices for the Demand Response Auction (DRA). Please also provide an approximate percentage value that each element would account for in the total auction offer price. Please respond for a typical dispatchable load Demand Response Auction Participant (DRAP), and a typical Hourly Demand Response (HDR) resource DRAP.

(b) Does the above-mentioned utilization payment proxy sometimes used by DR Resources also relate to costs of being activated? If so, please identify what these costs are. Please also identify, for a typical dispatchable load and HDR participant, an approximate breakdown of these costs and all other elements that form part of these participants' Demand Response Energy Bids.

(c) Please explain the circumstances under which the partial proxy "work-around" is used, and the circumstances under which it is not used.

(d) To what degree does the "work-around" reflect a capitalization of energy market costs borne by demand responders with DRA capacity obligations into their offer prices for the DRA? Are these costs always present for a demand responder with a DRA capacity obligation, or are they only present when the demand responder is activated?

(e) A dispatchable load with a commitment in the DRA must make Demand Response Energy Bids into the Day Ahead Commitment Process (DACP) and the real time energy market (RTEM), and these bids must cover all hours in its availability window. A dispatchable load that does not have a commitment from the DRA may enter bids in DACP and the RTEM if it wants to consume energy. If these two dispatchable loads are in all other respects the same, please:

i. explain how their energy bids into the DACP and the RTEM would be different. In providing this explanation please identify all significant elements that comprise the energy price bid for a given quantity of energy demanded.

ii. Identify any other differences in the situation of a dispatchable load with a commitment from the DRA and one without.

iii. Explain whether and how these differences will cause the behaviour of these two participants to differ.

Response:

(a) A Demand Response Auction Participant (DRAP), when determining its bid parameters ($/MW and Quantity of MW) for the DRA/TCA, needs to consider both the cost of providing the availability, as well as the potential costs associated with curtailment when asked to do so in the real time energy market. This second set of costs requires a DRAP to make an estimate of the number of activations they may experience.

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. Accordingly, AMPCO is not in a position to provide an approximate percentage value that each element would account for in the total auction price and that would be reflective of the cost elements of a class of resources.

Factors that may be considered in determining capacity auction offers include:

1. <u>Cost per Curtailment</u>:

    - Lost opportunity
        - Forecast production schedule and flexibility (i.e. is the plant's output completely sold out, or can lost production be made up later?)
        - Product type being made at the time
        - Product margins at the time
        - Product energy intensity
        - Foreign exchange rates
        - Business Reputation Risk (i.e. will curtailments affect the DR resource's high value customers, thereby damaging DR resource's reputation, future business opportunities, prices, etc.?)
        - Inventory Costs

    - Semi-variable cost recovery
        - Labour costs
        - Other Overhead costs for production facility

2. <u>Number of Curtailments</u>:

    - Entity's Risk Tolerance (could change seasonally or could be variable depending on market conditions)

    - Weather Impact (Frequency of activations)
        - Winter Forecast
        - Summer Forecast
        - Unusual weather events (e.g. polar vortex)

    - Length of Curtailment Risk
        - HDR risk is between 1 to 4 hours of curtailment
        - DL could be 5 minute to full availability window (9 hrs)
        - Curtailment costs increase as duration increases

- Natural Gas/power price forecast

- Market Price Risk (i.e. the potential for changes in the electricity market supply that could have impacts on price)

3. <u>Other Considerations</u>:

- Availability Risk
    - Possibility of penalties

- Administration costs
    - Contract management
    - Metering
    - Daily Bidding

- Individual Department risk
    - Energy Intensity of upstream and downstream operations that are impacted
    - Equipment wear and tear

- Shut down/Start up risk (for all impacted equipment)

(b) Yes, the above-mentioned utilization payment proxy sometimes used by DR Resources also relates to costs of being activated. See part a) for a listing of potential costs.

In the DRA, participants can only recover their costs in their auction offer, while assuming the risk that they may be activated for more hours than they have forecast.

The costs above refer to a typical Dispatchable Load ("DL") or an Hourly Demand Response Resource ("HDR"). The difference to consider is DL's may be activated for as short a period as 5 minutes or as long as 9 hours with no limit on the number of activations per day, whereas HDR activations are currently 4 hours in length (and could be as short as 1 hour), and they can only be activated once per day.

(c) As set out in AMPCO's evidence (Affidavit of Colin Anderson, paragraphs 15-20) DR resources may or may not incorporate utilization amounts in their capacity offers.

The circumstances in which a specific resource will incorporate these elements are driven primarily by the entity's risk tolerance, and its perspective on activation probabilities. For example, a DR resource that feels it will likely be activated will probably include utilization amounts in its capacity offers. A resource that feels the probability of activation is very low may not incorporate such elements.

The decision on whether to include or not is entity specific and driven by its approach to offers and one or more of the various factors listed in response to part (a) and any other factors or considerations relevant for that entity.

(d) Costs associated with curtailments typically increase the entity's operating, maintenance and administration (OM&A) costs and are therefore not typically capitalized. Capital costs would generally be included by DR resources in their capacity offers exclusive of any "utilization payment" proxy workaround.

(e) In general, any individual load is going to have the same approach to offering, unless its costs change between the two different timeframes (DACP vs real time (RT)). For example, a load facility's production schedule could (theoretically) change between the DACP and RT time horizons, which could fundamentally change the entity's desire to consume – which would manifest itself in different offers between the two time horizons.

In regards to a DR resource that has a DRA position versus one that does not, offer strategy is participant specific. It is possible that, all other things being equal, the entity with the DRA position could have a lower bid, but this is not necessarily the case since no two participants have identical cost profiles.

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2019-0242**	**AMPCO Motion**

VOLUME:	**1**	
DATE:	**November 25, 2019**	
BEFORE:	**Cathy Spoel**	**Presiding Member**
	Emad Elsayed	**Member**
	Susan Frank	**Member**

Ontario context.

But, yes, I think that would be an appropriate place to start.

MS. KRAJEWSKA: Mr. Anderson, I am going to take you back to tab F of your cross-examination compendium, which is your response to the interrogatories from Staff.

The list of factors, do they represent the variable costs of your membership? Do they represent the marginal cost of your membership in putting in the offer price? I mean, what do they represent in economic terms?

MR. ANDERSON: Yes, I am going to put my hand up right now and say I am not an economist. But what we're looking at here in terms of the cost per curtailment, there is a large category of lost opportunity cost. And then what it is framed as is semi-variable cost recovery. I would say that is variable costs, and that includes labour costs, other overhead, and really other costs for the production facility -- the gas firing that I talked about, for example, in the electric arc furnace or in the reheat furnace would fit in that category.

MS. KRAJEWSKA: And if you --

MR. ANDERSON: Sorry, I just want to finish and give a complete answer.

If you turn the page to number 3, I guess it is, the other consideration, it talks about administrative costs and that's administrative costs of actually doing the DR business.

It also talks about shut down and start up risk and there are costs associated with that. Wear and tear on equipment is a very real cost, and the other thing to think about is in a number of these process-oriented facilities, when start up and shut down, you've gone outside your quality boundaries for a period of time.

So you are wasting, whether it is pulp and paper or whether it is steel, or whatever the widget is that comes out the back end of that facility, you have wasted a chunk of it. So those are very real costs.

MS. KRAJEWSKA: But in each of those circumstances, the DR resource would factor that cost into their bid price, correct?

MR. ANDERSON: Each resource would factor it in in the way it saw as appropriate.

MS. KRAJEWSKA: Mr. Anderson, I would like to -- in your witness statement, you take issue with Mr. Rivard's evidence with respect to his models that look at DR resources that have a behind-the-meter generator. That's correct?

MR. ANDERSON: Yes, that's correct.

MS. KRAJEWSKA: And, Mr. Anderson, you have not filed any evidence with respect to how many of your members have behind-the-meter generators.

MR. ANDERSON: I have not, no. But as I said in my -- I believe in my direct, those who have behind-the-meter generation are in the far minority to those who do not.

MS. KRAJEWSKA: But that information is also - how many, or which demand response resources or consumers of

Demand Response Working Group Meeting Materials

Demand Response Working Group

June 19, 2019

Meeting Agenda

Time	Agenda Item
9:00am	Welcome
9:05am	DRWG Update
9:10am	Presentation - Revised DRWG 2019 Work Plan
9:40am	Presentation & Discussion - Capacity Obligation Transfer in the TCA
10:00am	Presentation – HDR Resource Testing Results
10:15am	Presentation & Discussion – HDR Resource Testing Proposal
10:35am	Break
10:50am	Presentation & Discussion – Cost Recovery for Out-of-Market Activation Payments - HDR Resources Proposal
11:40am	Presentation & Discussion - Energy Payments for Economic Activation of Demand Response Resources Research Plan
12:10pm	Wrap-Up & Next Steps
12:20pm	Adjourn

ieso Connecting Today. Powering Tomorrow.

Cost Recovery for Out-of-Market Activation of Hourly DR Resources - Proposal

Demand Response Working Group

June 19, 2019

Connecting Today.
Powering Tomorrow.

Purpose

- Discuss a proposal to provide HDR resources cost recovery for out-of-market activations (i.e. testing or emergency activations) consistent with treatment of other resource types

HDR Activations

- There are two ways an HDR resource can be activated

In-Market

- Based on market economics
- HDR energy bids intended to reflect the maximum they are willing to consume at given price
- HDR will be “activated” when the price for electricity is greater than their willingness to consume

Out of Market

- HDR resources can be activated outside of market economics to respond to a:
  1. Capacity test, or
  2. Emergency Control Action
- HDR will be activated even if the electricity price is lower than their bid price

- Observed bid prices and stakeholder feedback indicate that activation costs (explicit and opportunity) can be significant for HDR resources

Out Of Market Costs

- When other resource types (dispatchable load, generator, import) are dispatched out-of-market they are eligible for some form of "make-whole-payment"
  - A make-whole payment may apply when a participant faces a shortfall between their resource bid/offer price and the revenue earned through market clearing prices
  - The payment restores the participant to the financial situation they would have been in as implied by their bids/offers
- HDR resources do not receive a make-whole payment for out of market activations
- These costs may be reflected in their capacity offers potentially increasing the cost of the capacity

Implications for ICA and TCA Participation

- In the Demand Response Auction, HDR participants could reflect the expected cost of out-of-market activations in DR Auction offer prices
  - Since the DR Auction was for <u>DR only</u>, all HDR resources were impacted equally
- In the context of the proposed capacity auctions, where HDR will be competing against other resource types, how these costs are recovered will potentially impact market efficiency

Proposal

- IESO's initial assessment concludes that providing HDR resources cost recovery for out-of-market activations is:
  - appropriate as testing or emergency activations can occur at a price below bid price of an HDR
  - consistent with energy market and existing design treatment of other resources (including dispatchable load)

Potential Design Considerations/Issues

IESO requests feedback from stakeholders on potential design considerations, including:

- Most appropriate method for determining compensation; for example:
  - Using energy bids as representative costs
  - Historical precedents, such as CBDR activation payments
  - Identify costs on individual or type of resource basis
- Undue administrative burden of potential options
- Operational impacts on market participants, for example measurement data requirements
- Other considerations that should be assessed

Next Steps/Timelines

- Stakeholders to provide feedback on concept and design considerations by July 5
- Work with stakeholders on design details of this concept and initiate market rule amendment process during Q3, 2019
- Timeline
  - Implement changes for May 2020 TCA obligation period to enable DR participants to incorporate change to offers in December TCA

Demand response programs in selected US markets

prepared for the Ontario Energy Board staff by London Economics International LLC ("LEI")

November 8th, 2019

Federal Energy Regulatory Commission ("FERC") Order 745 established that demand response resources participating in organized wholesale energy markets (day-ahead and real-time) would be compensated through the payment of the locational marginal price for curtailing their load if dispatched. However, Order 745 did not directly impact the majority of demand response resources participating in programs administered by the two US Independent System Operators ("ISO") and one Regional Transmission Organization ("RTO") that LEI reviewed, as these demand-side resources tended to serve more as capacity providers. Demand response resources as capacity providers make up the majority of demand-side participation in the ISO and RTO programs that LEI reviewed, and capacity payments make up the bulk of their total compensation (although additional payments are made if these resources are actually activated). In contrast, the total dispatch of demand response resources through ISO and RTO programs reviewed by LEI was low, as were revenues associated with dispatch.

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Symbiotic nature of energy and capacity payments

Theoretically, a market participant's bid into the capacity market will reflect the residual revenue need that is required after all other sources of revenue or cost reductions have been considered. In the case of load, there are two potential 'revenue' sources: payments, if allowed, at LMP or some other level when dispatched, and the cost avoided by not operating. Note that failure to operate is not "free"; the cost to load of not operating in the period is equal to its lost profit for the period when it has been dispatched plus any shut down and restart costs. In a functioning market, the capacity payment would be expected to equal the desired revenue minus expected activation payments (at LMP or some other level) minus expected avoided costs. Allowing for an activation payment would not necessarily increase consumer costs; rather, it would shift the means by which they are paid out, and delineate between the "reservation payment" embodied in the capacity payment and the "utilization payment" embedded in the activation payment.

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ONTARIO ENERGY BOARD

FILE NO.:	**EB-2019-0242**	**AMPCO Motion**

VOLUME:	**1**	
DATE:	**November 25, 2019**	
BEFORE:	**Cathy Spoel**	**Presiding Member**
	Emad Elsayed	**Member**
	Susan Frank	**Member**

relevant respects?

And when we look at the product that is being provided, in theory, if the market rules have been written appropriately, the product should be the same.

Now, when we start thinking about this question of whether there are short-run marginal costs that arise from participating in DR markets, I think that we need to bear in mind the diversity of market participants and the fact that being activated for many is not frictionless. It is not as simple as flipping a switch and bearing no cost in doing so.

And so when we talk about a more nuanced approach, we believe that it is important to explore whether there are actually short-run avoidable costs that are incurred by DR providers, and we believe that if we are going to apply the concept of horizontal equity, that those short-run costs should be recovered.

So this is where we distinguish ourselves a bit from Dr. Rivard's evidence.

MS. DJURDJEVIC: One more question on these IRs, and this is your response to KCLP's interrogatory response 4A, where you respond that -- and I am skipping to the second sentence:

"With regards to economic efficiency, LEI's concern is with regards to the fidelity of the price signal and the need for a more nuanced approach."

Can you explain your reference to price signal, and of my questions.

MS. SPOEL: Thank you, Mr. Barz.

Mr. Mondrow.

MR. MONDROW: Thank you, Madam Chair. I do have a few questions.

MS. SPOEL: Great.

CROSS-EXAMINATION BY MR. MONDROW:

MR. MONDROW: Good afternoon, gentlemen. Mr. Goulding, I can refer you if you wish to page 31 of your report. In Staff's compendium it has come out as page 60 of 86. It might be easier to find it there.

And I just -- you mentioned off the top I think in your direct examination some of your primary or basic conclusions.

Am I correct that one of your conclusions is that there is a strong practical linkage between capacity market participation by DR resources and activation payments?

MR. GOULDING: I would like to recharacterize that a bit if I could, which is, first of all, resources are not going to participate in any form if they don't perceive it to be remunerative.

And the part of what they're seeking compensation for is the risk of being activated and the costs that will be incurred.

So when we look at the market rules specific to the capacity mechanism and the energy market, the market rules need to enable the DR participant to recover the total of their need across the multiple product streams.

TAB 10

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2019-0242**	**AMPCO Motion**

VOLUME:	**1**	
DATE:	**November 25, 2019**	
BEFORE:	**Cathy Spoel**	**Presiding Member**
	Emad Elsayed	**Member**
	Susan Frank	**Member**

context for the provision of that information, please?

MR. ANDERSON: Yes, I can. AMPCO has been directly engaged in the Demand Response Working Group and all the stakeholdering associated with that since March 2019.

I have personally attended most, if not all of the stakeholder sessions. Many times I am there with members right beside me; other times I am there just myself.

As far as I am aware, the IESO has received all of the submissions that I have offered as input from AMPCO.

Those submissions have been informed and created by numerous conversations with my members and my board of directors.

And to be very clear, AMPCO's expressed opinions are validated by its board of directors. And every single one of those submissions that were filed by AMPCO was reviewed by my board of directors in advance, and they had adopted it and agreed with the content and agreed with my filing it.

MR. MONDROW: Thank you, Mr. Anderson. I would like to take you to paragraph 15 of your affidavit, please.

MR. ANDERSON: Okay.

MR. MONDROW: And at paragraph 15, you say:

> "In the existing DRA process, an IESO proposed workaround has sometimes been used. In that workaround, DR resources have increased their capacity offers by an amount sometimes referred to as a utilization payment. This utilization payment is thought of as a partial proxy for

energy payments upon activation. Inclusion of
this proxy allows the DR resources to offer a
price that would provide them with some
compensation if they are activated for energy."

Now, the IESO has filed evidence, and in paragraph 99 of its evidence, it says it does not know what you are referring to. And I understand you would like to address this IESO response and clarify the issue which you were addressing in the evidence excerpt that I just read into the record.

MR. ANDERSON: I would, thank you. The specific paragraph in the IESO's evidence is paragraph 99, and it implies that it doesn't seem to understand the point that I was making in my affidavit in respect of utilization payments. So I would like to try to clarify that.

I would like to start with the April 24th, 2019, SAC meeting, which I believe we have copies of and if we could put that up and pull up -- I think it is page 6, that would be helpful.

MS. DJURDJEVIC: We will make that Exhibit K1.3.

EXHIBIT NO. K1.3: DOCUMENT ENTITLED STAKEHOLDER ADVISORY COMMITTEE (SAC) MEETING MINUTES DATED APRIL 24TH, 2019

MR. MONDROW: Thank you. Mr. Anderson if you could just identify the document for the record, and explain what this is.

MR. ANDERSON: For the record, this is the minutes from the April 24th, 2019, SAC meeting.

MR. MONDROW: And SAC stands for?

MR. ANDERSON: Sorry, Stakeholder Advisory Committee. I am going to apologize in advance for the number of acronyms. I will slip up, and you have my apologies, and please capture me and get me to clarify.

MR. MONDROW: This is a committee of the IESO?

MR. ANDERSON: It is, major stakeholders providing -- and the IESO can certainly correct me on this -- but providing policy level advice to the IESO senior management and the IESO board of directors.

MR. MONDROW: Thank you. So that is Exhibit K1.3, and you wanted to take us to a reference in there?

MR. ANDERSON: Is it -- can it come up or should it come up? Did it come up? There it is.

For the record, the point that I wanted to refer to is in the comments section. So if we could scroll down to that main paragraph at the bottom half of the page, that would be helpful. Perfect. That is perfect.

MR. MONDROW: This is page number 6, as you can see at the lower left-hand corner.

MR. ANDERSON: It is, thank you for that. As I said, this is the minutes from the April 24th, 2019, SAC meeting, a meeting at which I was in attendance.

So I am going to read from this paragraph, starting somewhere around the middle of the paragraph and it starts with the words "Ms. Ingram".

"Ms. Ingram said that DR resources do not receive energy payments when their capacity is delivered under the DR auction, and have been consistently advised by the IESO, since the inception of the DR auction, that this should be reflected in their auction bid prices. She further noted that under the TCA design, dispatchable fossil fuel generators will receive energy payments for providing capacity, and thus do not have to build this into their auction bid prices, and that this is discretionary to DR participants. Mr. Short said a conversation about this will take place within the Demand Response Working Group."

Now, I was at that meeting. I remember Ms. Ingram's expression of this sentiment. I have actually been told the same thing by a number of my own members and to be clear, I recognize that these minutes don't necessarily highlight the correctness or incorrectness of any given statement. But nobody at that meeting, to my recollection, called Ms. Ingram and said this is incorrect.

So we have Ms. Ingram, we have the other AMPCO members, and we have the statements that I made in respect of my affidavit dealing with utilization payments.

So whether or not the IESO officially advised the DR -- sorry, officially DR resources to do this is not the point. Clearly the IESO and IESO staff were aware that this was something that took place, and had taken place for a number of years.

The point, the real point of this is that such a mechanism no longer works once generators are allowed into the otherwise DRA, demand response auction, when it becomes a transitional capacity auction.

That is the whole issue at play here today, is the issue of the discriminatory nature of the amendments. That is why I included it in my affidavit. That is why I understood that the IESO would understand it. And I hope that clarifies what it was that I was trying to state.

MR. MONDROW: Thank you, Mr. Anderson. I am going to just identify for you, again, Exhibit K1.1, which was the letter dated November 22nd, 2019, the CV which you have already spoken to, and a one-page witness statement which we provided, Madam Chair, to parties in advance just so they would have an indication of two issues connected to Dr. Rivard's evidence that Mr. Anderson wished to address in his direct testimony. And so that is why I identify that and filed it.

Mr. Anderson, just to those two issues, in his evidence Dr. Rivard goes through a number of scenarios involving a demand response resource consisting of a behind-the-meter generation facility which allows the load customer to displace a portion of its own demand for energy from the market, and Dr. Rivard compares that facility to a load customer who is also a directly connected generator, market participant.

And you wanted to address the aptness of that comparison in Dr. Rivard's evidence.

MR. ANDERSON: I did, thank you. Dr. Rivard's example is very specific. He uses an example of a demand response

IESO Stakeholder Advisory Committee Meeting Notes – April 24, 2019

Advisory Committee Members:
Mr. Brian Bentz (representing Distributors and Transmitters)
Mr. Nicolas Bossé (representing Energy Related Businesses and Services)
Mr. David Butters (representing Generators)
Ms. Judy Dezell (representing Ontario Communities)
Ms. Brandy Giannetta (representing Generators)
Ms. Malini Giridhar (representing Energy Related Businesses and Services)
Ms. Julie Girvan (representing Consumers)
Mr. Jim Hogan (representing Distributors and Transmitters)
Ms. Rachel Ingram (representing Energy Related Businesses and Services)
Mr. Bruno Jesus (representing Transmitters and Distributors)
Mr. Frank Kallonen (representing Distributors and Transmitters)
Mr. Paul Norris (representing Generators)
Mr. Mark Passi (representing Consumers)
Mr. Mark Schembri (representing Consumers)
Mr. James Scongack, Vice Chair (representing Generators)
Mr. Hari Suthan (representing Energy Related Businesses and Services)
Mr. Terry Young (representing IESO)
Regrets:
Mr. Pat Chilton (representing Ontario Communities)

IESO Board Members:
Mr. Simon Chapelle
Ms. Cynthia Chaplin
Mr. Peter Gregg
Ms. Margaret Kelch
Mr. Joe Oliver
Ms. Deborah Whale

Presentations:
Mr. Terry Young
Mr. David Short
Mr. Leonard Kula
Ms. Barbara Ellard

April 29, 2019
Please report any comments by email to engagement@ieso.ca

Ms. Jessica Savage
Ms. Alexandra Campbell
Mr. Emanuel Movchovitch

Meeting materials can be accessed online at www.ieso.ca/sac

Agenda Item 1. Welcome Remarks

Mr. Peter Gregg welcomed returning IESO board members and announced two members: Mr. Joe Oliver is former federal Minister of Finance, former federal Minister of Natural Resources, past president of the Investment Dealers Association, and past executive director of the Ontario Securities Commission.
Mr. Simon Chapelle is an elected member of Kingston City Council, former board member of Kingston Hydro, and former board member of the Parole Board of Canada.

Mr. Bentz welcomed three new SAC members:
Mr. Bruno Jesus, director of strategy and integrated planning, Hydro One Networks Inc., Ms. Malini Giridhar, vice president, business development and regulatory affairs, Enbridge Gas Inc.; and,
Mr. Pat Chilton, CEO, Five Nations Energy Inc.
Mr. Ted Leonard has resigned from the SAC. A call for nominations was published in March to fill the vacancy.

Mr. Terry Young introduced members of the IESO executive team in attendance: Leonard Kula, Robin Riddell, Alex Foord, Glenn McDonald, and Julia McNally.

Agenda Item 2. IESO Business Update Items – Memoranda and Discussion
Mr. Terry Young

Mr. Young provided the following business updates:

The annual Electricity Summit will take place on June 17, bringing sector leaders together from across North America. The theme of this year's Summit is Electricity Marketplace of the Future.

A series of four Regional Electricity Forums concluded in April. A report will be produced to summarize the input from the meetings held in Kitchener, Kingston, Timmins, and Thunder Bay.

Engagement is under way to seek input into the development of Integrated Regional Resource Plans (IRRPs) across Ontario.

Young replied that the IESO would look at how LDCs can be made aware of local customer engagement.

Mr. Bentz noted that the Conservation First Framework looked at efficiency in terms of kilowatt-hours. It would be helpful to LDCs if they could see the benefits coming out of conservation programs. Those benefits could potentially be auctioned and procured. Mr. Young said that as the system is decentralized, exploring non-wire alternatives would have its challenges but that the IESO is exploring these opportunities with a pilot in the York Region.

Mr. Passi asked if various levels of funding would be available for adoption of innovation projects within the context of the previous Industrial Accelerator Program (IAP). The timing and backlog of programs has been frustrating. Mr. Young said a highlight of the previous IAP program was the ability to fund innovation by working with customers; much ratepayer money went into it. With the transition of the new interim framework the IESO will be working with large industrials to see how they can address these needs.

Ms. Girvan asked if the reduced budget of $353 million to deliver the interim framework represents the entire reduction. Mr. Young said the entire reduction would be $445 million. Conservation energy savings are expected to be close to the previously set target.

Ms. Dezell said municipalities are drivers of conservation and would like as much information as possible to be shared. Mr. Young agreed, stating the municipalities are now being made aware of opportunities for water and wastewater treatment plants.

Mr. Hari Suthan said funding allocated within the interim framework and GIF could transform how customers want the sector to evolve.

Mr. Bruno Jesus asked why loss reductions are absent within CDM programs. Mr. Young said he was unsure.

<u>Comments from the Floor</u>

Mr. Andrew Teliszewsky from OPUS One Solutions asked for clarification on the $445 million reduction. Mr. Young said there would be less expenditure with the new CDM plan being put forward. Mr. Teliszewsky asked if this would change demand projections. Mr. Young replied that it would be factored in the demand forecasting.

<u>Agenda Item 4. Meeting Capacity Needs for 2020 and Beyond</u>
Mr. David Short

Mr. Short said the Transitional Capacity Auction engagement kicked off on March 7 when the IESO received stakeholder feedback. The DR auction will be expanded in Q4 2019 to incorporate off-contract, dispatchable generation as Ontario transitions from a period of surplus to one of significant need in 2023.

In response to stakeholder feedback, the IESO is reducing the scope of Phase 1 to allow sufficient time for stakeholder input. There have been two engagement sessions so far and more will take place in May when the market rules are presented for review. There may be an education session available for the Technical Panel as well.

Stakeholders identified a need to remove barriers to competitive participation by DR resources in the energy and ancillary services markets. If there is a high level of consensus the TCA will address this in the auction.

Target capacity will be adjusted where necessary to maximize participation and competition.

A session was held on April 18 on design features that were published on April 11. Loads receiving payment for energy dispatch was identified as a concern, as well as an opportunity for energy payments. Within the TCA, participants will have to incorporate start-up costs associated with energy payments. The Demand Response Working Group (DRWG) will discuss these subjects.

Comments

Ms. Rachel Ingram noted DR aggregators remain concerned about the ability to receive energy payments for loads. She commented that DR aggregators support expanding Ontario's procurement of capacity products to additional resources in a manner that provides a level playing field for all resources while ensuring efficient and fair competition, and added that for several years, many of her constituents, have been urging the IESO through the DRWG and the TCA and ICA stakeholder engagements to remove the barriers that prohibit DR resources, including those comprised of aggregated load, to participate in the energy, ancillary and OR markets prior to the first ICA. Ms. Ingram said that DR resources do not receive energy payments when their capacity is delivered under the DR Auction and have been consistently advised by the IESO since the inception of the DR Auction that this should be reflected in their auction bid prices. She further noted that under the TCA design, dispatchable fossil-fueled generators will receive energy payments for providing capacity and thus do not have to build this into their auction bid prices, and that this is discriminatory to DR participants. Mr. Short said a conversation about this will take place within the DRWG. Energy payments within the TCA will not be easy to resolve, but the goal is to ensure there is benefit for Ontarians. Ms. Ingram suggested slowing the process down in order to properly stakeholder the issue. Observing that there is no immediate need for additional capacity required in 2020, she

IESO Technical Panel Meeting

Minutes of Meeting

Date held: August 13, 2019	**Time held:** 9:00 am	**Location held:** IESO Office, Toronto

Invited/Attended	**Sector Representation**	**Attended; Regrets**
Robert Bieler	Consumer	Present
David Brown	Ontario Energy Board	Present
Ron Collins	Energy Related Businesses and Services	Present
Dave Forsyth	Consumer	Present
Sarah Griffiths	Other Market Participant	Present
Robert Lake	Residential Consumer	Present
Phil Lasek	Industrial Consumer	Present
Robert Reinmuller	Transmitter	*Absent*
Sushil Samant	Generator	Present
Joe Saunders	Distributor	Present
Jessica Savage	IESO	Present
Vlad Urukov	Generator	Present
Julien Wu	Wholesaler	Present
Michael Lyle	Chair	Present
Observers / Presenters		
Adam Cumming	IESO	Present
Mohab Elnashar	IESO	Present
Robert Doyle	IESO	Present
Silviu Motoc	IESO	Present
David Short	IESO	Present
Jessica Tang	IESO	Present
Candice Trickey	IESO	Present
James Hunter	IESO	Present

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

Secretariat		
Reena Goyal	IESO	Present
Jason Grbavac	IESO	Present
Prepared by: Mitchell Beer / Smarter Shift Inc.		

Agenda Item 1: Introduction and Administration

Chair's Remarks:

The Chair indicated that Robert Reinmuller would not be attending the meeting, but had provided his vote and rationale on Agenda Item #3. He also provided an update on the proposed Market Rule amendment previously submitted by Resolute Forest Products, advising Technical Panel members that the IESO had received notice of an application from Resolute to the Ontario Energy Board, calling for review of an existing market rule in accordance with Section 35 of the *Electricity Act*.

Members approved the meeting agenda with no amendments, on a motion by Joe Saunders.

Vlad Urukov provided two specific edits to the minutes of the previous meeting. The minutes were approved as amended on a motion by Mr. Urukov.

Agenda Item 2: Engagement Update

Jason Grbavac, IESO, drew members' attention to the engagement update in their information packages, noting that several of the items on the chart, beginning with the Phase I of the Transitional Capacity Auction (TCA) were on the agenda for today's meeting. He said the TCA engagement team was preparing to launch work on the next phase of the Capacity Auction with plans to schedule an education item with the Technical Panel as was done for Phase I. The review of the Technical Panel's composition and process, as recommended by the Governance and Decision-Making Advisory Group, was also on the Panel's agenda for August and September, with comments already received from Technical Panel members as well as the Market Development Advisory Group.

Hourly Demand Response (HDR) Out-of-Market Activation and Payments and Grid Connection Payments were both on the agenda as education and information items, while a Market Renewal Program (MRP) education item and annual omnibus package are scheduled for the Panel's last meeting of the year in November. Mr. Grbavac noted that the IESO was currently conducting monthly update meetings on MRP, which will shift to a bimonthly schedule once a series of single-issue items have been fully addressed. The August 26 session will focus on the business case for MRP, and Panel members are welcome to attend.

personal view that it was very important to move forward with the TCA in December, and that cancellation of the ICA represented an overall threat to some forms of market design.

Mr. Short said IESO staff agreed with the need for a complete assessment. But he stressed the underlying need to prepare for the anticipated capacity shortfall in 2023, adding that the transformation of the DR Auction was the first step in the required phase-in. Capacity is ultimately about system reliability, he said, and that was why the IESO proposed to complete the Transitional Capacity Auction Phase I, then continue deliberations in advance of the TCA, Phase II in June 2020.

Mr. Saunders asked how the December auction would be affected if the Panel postponed its decision. Mr. Short said a delay might leave staff with insufficient time to complete its pre-auction work, noting that the process called for an October 15 launch to give participants time to prepare for the auction to open on December 4.

The Chair noted that the current timeline called for a recommended Market Rule amendment package to be brought forward to August Board meeting, but said it was important that Panel members not feel pressured into a decision. The Chair noted that Technical Panel could delay the vote on this agenda item until later in the week, to give members a chance to review the AEMA/AMPCO legal brief in more detail.

In reply to a question from Mr. Collins, Mr. Short said a generator's participation in an auction would increase competition, but it would be impossible to predict what impact that would have on prices. Mr. Collins expressed concern that some market participants might not receive payments for their participation, a situation that amounted to discrimination that must be resolved in an expeditious way. Mr. Short reiterated that the IESO's paramount concern was to have a plan in place for 2023 which includes a capacity auction.

Mr. Samant asked whether the discussion applied to hourly demand response (HDR) as well as dispatchable loads, adding that utilization payments for dispatchable loads that had not participated in the DR auction would be a fundamental market change. Ms. Griffiths said the concern was with economic DR resources already participating in the energy market, and the difference between participating in the energy market versus a capacity market construct. Mr. Short clarified that this issue could provide energy payments for every load would participate in the energy market, whether or not they were a part of the DR market, and Mr. Samant reiterated that that represented a big change, since dispatchable loads have not received utilization payments since the market opened.

David Brown, OEB asked for clarification of the statement in the legal brief that the IESO had advised demand response participants to build utilization payments into their auction offers. Mr. Forsyth said loads had been looking for a provision similar to a utilization payment, and the IESO wasn't prepared to allow it, but advised entities to build the provision into their bids. In the new TCA rules, that advice applies to loads but not generators, which would incur costs and receive no corresponding payments.

Mr. Brown asked what equivalent provisions would apply to a generator entering the market today. Mr. Samant said he would assume the rules would be unchanged. Ms. Griffiths said the requirement to add the energy payments affected the competitiveness of her constituency's energy bids, potentially requiring bidders to adjust their auction offers accordingly.

Mr. Brown asked whether the advice to loads would be the same today. Mr. Short said it would still be up to the loads to decide how they wanted to participate in the capacity auction. If the Capacity Auction were to include energy payments, we expect the net benefit determination would be very complex as it should consider energy market participant bids/offers in the context of forecasted or actual energy market conditions. He added that the question was under review by the Demand Response Working Group.

A Panel member asked what costs a load would incur by participating in the auction under the current rules. Ms. Griffiths said the cost of stopping production would go well beyond availability prices for a capacity position and the dollars saved by not buying energy for that production.

Mr. Saunders asked whether the legal brief would be brought to the IESO Board's attention. The Chair said it would.

The Chair invited other views from members and observers. Candice Trickey, IESO said the DRWG would be addressing a number of related issues, including energy payments, which she noted is a difficult matter that has continued to receive considerable discussion in the United States. She said the working group had received initial feedback on the issue at its meeting in July, and would be putting forward a plan, timeline, and next steps to resolve the matter at its upcoming meeting on September 4. Additionally, IESO staff have a timeline for moving the item forward as quickly as possible, while following a stakeholder engagement process and having a transparent discussion, in which the IESO will engage with stakeholders to work through the issues and seek a resolution. One consideration, she added, is that energy payments should be provided when loads are activated if the practice delivers a net benefit to consumers. But if that approach was adopted, it would be necessary to understand how it would apply in Ontario.

Mr. Forsyth said he appreciated the explanation, but stated it had been a long time coming. The issue was on the table when the Demand Response Auction was first discussed, has remained on the DRWG's annual work plan, arose as a major issue at the first meeting on the Transitional Capacity Auction, and is now being dealt with as an emergency issue.

Mr. Brown noted that loads in Ontario are being economically dispatched against their own bid prices, in contrast to the FERC context where loads receive fixed recall rates and are dispatched for demand response at a price well below the spot price of electricity. Ms. Griffiths said dispatch on the PJM grid is based on scarcity prices, whereas price caps in Ontario are based on the bids that market participants submit. Mr. Forsyth said a PJM market participant would receive a favourable revenue stream anytime they were dispatched above a certain price per

TAB 11

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2019-0242**	**AMPCO Motion**
VOLUME:	**2**	
DATE:	**November 28, 2019**	
BEFORE:	**Cathy Spoel**	**Presiding Member**
	Emad Elsayed	**Member**
	Susan Frank	**Member**

Loyalist and the employees.

At this point in time I don't know what is going to happen because, as we all know, the recent ruling to stay the amendment of the market rules is forcing us into a fourth year of no participation in any substantial or viable revenue-generating contract, PPA capacity agreement, call it what you want. So that is the status of Kingston here today.

I think I would like to take this opportunity just to share one other aspect of Kingston and maybe to set some clarity based on what I've heard here and what I've read leading up to these OEB hearings this week.

There's been a lot of talk about fixed costs and variable costs, generators being paid, energy rents or energy payments and how that is unfair compared to load.

I just want to highlight that a facility like Kingston providing capacity to the system is providing exactly what the system needs. The system would be paying for the capacity.

If in fact there was an activation, that activation means that Kingston, or if it were another generating facility, would have to incur variable costs to meet that demand, and they are very telling, very predictable. We can put a price on them, and I can describe them here in five to ten seconds.

It is essentially the gas commodity that the business would have to procure in order to produce the energy to meet the system demand at that particular time. It is very easy for us to calculate what that is.

Going a step further, and I would say given the fact that it is a call for activation, that particular generator coming on to meet the system demand at that particular time is going to set the marginal price of electricity in the Ontario market. By default, if the generator was awarded the marginal price, or in Ontario it is called HOEP. We only have a single price in Ontario. That would cover our variable costs.

We are not looking for anything extra by getting paid energy payments under an activation in the capacity market. All we are looking for is to recover the variable costs associated with meeting the system demands at that particular time.

All we really are looking for is an opportunity to sustain that business as a capacity supply to the system, so that it can be there to meet those system demands under an activation when the system needs it. And in order to do that, we need to recover our fixed -- sorry, our fixed overhead costs.

What are our fixed overhead costs? It's very simple. That is our staff, our taxes, and our service contracts that are required; basically, the sunk or understood costs that you would have to incur in order to be there, in order to meet the supply of energy when the supply of energy is required.

By contrast, variable costs are actually the incremental costs that you need to incur in order to inject

Is that what you intended to do there?

MR. WINDSOR: Yes. But I would be happy to provide more clarity, if you think --

MR. MONDROW: Well, let me ask you a couple of questions, and maybe through that, and then if there is anything else of course quite happy to receive it.

MR. WINDSOR: Sure.

MR. MONDROW: As I read paragraph 7, the essential issue is that KCLP is competing against generators whose capacity costs are recovered under contracts. And you no longer have the support of the PPA, and that is essentially a problem for you?

MR. WINDSOR: Yes. And any other uncontracted generator out there. We are not the only one.

MR. MONDROW: Right. There are three others?

MR. WINDSOR: I don't know how many other -- again, I didn't do the math. There are other facilities in Ontario that have expired contracts, that could be providing capacity to the Ontario system.

MR. MONDROW: Right. As a result of the PPAs that continue to exist for the vast majority of generation in Ontario, the wholesale energy market prices reflect only generator ~~of~~ variable costs, and you testified to that already this morning, right?

MR. WINDSOR: Yes.

MR. MONDROW: Okay. And you also testified that KCLP incurs costs to continue to operate beyond your variable, or you characterize them as your gas supply costs, and you call them fixed operating costs, I think?

MR. WINDSOR: No. So I do need to clarify that.

MR. MONDROW: All right.

MR. WINDSOR: So the gas costs are actually part of the variable costs.

MR. MONDROW: Sorry, when I said "them" I didn't mean the gas costs. Sorry, I was inaccurate.

The gas costs ~~and~~ Are the variable costs, you get those back through HOEP? Because every other generator has to recover those through their energy bids.

MR. WINDSOR: Correct.

MR. MONDROW: But the other generators recover fixed costs through their contracts, you don't have the contract, and so that is the problem?

MR. WINDSOR: Yeah. That's the problem. And to be most clear, that is the model of the system in Ontario, and it's not that different at a fairly high level of the model of any other capacity market in Ontario.

The only thing that is really different is, we're talking about a capacity payment -- which is in fact a form of a power off-take agreement -- versus a PPA, which is a more -- more of your legacy-type standard, more standard long-term power off-take agreements, right?

So they both behave the same way. For a generator or a developer of a power project, that is what covers the project costs.

MR. MONDROW: And so what KCLP wants is to have a capacity obligation, or we could call it a capacity contract, to recover your fixed operating costs and then continue to recover your variable operating costs in the energy market?

MR. WINDSOR: Correct. When the generator would be called to market under an activation.

MR. MONDROW: Right. When you incur those variable costs.

MR. WINDSOR: Right. And I think we have all agreed in previous discussions leading up to now that nobody expects that that would be material.

MR. MONDROW: Yes. Well, we will talk about that later.

If you could go back to our compendium. This is K2.2. Behind tab B is a copy of KCLP's response to APPrO Interrogatory No. 2. Are you familiar with this response?

MR. WINDSOR: Yes.

MR. MONDROW: Okay. And if I look at the question, the question that APPrO asked is, can you please confirm whether KCLP stands to gain "millions of dollars" should it successfully clear the December 4th, 2019 TCA, and you say in your response that is not correct.

And I gather from reading the rest of the response and in particular the last sentence that the "millions of dollars" reference really was a reference to the situation you hope will obtain when the 2023 forecasted capacity gap arises, not in December of 2019.

MR. WINDSOR: So I think -- I think maybe this whole discussion that we're talking about right now has been undertaking, right?

MR. MONDROW: Yes, it is.

MS. DJURDJEVIC: Yes.

MR. MONDROW: Sorry, Mr. Windsor, you wanted to say something?

MR. WINDSOR: I do.

MR. MONDROW: Something else.

MR. WINDSOR: Under the speed, no load program or the generator cost guarantee program, what you are talking about is a program that the IESO has for generators who are gas-fired generators to recover their start-up costs, which allows them to get the unit online and be dispatchable for the system to meet the system demand at that point in time.

The variable costs associated with meeting system demand, once you get through your start-up -- which is essentially running the machine up from zero to 3,600 rpm -- probably represents -- and I am comfortable saying somewhere in the whereabouts of about 10, 15 percent of your overall variable costs, and of course that would be dependent on how long the machine is actually on in the system. So if it's on for eight hours, ten hours, which is typically how long these units run through the peak hours of a generation day, I am comfortable saying that that would recover maybe 10 to 15 percent of the overall variable costs associated with turning the unit on.

MR. MONDROW: Sorry, when you say "that" are you referring to the energy payments or the generator cost guarantee --

MR. WINDSOR: No. I am making reference to the program that you are asking me to undertake.

MR. MONDROW: So the generator cost guarantees allow you to recover roughly 10 to 15 percent of your costs of running and the balance you recover in the energy payment.

MR. WINDSOR: Ballpark, recognizing there is a number of variables.

MR. MONDROW: Ballpark, got it. That is helpful. Thank you.

Thank you, Madam Chair, those are my questions. Thank you, Mr. Windsor.

MR. WINDSOR: You're welcome.

MR. MONDROW: Hope you get your capacity auction.

MS. SPOEL: According to my list Mr. Mondrow is the only person who has indicated he wished to cross-examine Mr. Windsor. Is that correct? All right.

DR. ELSAYED: Yeah, just maybe a couple of clarifications.

QUESTIONS BY THE BOARD:

DR. ELSAYED: Mr. Windsor, I think you mentioned that as a result of the stay decision by the OEB Kingston will not be able to participate in the market for at least a year. Can you clarify that, explain that a bit?

MR. WINDSOR: I would be happy to. So the schedule date for the demand response auction now or what was going to be the transitional capacity auction is December 4th.

And so we've been advised by the IESO, and they've gone public -- although I haven't seen it, I was told

TAB 12

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ONTARIO ENERGY BOARD

FILE NO.:	**EB-2019-0242**	**AMPCO Motion**
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	Emad Elsayed	**Member**
	Susan Frank	**Member**

of my questions.

MS. SPOEL: Thank you, Mr. Barz.

Mr. Mondrow.

MR. MONDROW: Thank you, Madam Chair. I do have a few questions.

MS. SPOEL: Great.

CROSS-EXAMINATION BY MR. MONDROW:

MR. MONDROW: Good afternoon, gentlemen. Mr. Goulding, I can refer you if you wish to page 31 of your report. In Staff's compendium it has come out as page 60 of 86. It might be easier to find it there.

And I just -- you mentioned off the top I think in your direct examination some of your primary or basic conclusions.

Am I correct that one of your conclusions is that there is a strong practical linkage between capacity market participation by DR resources and activation payments?

MR. GOULDING: I would like to recharacterize that a bit if I could, which is, first of all, resources are not going to participate in any form if they don't perceive it to be remunerative.

And the part of what they're seeking compensation for is the risk of being activated and the costs that will be incurred.

So when we look at the market rules specific to the capacity mechanism and the energy market, the market rules need to enable the DR participant to recover the total of their need across the multiple product streams.

So conceptually, if we're recovering nothing in the energy market, we need to recover everything in the capacity market. And consequently as we bid into the capacity market, we need to guess how often are we going to be activated and what are the consequences of that and make sure that we have a margin, if we guess wrong, that is built into our capacity bid.

So I would say that an understanding of the potential for activation and the financial consequences is critical for the DR resource to determine their bid in the capacity mechanism.

MR. MONDROW: So if you look at the page I referenced in your report under heading 4.4.5, you see the highlighted strong practical linkage language, which is where I took that phrase.

But I think at the bottom of the next paragraph you sum up what you just explained, which is you say:

> "This activation payment is therefore directly linked to participation on the capacity side."

And I think you just explained that. Is that -- my understanding of that sentence correct?

MR. GOULDING: Yes.

MR. MONDROW: Thank you. And am I correct that another one of your primary conclusions is that demand response participation in Ontario is proportionately lower than demand response participation in the U.S. FERC jurisdictional -- U.S. FERC jurisdictional -- jurisdictions that you looked at?

TAB 13

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And you don't disagree that DR load bid prices under the DRA have averaged about 1,500 megawatts an hour, do you?

MR. ANDERSON: I don't dispute that, no.

MS. KRAJEWSKA: No. And at paragraph 38, the IESO states that:

"HDR resources have only been economically activated on one occasion since the introduction into the DRA."

You don't dispute that either.

MR. ANDERSON: I don't dispute that.

MS. KRAJEWSKA: And in paragraph 39, that:

"Dispatchable loads have been economically dispatched less than 1 percent of the time over the same period."

You don't dispute that either?

MR. ANDERSON: I don't I don't dispute that both dispatchable loads and HDR resources haven't been activated very often, and I would also expect that their activation energy offers are high. And I would say that if I was going to get paid exactly zero dollars for activating I would keep my energy offers high too.

MS. KRAJEWSKA: Well, we will get to that.

Mr. Anderson, at paragraph 15, which is at tab E for echo, of my compendium. Paragraph 15 of your affidavit. And my friend Mr. Barz has already taken you to some of the -- sorry, you spoke about this in your examination in-chief.

TAB 14

OEB STAFF INTERROGATORY 8

INTERROGATORY

Ref: Presentation to IESO Board - IESO Market Rule Amendments: Transitional Capacity Auction, August 28, 2019, p.6

Questions:

(a) IESO staff notes at slide 6 in the presentation that "Access to energy payments for DR resources with a capacity obligation has not been material historically nor is it expected to be material under the TCA rules for the December 2019 auction". Please explain this statement, including the meanings of "access" and "material" in this context.

Further on slide 6, IESO staff also notes "Economic activations of DR resources have been very limited to date, and we do not expect the likelihood of economic activation to increase appreciably in 2020".

(b) Please clarify the number of economic activations of DR resources in each year since the DRA was introduced in 2015 for: (1) HDR resources; and (2) Dispatchable load resources.

(c) Please describe the IESO's expectations for 2020 in relation to the number of economic activations of DR resources under the current TCA design. Please describe the anticipated market conditions (such as total load, MCP and/or HOEP) at times when activations, if any, would be expected.

(d) Would IESO expect the frequency of activations to change if DR resources received an energy payment and, if so, how?

RESPONSE

(a) In the referenced statement, the term "access" means an opportunity for a DR resource to receive an energy payment if activated. The IESO stated that access has not been historically "material" because HDR resources have only been economically dispatched on one occasion since the introduction of the DRA in 2015 and dispatchable loads have been dispatched less than 1% of the time over that same time period.

Based on the historical infrequency of DR resource activation in the DRA, and the IESO's short-term forecast for capacity need, the IESO estimates a very low probability of economic DR resource activation during the December 2019 TCA commitment period. Given this low probability of DR resource activation, theoretical access to energy payments should have no material impact on DR auction offers, and so would have no effect on their competitiveness in the auction.

(b) The number of activations under the DRA by year are shown on the table below for DL resources only.

	Activation (Interval Based)	Percentage of All Intervals within hours of availability (Interval Based)	Activation (Hourly Based)	Percentage of all hours within hours of availability (Hourly Based)
2016 (Since May 1st)	244	0.40%	74	1.45%
2017	142	0.20%	44	0.72%
2018	79	0.10%	34	0.49%
2019 to date	64	0.09%	23	0.38%
Total	529	0.18%	175	0.72%

Where:

- Activation (Interval Based) – Occurrences (count of intervals) that DLs were activated
- Activation (Hourly Based) – Occurrences (count of hours) that DLs were activated

Percentage of all hours within hours of availability - percentage of all hours within the availability window of the mentioned period

There has only been one activation for three hours of an HDR resource, this occurred in July, 2019.

(c) The IESO does not anticipate any change in the frequency of activations for the December 2019 commitment. There has been no material change in the target capacity for the December 2019 commitment period (675 MW for summer and winter commitment periods) as compared to the December 2018 commitment period (611 MW for summer and 606 MW for winter). The total target capacity is negligible in the context of total system need.

The IESO does not anticipate any activations of HDR resources during the December 2019 commitment period.

The IESO does not anticipate any activations of HDR resources and anticipated a similar historical activation of DL resources during the December 2019 commitment period.

(d) No. For the reasons described in paragraph (a), the IESO would not expect any energy payments to be material in respect of the December 2019 commitment period. Therefore, the IESO does not expect that the availability of an energy payment would influence frequency of activations of DR resources. As Navigant stated in section 3.1.5 of its report (Exhibit "I" to the Affidavit of David Short sworn October 25, 2019, "[l]arge commercial and industrial customers with a high value of lost load are not likely to change their bids into the energy market because of utilization payments".

EB-2019-0242

ONTARIO ENERGY BOARD

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO

APPLICATION TO REVIEW AMENDMENTS TO THE MARKET RULES MADE BY THE INDEPENDENT ELECTRICITY SYSTEM OPERATOR.

EVIDENCE OF THE INDEPDENENT ELECTRICITY SYSTEM OPERATOR

November 8, 2019

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38. HDR resources have only been economically activated on one occasion since the introduction of the DRA in 2015. The Market Surveillance Panel of the Ontario Energy Board noted, in its Monitoring Report of the IESO-Administered Markets published in May 2017, that "the likelihood of an activation is remote".[5] The Panel observed that between May and December 2016, 82% of HDR resources offered bid prices were $1999/MWh while the remaining 18% of HDR resources offered bid prices were $500/MWh. The Panel further concluded that any bid price over $220/MWh would not have been activated during the period.

39. Dispatchable loads have been economically dispatched less than 1% of the time over that same period.[6] These activations generally occur due to localized short-term price spikes resulting from contingencies such as unanticipated generation and transmission outages.

PART V - ENERGY PAYMENTS FOR DR RESOURCES

A. What are energy payments for DR resources?

40. Reference has been made in this proceeding to both "utilization payments" and "energy payments". A utilization payment is a generic category which includes energy payments.

41. Energy payments for DR resources, which is what AMPCO is seeking in this Application, would be payments to loads that bid into the energy market and reduce energy consumption based on the applicable wholesale market clearing price.

B. How are DR resources treated in the IESO energy market?

42. The design of the IESO energy market was based on the recommendations of the Ontario Market Design Committee and on standard market design in other jurisdictions in North America.

43. Ontario's energy market design, as codified in the market rules, provides that generators and loads may be either dispatchable or non dispatchable; and, that

[5] Attached at **Tab "2"** is the *Monitoring Report on the IESO-Administered Electricity Markets*, Market Surveillance Panel, dated May 2017.

[6] Attached at **Tab "3"** is the IESO Response to the Board Staff's Interrogatory No. 8.

IESO UNDERTAKING J3.4

UNDERTAKING

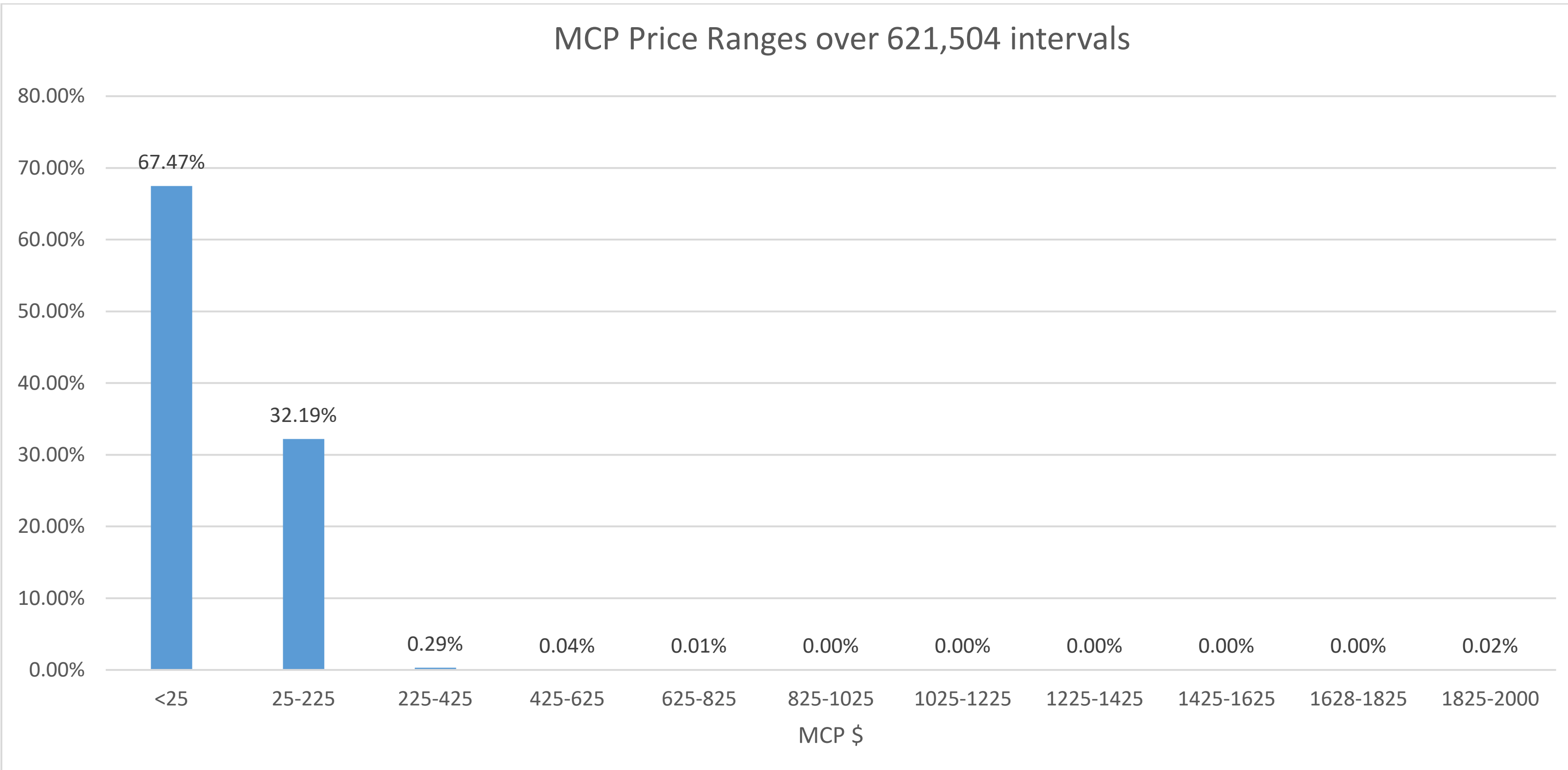
To produce a distribution graph of five-minute-interval real-time energy prices in $200 increments, between $25 and the maximum over the last five years

RESPONSE

The distribution graph for the over 621,000 5-minute intervals over the last five years is attached.

UNDERTAKING NO. J3.4:

TO PRODUCE A DISTRIBUTION GRAPH OF FIVE-MINUTE-INTERVAL REAL-TIME ENERGY PRICES IN $200 INCREMENTS, BETWEEN $25 AND THE MAXIMUM OVER THE LAST FIVE YEARS.



TAB 15

ONTARIO ENERGY BOARD

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	Susan Frank	**Member**

its analysis and respond, LEI's opinions are preliminary and subject to change. With that caveat in mind, LEI's views are as follows..."

And in the first paragraph you state:

"Based on the markets and programs LEI reviewed in its report, actual activation of DR resources has been relatively limited, and DR resource revenues from this activation have also been limited as compared to DR capacity revenues," and you reference section 4.4.

So that ties to those bullets we were looking at in your report, correct?

MR. GOULDING: Yes.

MR. DUFFY: You then state:

"This implies that from a practical perspective, the benefit or harm arising from whether DR resources are provided energy payments may not be material in the near term."

Correct?

MR. GOULDING: Yes.

MR. DUFFY: And am I right to take from that that whether or not there are energy payments made to DR resources, you view them as immaterial because the likelihood of being activated is so infrequent?

MR. GOULDING: So I want to be clear over what time period we're talking about, and as to whether I view this as an important issue over the long run.

So over the long run, I believe it is an important issue and may become more material over time.

Over the short run, based on the historical participation, with the acknowledgement that one of the reasons that I'm concerned over the long run is that I do expect there to be change.

But over the short run, if we actually went and calculated the amount of money that is at stake, and that amount of money would be at stake only for this particular auction period, I believe that amount to be relatively small and perhaps absolutely small.

MR. DUFFY: Right. So if I were to put to you, for instance, that if dispatch is going to be extremely infrequent, then the risk premium that one needs to build into their capacity auction bid would be negligible or almost zero, correct?

MR. GOULDING: I don't believe it would be zero. And we can imagine circumstances where the market conditions could change quite suddenly, right.

And so if I were a DR resource, I don't think that I would be wise to assume zero.

MR. DUFFY: But if you were a DR resource and the historical activations in Ontario are extremely infrequent, and even activations in other markets where payments are made is extremely infrequent, you will agree with me that in either scenario, you would treat your bid the same way. No?

MR. GOULDING: I think that the historical information would cause my risk perception to be low and perhaps biased. But it would certainly cause my risk perception to be low.

MR. DUFFY: Thank you. Those are all of my questions.

MS. SPOEL: Mr. Rubenstein?

CROSS-EXAMINATION BY MR. RUBENSTEIN:

MR. RUBENSTEIN: Good afternoon, panel. My name is Mark Rubenstein. I am counsel for the School Energy Coalition. I was wondering if you could first pull up -- actually, before you do that, I would like to follow up with some questions you were just being asked, where you were asked -- you caveated your answer about what the definition of short or long-term, what you're talking about.

I just want to be clear and very specific. When you were talking about in the short term, are you specifically talking about the commitment period for the auction that is supposed to take place in December?

MR. GOULDING: Yes.

MR. RUBENSTEIN: But you are not talking about necessarily -- or let me ask you. What type of time period, is it short term or long-term would we talk about in, say, 2023 where there is a forecasted capacity gap, I think we heard this morning, of somewhere between 3500 to 4,000 megawatts.

Is that closer to the short term or to the long-term, in your view?

MR. GOULDING: So my answer was intended to relate solely to the auction at hand, with the understanding that there will be the opportunity for further review before the next auction takes place.

MR. RUBENSTEIN: But let's put aside that there may be further review for a moment. I just want to understand from your perspective, because I understand that TCA auction is leading up to the -- the intent of it is to lead up ultimately to the larger capacity gap that will exist in 2023.

So I am just trying to understand your view. In 2023, do you think it makes sense then to provide energy payments? Or is it more likely that because it would be more likely to be activations by then?

MR. GOULDING: So what I believe is that a process for further study is necessary soon with regards to these issues, so that we can come to a clear understanding of consequences prior to 2023.

MR. RUBENSTEIN: I was wondering if we could turn up your response to KCLP number 4. And this is on page 79 of 86 of the Staff compendium. Sorry, KCLP number 6. Page 83 of 86. Number 6.

So you were asked in part B:

> "Does LEI agree with Mr. Rivard that as a result of the global adjustment the net benefits test will be satisfied less frequently, if ever, than in the U.S. markets?"

Do you see that?

MR. GOULDING: Yes.

MR. RUBENSTEIN: And in your response you say:

> "LEI does not believe the net benefits test as

[Laughter]

DR. ELSAYED: Is this better?

MR. GOULDING: Yes.

DR. ELSAYED: My question is similar to one I asked before, but there may be some overlap with what Ms. Frank just talked to you about.

Again, we heard quite a bit today about the historical fact that DR resources in the Ontario market have not been economically activated very frequently.

Based on your knowledge of other markets, under what circumstances can that change in the Ontario market going forward?

MR. GOULDING: Well, I think that -- again looking short term and long-term -- over the short term, a sudden supply shock would produce a sort of an all hands-on-deck-type situation under which DR, I think, would be called upon much more frequently.

And so for me, I believe that the most likely scenario is something goes dramatically wrong with a nuclear program over a time frame that is too quick to respond, right, you know, that in that period before you can bring every barge-mounted simple cycle gas turbine on the planet to float in Lake Ontario, you have to meet the short term needs of the system -- and look, in this day and age, you would probably meet that with a mix of batteries and other things, but you probably would be bringing in some short term resources.

I think under those circumstances, the system operator is going to be calling, where appropriate, as much DR as possible.

So if we imagine a hot summer, a higher than expected number of nuclear outages, a hot summer might mean that wind doesn't produce what you would expect, you might have poor hydrology as well. So, you know, annoying though the phrase perfect storm is, we can nonetheless imagine a not completely I implausible set of circumstances that could occur over the near term that would cause DR to be activated much more than anybody expected, but consistent with the market rules.

DR. ELSAYED: And the longer term.

[Laughter]

MR. GOULDING: So in the longer term -- I shouldn't say I have visions, right.

[Laughter]

MR. MONDROW: Not on the record.

MR. GOULDING: Not on the record, yes.

[Laughter]

MR. GOULDING: Yes. We can imagine a market that -- getting back to what I said about an increasing number of intermittent resources, if we believe that demand response participation can provide a highly flexible, valuable way of balancing supply availability, we can imagine a circumstance where it becomes a much more active part of the energy market.

And so and -- look, I mean we have, you know, some projections that show batteries serving this role and ultimately the market will determine the relative costs of keeping a big battery available versus ramping down one or more large loads. But the market is going to value highly flexible resources that will serve to balance intermittent resources. And so this means that there is certainly an expectation that very sophisticated kinds of demand response would play an increasing role in that world.

DR. ELSAYED: That's all for me, thank you.

MS. SPOEL: Thank you. I just had one question which nobody has really touched on at all.

But when you are talking about net benefits, to what extent do you look at any externalities such as appropriate carbon pricing, if you are looking at the alternative between demand response, for example, and increased generation, which is usually fossil fuel. Or does that not really factor into it from the...

MR. GOULDING: First of all, what I hope that we're talking about is designing a good net benefits test, right. One that is that is effective for Ontario and is consistent with, you know, economic theory.

And proper pricing of externalities I think is critical to making the right decisions for society as a whole.

Now, there are distributional impacts that come into play. And I think that, you know, we can imagine a situation where you are just shifting between gas-fired generation, right. It is just whether it is in front of or behind-the-meter.

And so, you know, under those circumstances the

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	Susan Frank	**Member**

happens.

MR. MONDROW: Okay. And again, that would be functional equivalence, not horizontal equity or vertical equity, right?

DR. RIVARD: Yes.

MR. MONDROW: Okay. You talked with Member Frank a bit about market history in search of a silver bullet which we haven't yet found, and maybe we won't find in quite that way, but I did want to come back to that concept for a minute.

If demand response is seeking and continues to seek a more active role in the market, that would be a change, right? Demand today is not the same as demand in 2002. There is different technology, there's a different way of approaching energy services. Would you agree with that?

DR. RIVARD: Certainly things have changed a lot since 2002. I do think there are technologies available that might allow certain participants to be more responsive to a price.

MR. MONDROW: If they invest in those technologies.

DR. RIVARD: If they invest in those -- to the extent a technology investment is required and that technology is available, yes, I think there are differences, technological differences now, that weren't available back then.

MR. MONDROW: And a payment stream of some sort to demand response resources, whether energy or some other administrative price, would impact the calculus for the optimal use of resources in respect of those investments in these new and emerging technologies, would it not?

DR. RIVARD: If I am a demand response resource -- if I understand your question, but interject if I am off-track -- but if I am a demand response resource, that could be more responsive by investing in, say, some control systems, then there has to be an economic case for me to do so.

That economic case could be simply that in the past there were situations where prices got really high, I didn't have the technology to reduce my demand, I ended up paying a price that was well above what I after the fact wish I would have, but now this technology is available, and I am willing to invest in that technology to avoid that situation. I think that is possible.

MR. MONDROW: Could I take you to 1A prime and 1B prime, which are pages 55 and 56 of the compendium? You spent a little bit of time on this. I just have a few more minutes, Madam Chair, and then we can a lunch break. I think a few more minutes. I shouldn't presuppose. Let's not presuppose anything just yet, Dr. Rivard.

So we will start with 1A prime, that's fine, thank you.

I want to ask you a question about 1A prime. If I look at the opportunity cost of availability, the thousand-dollar figure that Member Frank I think was -- or maybe it was Member -- Chair Spoel was asking you about.

Why is, on the DR Corp. side, that thousand dollars not lower -- that is, its cost -- why is it not lower by

TAB 16

Demand response programs in selected US markets

prepared for the Ontario Energy Board staff by London Economics International LLC ("LEI")

November 8th, 2019

Federal Energy Regulatory Commission ("FERC") Order 745 established that demand response resources participating in organized wholesale energy markets (day-ahead and real-time) would be compensated through the payment of the locational marginal price for curtailing their load if dispatched. However, Order 745 did not directly impact the majority of demand response resources participating in programs administered by the two US Independent System Operators ("ISO") and one Regional Transmission Organization ("RTO") that LEI reviewed, as these demand-side resources tended to serve more as capacity providers. Demand response resources as capacity providers make up the majority of demand-side participation in the ISO and RTO programs that LEI reviewed, and capacity payments make up the bulk of their total compensation (although additional payments are made if these resources are actually activated). In contrast, the total dispatch of demand response resources through ISO and RTO programs reviewed by LEI was low, as were revenues associated with dispatch.

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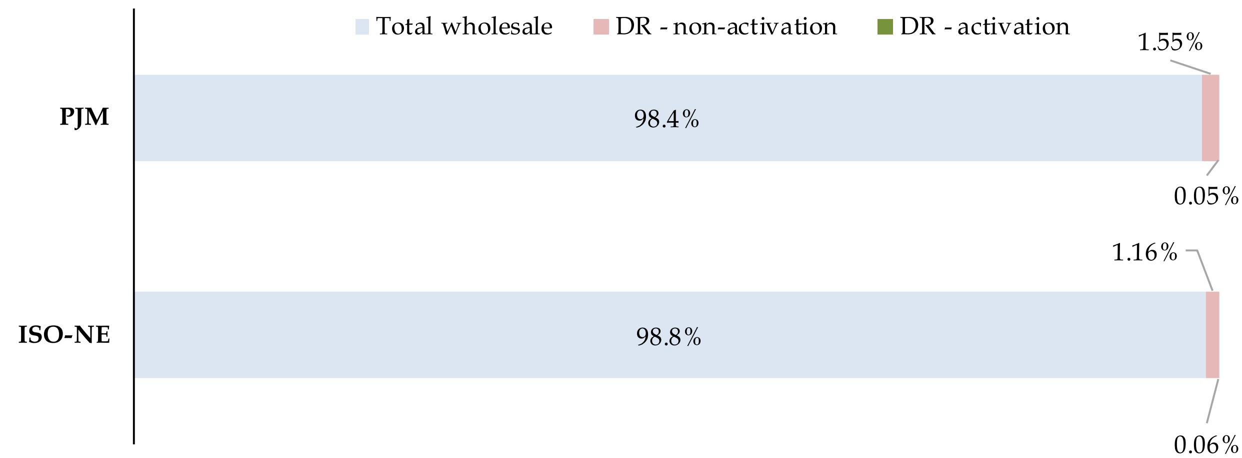
and emergency), and those related to non-activation (capacity in ISO-NE, capacity and ancillary services in PJM). Total DR payments made up around 1.2% of wholesale electricity costs in ISO-NE between 2010 and 2014, and 1.6% in PJM between 2010 and 2018. Activation-related DR payments were a fraction of this fraction, at only 0.06% of wholesale electricity costs in ISO-NE and 0.05% in PJM.

Figure 25. Total payments made to DR relative to total wholesale payments (%)



Sources: See Figure 23 and Figure 24

4.4.5 Degree of connection between energy payments for DR activations and capacity markets

While, as discussed previously, both the total revenues and total dispatch/activation from participation on the energy side directly or through emergency/reliability activations is low, there is still a **strong practical linkage** in these markets between participation on the capacity side and payments for activation or dispatch.

Most DR resources in the markets reviewed by LEI **participate through the provision of capacity**, in emergency or reliability-related programs in PJM and NYISO, and as active DR in ISO-NE. In NYISO and PJM, although Order 745 does not apply to these programs, when resources that participate in them are called upon to curtail, they are paid (in $/MWh terms) for this curtailment.[43] This activation payment is therefore directly linked to participation on the capacity side.

In ISO-NE, active DR with capacity obligations have must-offer rules in the energy market, therefore energy market participation is directly linked to capacity participation for DR resources in New England.

[43] In PJM, a small fraction of emergency and pre-emergency demand response is registered as capacity only, meaning they do not get payments for activation. There was 1.8% of emergency and pre-emergency demand response registered as capacity-only for the 2017/2018 delivery year, and 1.2% for the 2018/2019 delivery year. Source: Monitoring Analytics. *2018 State of the Market Report for PJM: Section 6 – Demand Response*.

TAB 17

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	Emad Elsayed	**Member**
	Susan Frank	**Member**

And -- but that is not the case for DR. So I think that you can draw some conclusions from these graphics that are consistent with what you are looking for.

MS. FRANK: One last question, then I will let it go.

You said that looking at this data was only, you know, a short period of time and for a few markets. But we have qualified you as experts. So you can tell us about, in your expert opinion, how are things changing over time.

Is there going to be capacity markets that are primarily generation? Or are they primarily load? What is happening over time? In your expert opinion what are you going to tell us?

MR. GOULDING: So we could spend a day on that, and I will try not to.

MS. FRANK: Yes, please don't.

[Laughter]

MR. GOULDING: So the role of capacity markets is changing, more broadly. And the reason for that is that we have an increasing prevalence of zero marginal cost resources that are mostly intermittent, but not entirely.

Now, what that means is that when those intermittent resources aren't available then we need to pay some other kind of resource, often a fossil-fuel resource, to operate.

The expectation is that over time this is going to make energy market prices more volatile. That increases the risk if you don't have any other revenue stream.

And so I believe that it is reasonable to assume -- again, in general, across multiple jurisdictions -- that the role of the capacity mechanism is going to increase because you are going to have potentially a lot more flexible plants that are waiting around to be called, and in a good year they might not be called at all -- well, your definition of "good" needs to be clarified here, right?

In a year in which there is significant production from intermittent and zero marginal cost resources, those resources aren't going to be called.

It is similar to the challenge that we see in hydro-dominated Latin American markets, which are, good hydrology year, you don't need any of your gas plants, and in a bad year, you need more than you have. So how do you figure out how to pay those gas plants to stick around?

So my belief is that for all resources, capacity markets -- or mechanisms, as I prefer to call them -- will become a larger proportion of the overall market revenues.

I think in addition, we're going to see a greater diversity of ways in which consumers obtain their electricity. And to the extent that any of them are doing that outside of traditional market mechanisms, or at least what we think of as wholesale and retail, that's also going to change the divide between capacity and energy.

MS. FRANK: Okay, thank you for those thoughts.

DR. ELSAYED: Can you hear me?

MR. GOULDING: Yes.

DR. ELSAYED: This microphone -- I guess I will have two microphones, so I will try to use both of them.

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FILE NO.:	**EB-2019-0242**	**AMPCO Motion**
VOLUME:	**2**	
DATE:	**November 28, 2019**	
BEFORE:	**Cathy Spoel**	**Presiding Member**
	Emad Elsayed	**Member**
	Susan Frank	**Member**

that drives it. So a person with a lower fixed avoidable cost will do better in the auction.

DR. RIVARD: Yes. And I think we want that from a society standpoint, right?

MS. SPOEL: I don't know. I don't know what we want from a -- I am asking you in terms of --

DR. RIVARD: Yes.

MS. SPOEL: -- this. I am trying to understand the numbers here, which numbers, which numbers -- which are the numbers that are actually driving the -- what you end up with at the bottom of the page when you have gone through all of the various calculations, but the number that drives it, the underlying assumption that drives it is that the fixed avoidable costs are the same, not that the dollars per megawatt-hour are the same or anything else, but it is the fixed avoidable costs that are the same. They're the equivalent number or same number that allows you to do this comparison.

DR. RIVARD: Yes.

MS. SPOEL: I wanted to understand for myself.

DR. RIVARD: Let me kind of explain that further. I specifically created a situation where the fixed avoidable costs of the two participants were the same to highlight the kind of the negative outcome that could happen.

And what the IESO is trying to do in its capacity auction is say, hey, we need someone to be available for reliability to either produce electricity or reduce demand, we want to make sure that whatever the cost of any participant is to be available to do that, we want to make sure we choose -- from the standpoint of running the market fair and efficiently, that we choose the lowest cost one first.

And that if the generator in this case had a much lower avoidable cost, even paying the demand response resource, which I think would provide it preferential treatment, even paying it, you might still get the generator company being successful in the auction, you're right.

MS. SPOEL: I just wanted to understand what the driver was. I think it is that equivalent fixed avoidable cost or the same.

DR. RIVARD: That's right.

MS. SPOEL: Thank you. That is really helpful.

MS. FRANK: Can I ask, in table 1B, under the demand response, the energy is zero. I am a little -- where does the zero come from? I understood the 600 when I was looking at 1A, but I don't -- I don't know what the zero is under 1B.

MS. KRAJEWSKA: That is energy at VoLL on the DR Corp side.

MS. FRANK: Yes, right.

DR. RIVARD: Right. So in this case, remember that if it's available and it bids $75 and the market clearing price was $100, it wouldn't be available to produce a product. It would reduce its demand.

So the energy at VoLL really is supposed to say how

TAB 19

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November 27, 2019

Delivered by Email, RESS & Courier

Ms. Christine Long, Registrar and Board Secretary
Ontario Energy Board
P.O. Box 2319, 27th Floor
2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms. Long:

Re: Application for Review of an Amendment to the Independent Electricity System Operator Market Rules
Board File No. EB-2019-0242
Kingston CoGen Limited Partnership - Witness Statement of Brian Rivard

Please find enclosed the Witness Statement of Brian Rivard in the above-captioned matter. Paper copies of this letter and the accompanying Witness Statement will be delivered to you by courier.

Should you have any questions or require further information in this regard, please do not hesitate to contact me.

Yours very truly,

BORDEN LADNER GERVAIS LLP

Per:

Original signed by Gian Minichini

Gian Minichini

cc: John Vellone, BLG
Ewa Krajewska, BLG
John Windsor, Northland Power Inc.
James Hunter, IESO
Colin Anderson, AMPCO
Ian A. Mondrow, Gowling WLG
Michael Bell, OEB Staff
Intervenors of Record

Witness Statement of Dr. Brian Rivard

In my examination in chief, I intend, *inter alia*, to respond to two issues raised by Colin Anderson in his witness statement dated November 22, 2019, and further discussed by Mr. Anderson in his subsequent testimony before the Ontario Energy Board on November 25, 2019.

1. **Issue 1:** Does the analysis change when a DR resources does not have behind-the-meter ("BTM") generation?

Response:

The purpose of the examples in my affidavit (as revised November 21, 2019) was to show that the Amendments are consistent with the principle of horizontal equity and by this principle, the Amendments are not discriminatory.

Horizontal equity requires that individuals or corporations that are alike in all relevant respects are treated the same. The examples show how two companies, that are identical in all relevant respects (both demand and supply), and that differ only by the arbitrary placement of a meter, would be compensated the same under the Amendments. This is consistent with horizontal equity. By extension, when the DR resource receives an energy payment (the market price) to curtail demand, the DR resource receives preferable treatment. This is inconsistent with horizontal equity.

Mr. Anderson assumes a different situation in which a DR resource does not have a BTM generator to supply its own demand. This sets up a comparison of two different individuals: a DR resource without a BTM generator to a generator. This comparison requires consideration of the principle of vertical equity, which states that individuals that differ in relevant respects should often be treated differently. The challenge for evaluating what is vertically equitable is in determining a principled basis for the differential treatment. I propose that a constructive way to think about this is to understand what the purpose of the TCA is and hence to evaluate the differential treatment of different participants in the auction against this purpose. The purpose of the TCA as stated in the evidence is to promote or enhance competition and efficiency to the benefit of Ontario consumers.

I offer the following example to show how the Amendments are consistent with the promotion of fair and efficient competition. Attached are Figure 1.A' and 1.B' that illustrate implications on efficiency and competition. The example shows that if a DR resource and a Generation resource each needed to recover a $1,000 fixed avoidable cost in order to be available, the Amendments result in an outcome that is efficient. Both are incented to offer in the capacity auction at a price that just recovers this cost. By this principle, it is vertically equitable.

If instead, DR Resources are paid the market price to reduce demand, then they are incented to lower their bid price to the point where it is indifferent between consuming or being paid not to consume (i.e., $75/MWh). In this scenario, the DR resource forgoes some productive value from consumption, equal to the difference between what it is willing to pay, $150/MWh and the market price it would pay $100/MWh (i.e., $50/MWh) in order to receive a payment of $100/MWh. This would be inefficient from a societal standpoint because the value to society from producing the good ($150/MWh) is greater than cost to society to produce the electricity needed to produce the good ($100/MWh). Paying the DR resource therefore induces inefficiency. Furthermore, it provides the DR resources a competitive advantage in the TCA against a generator that has the same avoidable cost. By this standard, paying DR resources the market price when activated is vertically inequitable.

2. **Issue 2:** Mr. Anderson states:

> Dr. Rivard suggests that providing a DR resource with capacity payments rewards it twice for the same demand reduction if the resource also participates in the Industrial Conservation Initiative (ICI) peak reduction program. Dr. Rivard is mistaken about this. If a DR resource reduces load for the purposes of reducing its peak for ICI calculations, that reduction would by definition be unavailable to the market and the IESO would thus claw back availability payments for the period during which the resource was not available at a 2:1 ratio.

Response:

Mr. Anderson is correct to say that if a DR resource intentionally ignores its obligation under the TCA to benefit from the ICI program, it is subject to a daily Availability Charge for the hours in the day that it was not available to meet its obligation. The Availability Charge is equal to the daily unavailable MWh times the daily availability payment divided by the number of hours in the day the DR resource was obligated to be available. In the peak demand months, this charge is doubled. So, for example, assume the DR resource was obligated to make 1 MW of demand reduction available in 9 hours in a day during a peak month, and the TCA auction provided a daily availability payment of \$230/ MW- day (the TCA capacity clearing price). If the DR resource decided that it was in its financial interest to not meet its TCA obligation for the entire day in order to instead benefit from the ICI and avoid the Global Adjustment, it would be subject to an Availability Charge equal to:

Availability Charge = Unavailable MWh x Hourly Availability Payment x Factor of 2

= (1MW x 9hrs) x ((\$230/MWh – day)/9 hrs) x 2

= \$460

However, this does not change the conclusion illustrated in Figure 4 of my affidavit. In all other days, the DR resource would receive an Availability Payment if it makes itself available, that can be used to offset the fixed avoidable cost of being available to reduce system demand. It would have the double incentive to incur the fixed avoided cost because it would allow it to avoid the Global Adjustment charge (which alone covers the \$1,000 fixed avoided cost), and it would receive an Availability Payment in all hours that it chose to make itself available. This provides an advantage to the DR resource over the Generation resources, since the Generation resource can only apply the Availability Payment to cover its \$1,000 fixed avoided cost.

Figure 1.A’: No Energy Payments for DR Resources

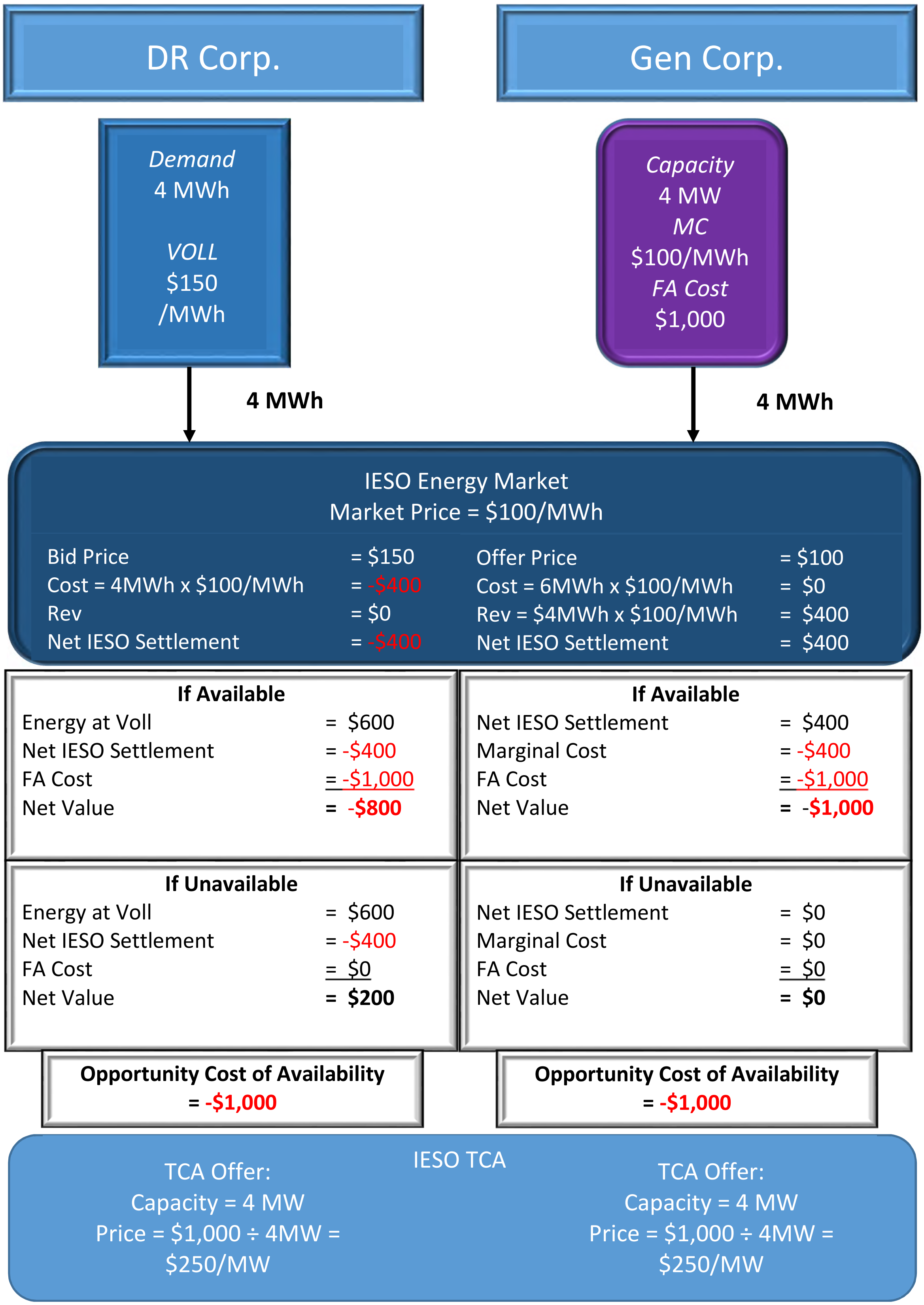
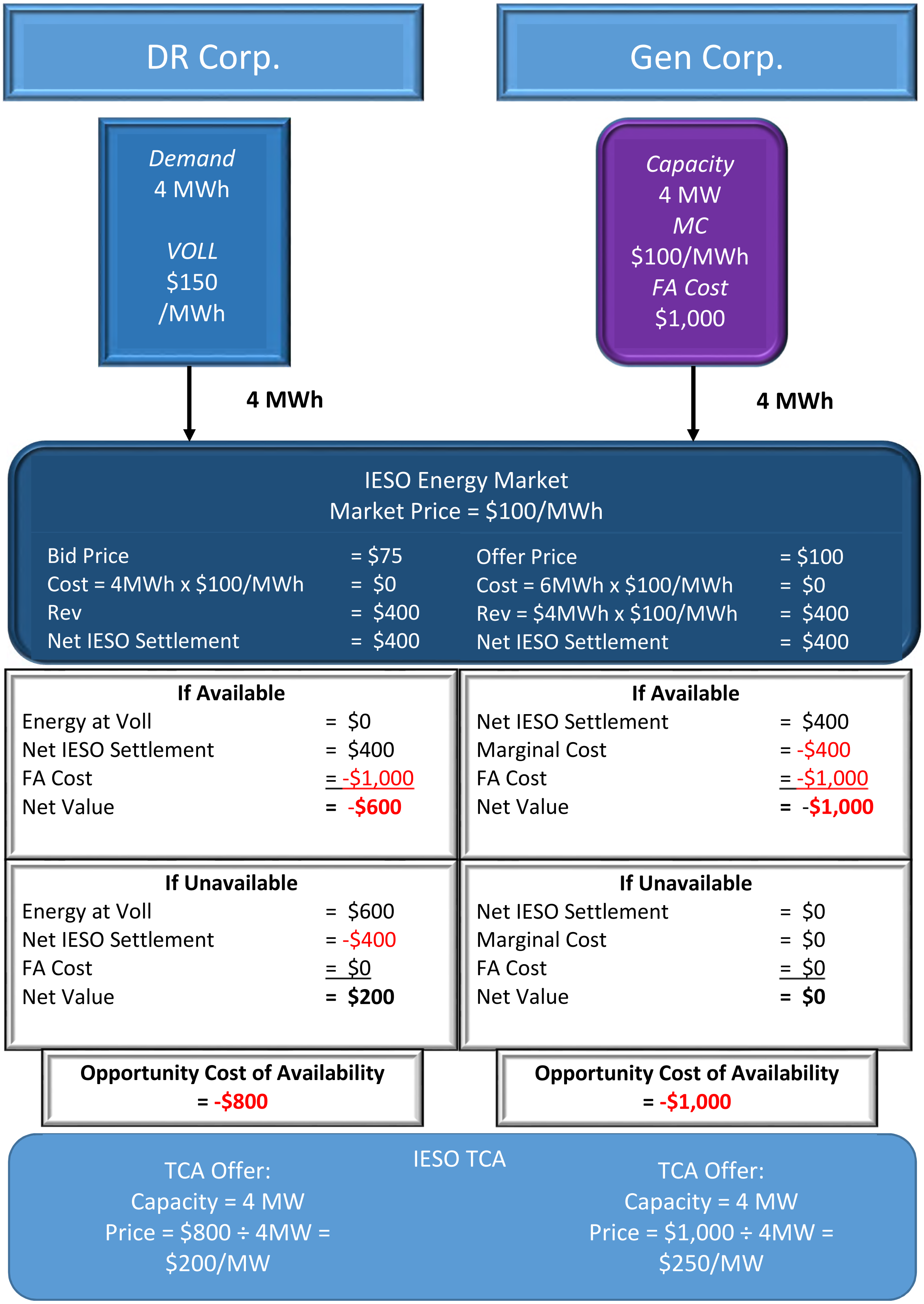


Figure 1.B': Energy Payments for DR Resources



TAB 20

134 FERC ¶ 61,187
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35

[Docket No. RM10-17-000; Order No. 745]

Demand Response Compensation in Organized Wholesale Energy Markets

(Issued March 15, 2011)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: In this Final Rule, the Federal Energy Regulatory Commission (Commission) amends its regulations under the Federal Power Act to ensure that when a demand response resource participating in an organized wholesale energy market administered by a Regional Transmission Organization (RTO) or Independent System Operator (ISO) has the capability to balance supply and demand as an alternative to a generation resource and when dispatch of that demand response resource is cost-effective as determined by the net benefits test described in this rule, that demand response resource must be compensated for the service it provides to the energy market at the market price for energy, referred to as the locational marginal price (LMP). This approach for compensating demand response resources helps to ensure the competitiveness of organized wholesale energy markets and remove barriers to the participation of demand response resources, thus ensuring just and reasonable wholesale rates.

Furthermore, Dr. Kahn argues that paying demand response LMP sets "up an arrangement that treats proffered reductions in demand on a competitive par with positive supplies; but the one is no more a [case of overcompensation] than the other: the one delivers electric power to users at marginal costs—the other—reductions in cost—both at competitively-determined levels."[129]

62. Several other considerations also support this Commission conclusion. In the absence of market power concerns, the Commission does not inquire into the costs or benefits of production for the individual resources participating as supply resources in the organized wholesale electricity markets and will not here, as requested by some commenters, single out demand response resources for adjustments to compensation. The Commission has long held that payment of LMP to supply resources clearing in the day-ahead and real-time energy markets encourages "more efficient supply and demand decisions in both the short run and long run,"[130] notwithstanding the particular costs of production of individual resources. Commenters have not justified why it would be appropriate for the Commission to continue to apply this approach to generation resources yet depart from this approach for demand response resources.

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[129] DR Supporters Aug. 30, 2010 Reply Comments (Kahn Affidavit at 9-10).

[130] See New England Power Pool, 101 FERC ¶ 61,344, at P 35 (2002).

TAB 21

Figure 2: DR Corp. has a higher fixed avoided cost

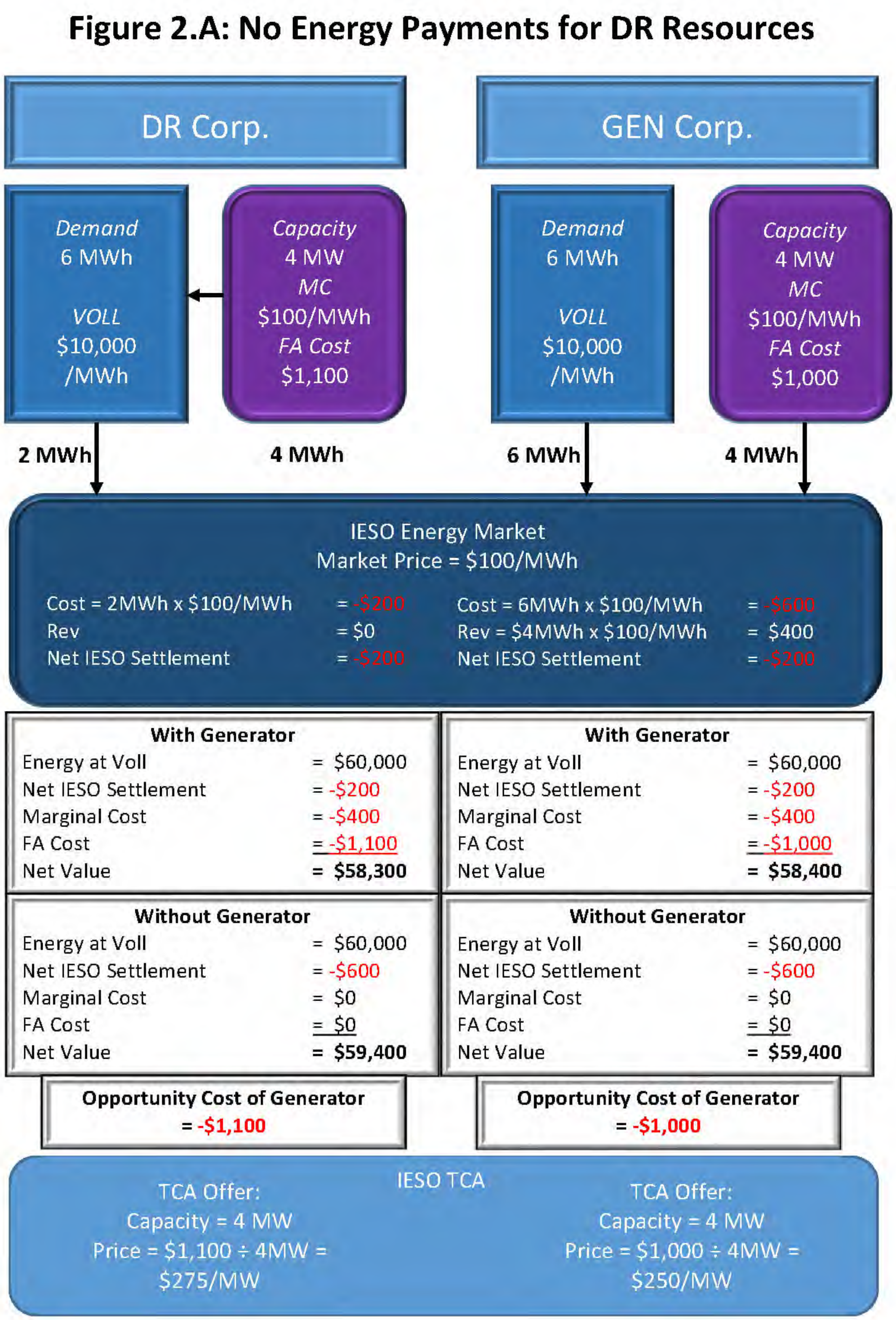


Figure 2.B: Energy Payments for DR Resources

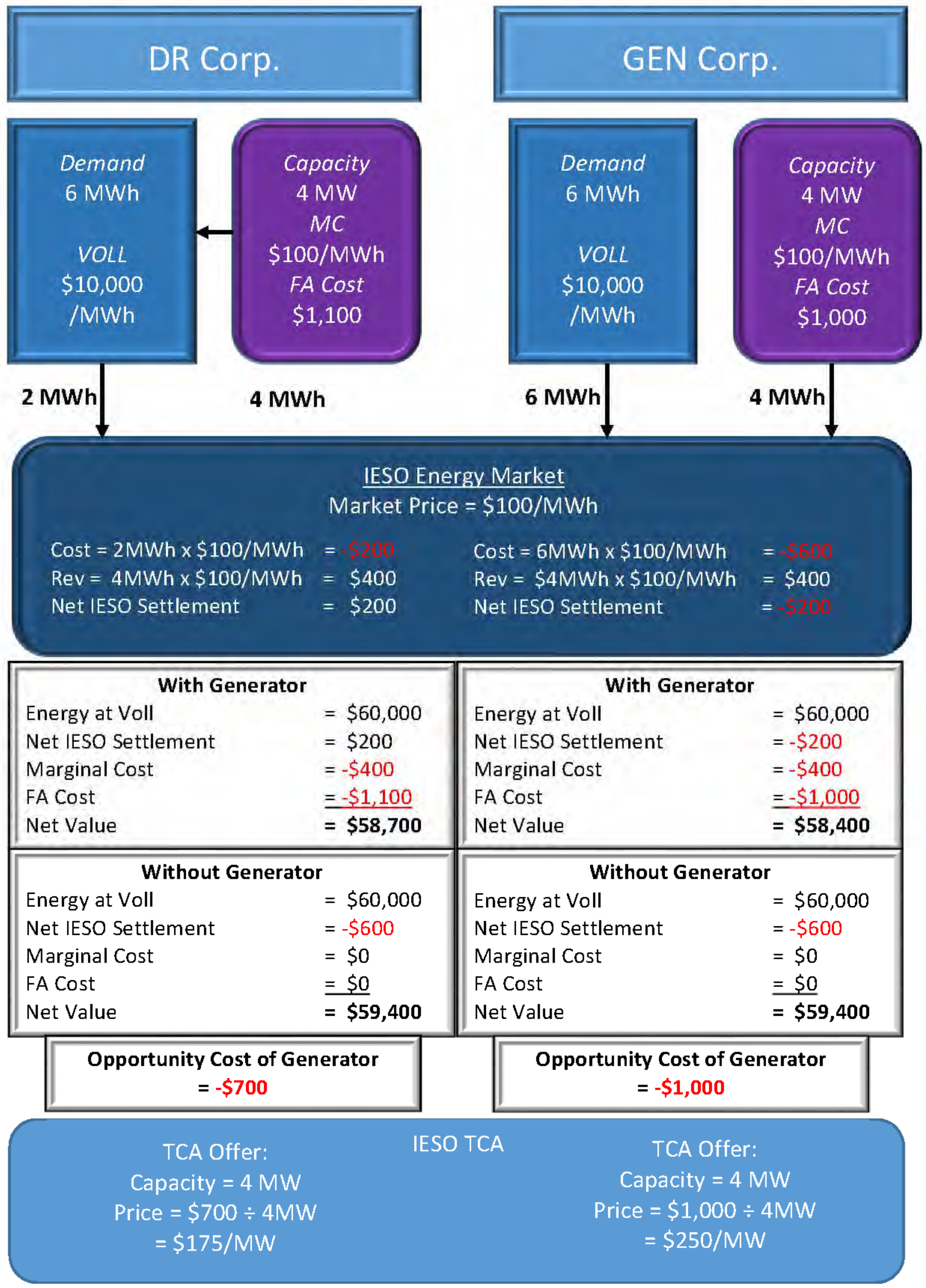


Figure 3: GEN Corp. has a lower marginal generation cost

Figure 3.A: No Energy Payments for DR Resources

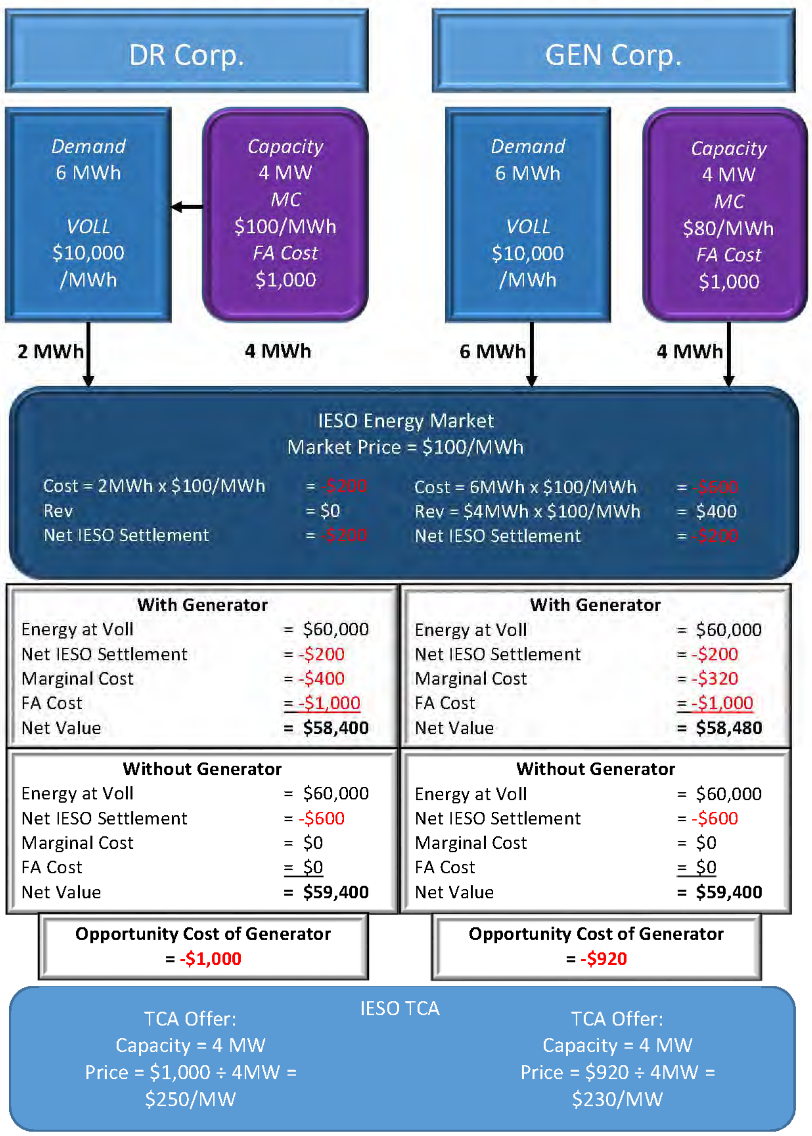
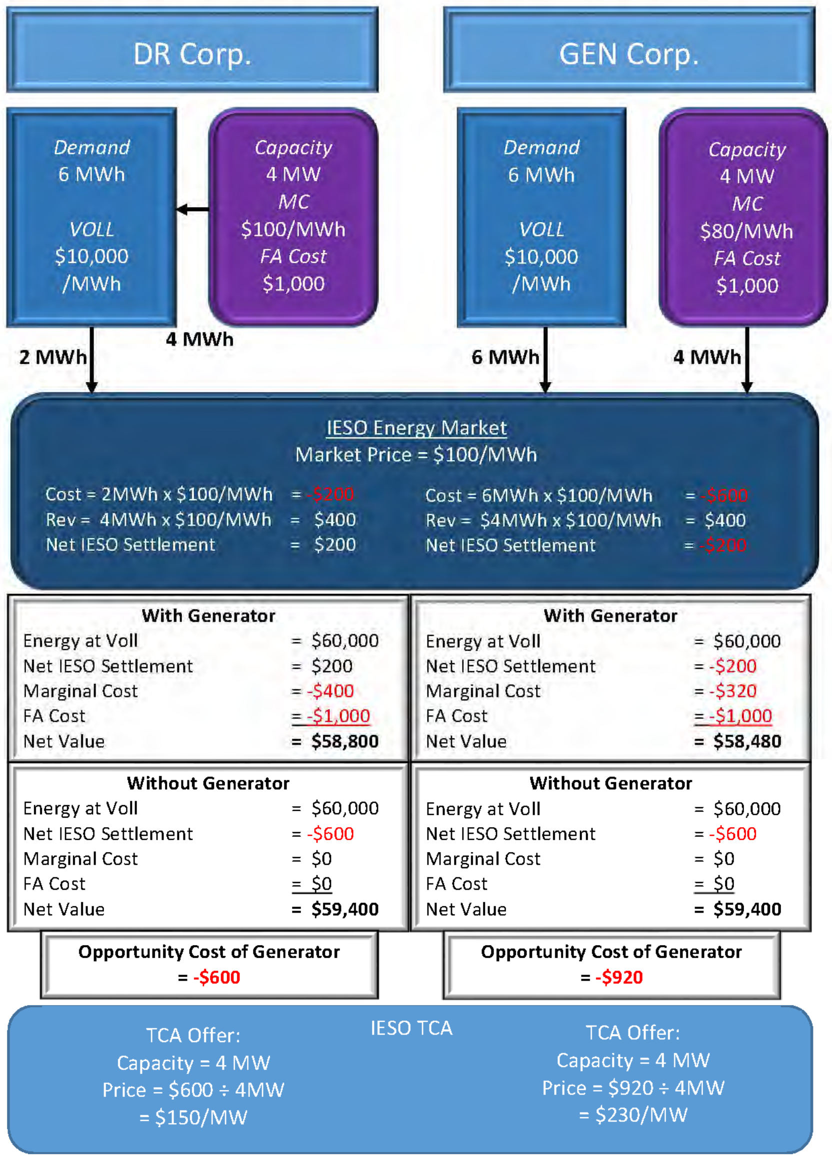


Figure 3.B: Energy Payments for DR Resources



46. In Figure 3, I modify the original example by assuming GEN Corp. has a marginal generation cost of $80/MWh, which is lower than the $100/MWh marginal generation cost of DR Corp. In this case, GEN Corp earns a net revenue equal to the difference between the energy market price of $100/MWh and its marginal generation cost of $80/MWh; a benefit of $20/MWh that it can contribute to the recovery of its fixed avoided cost of making the generator available. It can factor this amount into its capacity offer price. Again, I draw a distinction between the net revenue and the full energy

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the same box? Isn't that the box where the DR resource bids?

DR. RIVARD: In 1 A prime they consume, they actually consume, because the price at that point, being $100 is less than the 150.

MR. MONDROW: Got you.

DR. RIVARD: I think what this is trying to show you is that when you pay the DR resource not to consume, it changes its economics. It now says my opportunity cost is actually different. If I consume, I may forego producing a widget and making some money on it, but I can get paid something to do that. And if it's more money to get paid to do that, suddenly I am kind of in a different business. I am no longer in the widget business. I am in the business of just not consuming.

MR. MONDROW: Well, I'm in the business of optimizing my resources. Sometimes that is not to consume. Sometimes it is to consume and make my widgets. It depends on the market price.

DR. RIVARD: Yeah, that's right. It is it about their personal optimization.

But I think what I am saying is that personal optimization has now changed --

MR. MONDROW: Understood.

DR. RIVARD: -- because of the kind of double benefit that I would say is available.

MR. MONDROW: Okay. And what happens in 1 B prime very bottom line from the market's perspective is the reliability is obtained for fifty dollars less a megawatt, right, from the market's perspective, from the ratepayer's perspective?

DR. RIVARD: Yes. If suppose -- I think that is fair, with the caveat that they offer less. If it turns out that they were the clearing resource, and the price clears at 200 where alternatively they'd have been the clearing resource in the but for case where they weren't paid and it cleared at 250, it is true there is a savings of $50 on the capacity payment, yes.

MR. MONDROW: So the answer is yes?

DR. RIVARD: The answer is yes, sorry.

MR. MONDROW: From the market's perspective, the electricity market.

DR. RIVARD: From the perspective of the amount paid out of the capacity market, that's true. But can I make one follow on point to that?

MR. MONDROW: I have to let you, unfortunately. I would have loved to have stopped there, but yes, please do. It wouldn't be fair.

[laughter]

DR. RIVARD: The alternative is you no longer may have that generator there at 250.

In my example, if they cleared at $200 for the capacity market, you no longer have that generator.

MR. MONDROW: What do you mean you no longer have them? You mean that KCLP, they exit the market?

DR. RIVARD: Yes. Well, they bid 250 for the capacity

payment and they needed that to make themselves available.
MR. MONDROW: Right.
DR. RIVARD: So now they're saying, well, in three years, I am not going to get an availability payment.
MR. MONDROW: But the market price is still $200 lower, right?
DR. RIVARD: Yes, but if I shut down my plant, I avoid a thousand dollars.
MR. MONDROW: But I am saying the market still pays $200 rather than $250 for the capacity. It is too bad that the generator has gone, but the market ~~is~~ still saves money, right.
DR. RIVARD: The capacity payment as a net are lower, what's going to happen to the energy price? That generator is no longer there.
MR. MONDROW: Well, a couple of years from now, there will be a different set of prices, you will send different signals, and we will get investment.
DR. RIVARD: It's possible. But I think what you have done now is when you're looking at the total -- I think what is important here is what is the total cost that consumers are going to pay both for energy and capacity.
MR. MONDROW: Over what period of time?
DR. RIVARD: Well, I think that is a fair question. It depends on what you're evaluating.
But I think, from a market standpoint, what we're trying to do when you're designing markets is result in the lower cost overall of meeting demand, and that includes

both in the short term in terms of energy, and in the long-term in terms of the capacity that is invested.

MR. MONDROW: We are definitely going to talk about what is market is going to achieve after lunch. Thank you, Madam Chair.

MS. SPOEL: We will resume at 1:15.

--- Luncheon recess taken at 12:15 p.m.

--- On resuming at 1:20 p.m.

MS. SPOEL: Please be seated. I was thinking about economics.

[Laughter]

MR. MONDROW: You and me both.

MS. SPOEL: Okay, Mr. Mondrow.

MR. MONDROW: Thank you, Madam Chair. I was also thinking about economics. Hopefully you had more success than I did, but Dr. Rivard, I am going to go back to 1B prime, and I am going to ask one more time, and I am not going to go over, other than this question ground that you ploughed very ably and thoroughly this morning.

But I wonder if you could, and it is probably just me, just tell me, the $75 bid price for DR Corp., is that a derived number? And if so, could you just explain to me, if possible, briefly how that is derived?

DR. RIVARD: Yes. Let me try and do that.

So if DR Corp. buys electricity and uses it to produce widgets, it will receive a value from the sale of that widget at $150 per megawatt-hour, essentially translated. So it is willing to pay up to $150 per megawatt-hour, just

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	Susan Frank	**Member**

we are still puzzled.

MS. FRANK: We will study it over lunch.

DR. RIVARD: Thank you.

MS. SPOEL: Sorry. I keep interrupting your examination in-chief, I apologize.

MS. KRAJEWSKA: It's fine. I think it is really helpful. I think it actually helps with the flow to address these issues as they come up.

Dr. Rivard, I just want to go back to something you started off with in your testimony, which is this idea of generators and demand responses, whether they are functionally equivalent or not.

If you could just elaborate from a kind of economic perspective why they're not maybe functionally equivalent.

DR. RIVARD: I am not sure I would agree with that. I think the point is that a demand response resource that reduces a megawatt of electricity to help balance the load, the supply and demand, is functionally equivalent from a generator that produces a megawatt of electricity to help balance demand.

If we use that as a test for discrimination or to define what is equal to treatment, you might come to the conclusion that they both should be paid for that service.

What I would argue is that's not the appropriate test for measuring discrimination, that I believe the concepts of horizontal and vertical equity are more appropriate, and what my examples do is try and draw that distinction.

MS. KRAJEWSKA: Okay. That concludes my examination

TAB 23

134 FERC ¶ 61,187
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35

[Docket No. RM10-17-000; Order No. 745]

Demand Response Compensation in Organized Wholesale Energy Markets

(Issued March 15, 2011)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: In this Final Rule, the Federal Energy Regulatory Commission (Commission) amends its regulations under the Federal Power Act to ensure that when a demand response resource participating in an organized wholesale energy market administered by a Regional Transmission Organization (RTO) or Independent System Operator (ISO) has the capability to balance supply and demand as an alternative to a generation resource and when dispatch of that demand response resource is cost-effective as determined by the net benefits test described in this rule, that demand response resource must be compensated for the service it provides to the energy market at the market price for energy, referred to as the locational marginal price (LMP). This approach for compensating demand response resources helps to ensure the competitiveness of organized wholesale energy markets and remove barriers to the participation of demand response resources, thus ensuring just and reasonable wholesale rates.

EFFECTIVE DATE: This Final Rule will become effective on **[**INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER**]**. Dates for compliance and other required filings are provided in the Final Rule.

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SUPPLEMENTARY INFORMATION:

a wide range of interests and viewpoints.[42] The Commission subsequently received additional written comments addressing these issues.

2. Comments

a) Capability of Demand Response and Generation Resources to Balance Energy Markets

20. Various commenters address the comparability of demand response and generation resources for purposes of compensation in the organized wholesale energy markets. To begin, numerous commenters address the physical or functional comparability of demand response and generation, agreeing that an increment of generation is comparable to a decrement of load for purposes of balancing supply and demand in the day-ahead and real-time energy markets.[43] Equating generation and demand response resources, Dr. Alfred E. Kahn states:

> [Demand response] is in all essential respects economically equivalent to supply response . . . [so] economic efficiency requires . . . that it should be rewarded with the same LMP that clears the market. Since [demand response] is actually—and not merely metaphorically—equivalent to supply response, economic efficiency requires that it be regarded and rewarded, equivalently, as a resource proffered to system operators, and be treated equivalently to generation in competitive power markets. That is,

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[42] See Sept. 13, 2010 Tr.

[43] DR Supporters Aug. 30, 2010 Comments (Kahn Affidavit at 2); Verso May 13, 2010 Comments at 3-4; Occidental May 13, 2010 Comments at 11; Viridity June 18, 2010 Comments at 5.

reselling energy. They state that the description of demand response as a reselling of energy has been correctly rejected by the Commission in EnergyConnect, where the Commission stated that it was establishing a policy of treating demand response as a service rather than a purchase and sale of electric energy.[70]

31. DR Supporters further argues that, despite claims to the contrary, paying full LMP to demand response providers does not constitute a subsidy for demand response any more than the remunerations of generators for the power that they sell. As Dr. Kahn states:

> Does this plan involve double compensation, as [Dr.] Hogan asserts, at the expense of power generators—of successful bidders promising to induce efficient demand curtailment and of consumers induced to practice it? Certainly not: the decrease in the revenue of the generators is (and consequent savings by consumers are) matched by the savings in their (marginal) costs of generating that power; the successful bidders for the opportunity to induce that consumer response are compensated for the costs of those efforts by the pool, whose (marginal) costs they save by assisting consumers to reduce their purchases.[71]

32. Viridity further disputes Dr. Hogan's argument that payment of LMP for demand response will distort an otherwise optimal market. Viridity posits that such arguments ignore dislocations in the wholesale power markets, the existence of market power that must be mitigated, imperfect information available to customers, barriers to entry and

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[70] DR Supporters Aug. 30, 2010 Reply Comments at 10 (citing EnergyConnect, Inc., 130 FERC ¶ 61,031 at P 30-31 (2010)).

[71] DR Supporters Aug. 30, 2010 Reply Comments, Kahn Affidavit at 10.

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provide the energy.

So in a case of a generator, it is available to produce electricity, or in the case of a demand response resource, it is the ability to reduce consumption from a previous level.

MS. SPOEL: Can I just ask one quick clarifying question? So if the auction is run and there's, say, 20 participants -- I am making all of this up -- say there is 20 participants and they -- each participant bids a price per megawatt. And presumably there will be 20 different or -- there will be 20 individual bids with different prices.

Does the IESO choose the lowest of those and establishes that as the clearing price that everybody has to take? Or how -- or does participant A get paid a different amount than participant B based on how much capacity the IESO requires? Because when you said it establishes a price, I am wondering whether it is a price? Or whether there are several prices? And how that -- maybe you can explain how that works, because I am not entirely sure.

DR. RIVARD: Yes, no, I am happy to do that. And I think it is how you describe it.

So there are 20 --

MS. SPOEL: I asked either/or, so I am not sure how I described it.

DR. RIVARD: It is how you described it I believe in the first case. So you have 20 demand response participants, and they have to determine how much they believe they would need to recover just to make themselves available if ever called upon to reduce their demand.

So they could all submit different prices at which they would say, yes, if I receive at least that I am willing to be available. It is like supply and demand. So the IESO kind of stacks up those capacity offers from lowest to highest, and at the point when those stacked prices intersect with the amount of capacity that the IESO is looking to purchase, that becomes a clearing price.

MS. SPOEL: Oh, okay. Then everybody gets that price? Or they get the price that they have each bid?

DR. RIVARD: Yes. Everybody who is successful that bid below that price receives that clearing price.

MS. SPOEL: Okay. So if I bid $10 and you bid 20 and clearing price -- Ms. Frank bids 30 and the clearing price ends, they would only need the amount that you and I have bid. The price will be 20, because that was the lowest -- that was the sort of maximum price that they had to go to in order to get the capacity they need. So the price will be 20, but I will get 20 as well because, even though I bid 10, I will get actually get 20, because you bid 20, and they need yours as well as mine.

DR. RIVARD: That's correct, yes.

MS. SPOEL: And Ms. Frank won't get anything because she bid 30.

DR. RIVARD: Unfortunately not.

MS. SPOEL: But they don't need hers. They only need -- if I bid 10 megawatts and they need, say, a total of 20 megawatts and we each -- the three of us bid 10, they will take the 20 that are the cheapest?

DR. RIVARD: That's correct.

MS. SPOEL: Then everybody gets the same price for those 20.

DR. RIVARD: Yes.

MS. SPOEL: Okay. All right. That is helpful. I wasn't sure about those kinds of mechanics. Thank you.

MS. KRAJEWSKA: Thank you. And Dr. Rivard, so we talked a little bit about the DRA. What has now changed under the proposed TCA? What is the difference under the proposed amendments?

DR. RIVARD: So the way I would summarize it is the IESO would like to open up the opportunity to sell that availability to either produce or reduce energy to generators, and in particular, a specific type of generator, those who are not currently under a form of contract or regulation.

MS. KRAJEWSKA: And Dr. Rivard, as I understand it, AMPCO's position in this proceeding is that because a generator and a demand response resource under the TCA are going to provide the same type of service, that they should be compensated in the same way.

How do you respond to that proposition?

DR. RIVARD: Right. So from what you said, I interpret that that what AMPCO is advocating for is something consistent with a functionally equivalence test. And if I was to describe that test, it really says what we want to focus on is the end result here.

And so if a demand response resource reduces demand and it balances supply, or a generator produces electricity and it balances supply and demand for the IESO, they're the same, and therefore they should be paid the same amount.

That is essentially the issue that came up in the FERC order 745. So that is one way of looking at equity.

My perspective is that it's kind of a simplistic way at looking at equity. In fact, I think it can lead you to the wrong conclusions.

My preference would be to apply more standard concepts of equity, which is horizontal equity and vertical equity.

And I think I can offer you, if you are willing and up to it, kind of an example of what might distinguish equivalence from horizontal -- and the principles of horizontal and vertical equity.

So I'll take an example that I think we all are familiar with, and that is income tax. So we have a situation where there's two individuals and they make 100,000 each a year. The government needs money to fund social programs, and it can get a dollar from either individual. And from a functional equivalence standpoint, that dollar is the same. It's going to be used in whatever way to help fund the social programs, the government social programs.

When we think of the income tax, we recognize that those two individuals are identical, and that horizontal equity says that we should treat them identically.

in terms of cross-examination efficiency.

So, yes, why don't you ask what you think would be useful to ask now, and then you can have the lunch break to organize yourself.

MR. MONDROW: Thank you very much. And I am not even facetiously impugning what we heard. I think it is very helpful.

MS. SPOEL: We're not taking it that away.

MR. MONDROW: Dr. Rivard, thank you very much. I feel like I am back in -- well, I would never have made it into economics. But had I been in economics, I wish I would have had you as a professor.

[Laughter]

MR. MONDROW: So I want to try to talk about a couple of the concepts, and that will help me over the lunch break to hopefully understand a bit better. I am just going to go in order of my notes here.

When all -- Member Frank asked you -- sorry, it was Chair Spoel who asked you about how the capacity auction clears, and you described that very well. And as I understand it, when the capacity auction clears, when all the capacity auction bidders who are successful get paid their availability payment, their capacity payment, they all get the same unit price. And that is the price at which the auction clears. Is that correct?

DR. RIVARD: Yes.

MR. MONDROW: And is that functional equivalence horizontal equity or vertical equity?

DR. RIVARD: That's a good question. So the IESO designs a market that tries to make sure that it gets a megawatt of reliability that is consistent across any type of resource that provides that megawatt.

To the extent they can deliver on that megawatt, that would be functional equivalency. The IESO assesses that and to make sure that that's the case.

To the extent they're exactly the same, the relevant ways, in terms of their ability to make themselves available, that would be horizontal equity, yes.

MR. MONDROW: But the IESO doesn't check whether they're equally able to make themselves available at equal costs with equal effort. It doesn't assess horizontal equity. The auction settles based on functional equivalence, right?

DR. RIVARD: I think I would agree that the payment is based on the ability to deliver the product, and they do the testing to make sure in advance that whoever offers is capable of delivering that product, yes.

MR. MONDROW: And when the Ontario real-time energy market clears, it clears in a similar fashion; that is, there are bids, and when the last -- when the total amount of bids stacked up from low to high hits what is needed, there is a price, and all of the providers of that energy service get that clearing price, right? There are Out of ~~other~~ market adjustments, but in the energy market that is what happens.

DR. RIVARD: Conceptually that is exactly what happens.

MR. MONDROW: Okay. And again, that would be functional equivalence, not horizontal equity or vertical equity, right?

DR. RIVARD: Yes.

MR. MONDROW: Okay. You talked with Member Frank a bit about market history in search of a silver bullet which we haven't yet found, and maybe we won't find in quite that way, but I did want to come back to that concept for a minute.

If demand response is seeking and continues to seek a more active role in the market, that would be a change, right? Demand today is not the same as demand in 2002. There is different technology, there's a different way of approaching energy services. Would you agree with that?

DR. RIVARD: Certainly things have changed a lot since 2002. I do think there are technologies available that might allow certain participants to be more responsive to a price.

MR. MONDROW: If they invest in those technologies.

DR. RIVARD: If they invest in those -- to the extent a technology investment is required and that technology is available, yes, I think there are differences, technological differences now, that weren't available back then.

MR. MONDROW: And a payment stream of some sort to demand response resources, whether energy or some other administrative price, would impact the calculus for the

TAB 25

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2019-0242**	**AMPCO Motion**

VOLUME:	**1**	
DATE:	**November 25, 2019**	
BEFORE:	**Cathy Spoel**	**Presiding Member**
	Emad Elsayed	**Member**
	Susan Frank	**Member**

And the -- summing up, just to sum up in the interests of time, the question you are being asked is whether LEI agrees or disagrees with Dr. Rivard's assessment of net benefits and economic efficiency. And you stated that, quote:

"LEI's concern is with regards to the fidelity of the price signal and the need for a more nuanced approach to the concept of horizontal equity."

You also state that:

"Dr. Rivard's discussion of horizontal equity is oversimplified."

Can you briefly explain why you -- well, first of all, what the concept of a horizontal equity is and whether you share Dr. Rivard's view and then why you believe his approach is oversimplified and what a more nuanced approach would be, in your opinion.

MR. GOULDING: Thank you.

And I believe that Dr. Rivard's definition is on page 17, paragraph 32 of his affidavit. And I first want to read his definition, and I want to emphasize that we don't disagree with his definition.

The affidavit states:

"Horizontal equity requires that people who are alike in all relevant respects be treated the same. It corresponds to common notions of fair play and non-discrimination."

So I think that the question that arises is in what way are DR participants and generators alike in all relevant respects?

And when we look at the product that is being provided, in theory, if the market rules have been written appropriately, the product should be the same.

Now, when we start thinking about this question of whether there are short-run marginal costs that arise from participating in DR markets, I think that we need to bear in mind the diversity of market participants and the fact that being activated for many is not frictionless. It is not as simple as flipping a switch and bearing no cost in doing so.

And so when we talk about a more nuanced approach, we believe that it is important to explore whether there are actually short-run avoidable costs that are incurred by DR providers, and we believe that if we are going to apply the concept of horizontal equity, that those short-run costs should be recovered.

So this is where we distinguish ourselves a bit from Dr. Rivard's evidence.

MS. DJURDJEVIC: One more question on these IRs, and this is your response to KCLP's interrogatory response 4A, where you respond that -- and I am skipping to the second sentence:

> "With regards to economic efficiency, LEI's concern is with regards to the fidelity of the price signal and the need for a more nuanced approach."

Can you explain your reference to price signal, and statement, and it is important to define what we mean by excessive. But generally speaking, of course, we want the incentive payment to be appropriately calibrated to produce the response that we want.

And if we pay too much we don't get the response that we want. And if we pay too little, then we get also not the response that we want.

MS. KRAJEWSKA: Right. And in this circumstance, if you overcompensate demand response resources, you run the risk of perhaps deterring investment in generation. That is a possibility?

MR. GOULDING: I think that what we have to look at -- you know, I would prefer not to use the words generation or DR at all.

I think that what we're looking for is the right amount to pay for the product that we are trying to consume. And so if we're able to structure the market rules in a way that is technology neutral and allows for fair competition among the resources, that is what we should be striving for.

So I think the question of whether we characterize something as over compensating DR or unfairly favouring generation has to be examined through the lens of are we properly pricing the product that we're trying to consume?

MS. KRAJEWSKA: And, Mr. Goulding, to go back -- as we discussed earlier, in the FERC order 745, how that compensation was determined to be allocated was by providing demand response resources with a payment based on

MR. GOULDING: That's correct, with a caveat, which is you -- it depends, again, on how narrowly we're defining demand response.

So I think that as we look at that we need to make sure that we take into account properly participants in the ICI program, even if they're not directly registered in the DR auctions. But generally speaking, obviously I just stated it, I would agree with that conclusion.

MR. MONDROW: Fair enough. And if you could turn maybe to page -- again in Staff's compendium it's page number 68 of 86. I think in your paper it is actually page 39. And you see the -- sorry, the fifth bullet on the page. It starts with "demand response procured".

And there, as you just corrected me, you're talking about the proportion of demand response, but you were specifically referring to the demand response option as the vehicle in that bullet.

MR. GOULDING: Yes.

MR. MONDROW: Okay. And you do conclude that bullet by saying:

> "Procurement is limited to a small proportion of Ontario's total capacity."

And you are referring there to demand response procurement?

MR. GOULDING: Yes.

MR. MONDROW: Okay, thank you.

And one more question. Do you think that it is conceptually appropriate to pay demand response resources for the energy services they provide to the energy market?

MR. GOULDING: I want to be careful about terminology, in that I believe that it is appropriate for there to be some sort of payment upon activation.

I think that the actual market rule -- you know, I would need to look at how it was configured and whether that is at an Ontario equivalent of locational-based marginal price, whether it is some kind of a two-part bid. My scope was not to come to a conclusion with regards to that, and doing so would require further analysis.

MR. MONDROW: Fair enough. You said earlier in response to one of my friends that market rules should be product base. And I assumed by that you were referring, for example, to energy services as a product. Is that what you meant? Is that an example of the product when you referred to --

MR. GOULDING: Yes. That would be an example generally of the product. I mean, there is many different ways that we can slice and dice that, but, yes, generally.

MR. MONDROW: Understood. Thank you very much. Thank you, Madam Chair.

MS. SPOEL: Thank you, Mr. Mondrow.

Mr. Zacher, are you next, or Mr. Duffy, are you...

MR. DUFFY: Yes, I will take the questions.

MS. SPOEL: Thank you.

CROSS-EXAMINATION BY MR. DUFFY:

MR. DUFFY: Good afternoon, gentlemen. With respect to FERC order 745, you will agree with me that it was to provide extensive analysis on this particular question, so I am just giving you something off the top of my head. It is always a dangerous thing to do.

But as I thought about this throughout the process, I started thinking about short run marginal costs, and that what would be fair is that for DR resources to, at a minimum, be compensated at their short run marginal cost when activated.

Now, that does produce a disconnect and you have to build a whole host of other rules around it, but it gets us away from the discussion of double counting.

So as we've seen, reasonable people can build an argument for the payment of the full locational based marginal pricing as being true equivalents. I have yet to be convinced of that, but I am of the view that some payment reasonably consistent with short run marginal costs is -- for DR, is consist ten with the principles of fairness.

MS. FRANK: So let's go back to that technology-neutral. So you would say -- I understand if you're talking about a load that the marginal cost argument.

So let's go to a generator. Would you also do the marginal cost for the generator?

I am just trying to keep them -- doesn't matter about the technology, they get the same thing?

MR. GOULDING: I agree. And my concern is that generally, we don't like so-called weddy-wig markets because our concern is that they start leading to the same

TAB 26

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2019-0242**	**AMPCO Motion**
VOLUME:	**2**	
DATE:	**November 28, 2019**	
BEFORE:	**Cathy Spoel**	**Presiding Member**
	Emad Elsayed	**Member**
	Susan Frank	**Member**

are asking me is probably considered outside of the scope of the hearing, and I will --

MS. FRANK: Well, I am looking for, you know, how do we avoid the discrimination.

DR. RIVARD: Yeah.

MS. FRANK: So this is all -- I see this as discriminatory treatment if indeed generators are allowed to get recovery for these start-up costs and DR are not. And the only mechanism they have is to inflate their capacity bid. If there's another mechanism, then they're not discriminated against.

DR. RIVARD: That's correct.

MS. FRANK: So I am looking for, how are they not discriminated against?

DR. RIVARD: Yes. I think that is fair. I think the way they're not discriminated against is to be eligible for a cost guarantee very much like the generator is in terms of the start-up.

And so what the IESO is looking to do going forward is to improve the way it makes decisions in advance to start generation by -- through the day-ahead market and what they call the enhanced real-time -- enhanced real-time start-up guarantee. Anyways, a real-time program similar to what they have now.

And what that would do is have generators in advance say how much they need to recover just as a start and provide them a guarantee that if they are scheduled, that if they don't incur -- recover enough revenues in the energy market, that they will at least be compensated as an insurance that they will cover that cost.

I think there is merit in considering if a DR resource has a very similar type of start-up cost when activated, why not allow them to bid that into the market and then compete against generators to decide, well, should the generator start to produce electricity, or should the demand response resource incur this cost to avoid a payment.

MS. FRANK: So that is all about what the future might hold. But today when we look at the rules that were proposed, that we're considering, there isn't a way to avoid this discrimination, is there? Today in what we've got. Just for this narrow piece. Just these...

DR. RIVARD: No, you're right, yeah. Well, I would say that the point that you raise is, I think there's merit to considering that. I would say that for sure.

But the material effect of it is not real. I think that is the question you are getting to.

MS. FRANK: Right, okay, thank you.

MS. SPOEL: Dr. Rivard, I just had one small area and I just want to make sure I understand this. You spent quite a lot of time talking about allocative efficiency, and essentially, if I can try to paraphrase it, that for societal benefit widget-makers should make widgets and generators should generate electricity, generally speaking, that that is a better allocative exercise because if the widget-maker stopped making widgets in order to do demand

TAB 27

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2019-0242**	**AMPCO Motion**
VOLUME:	**3**	
DATE:	**November 29, 2019**	
BEFORE:	**Cathy Spoel**	**Presiding Member**
	Emad Elsayed	**Member**
	Susan Frank	**Member**

In our compendium, Exhibit K 3.2, that's at tab 2. Could you turn that up, please? You'll see the first page behind our tab 2 is just the cover page for the DR stakeholder priorities for 2017.

And if you go to page number 12 -- I think we gave you the whole presentation, but if you go to page number 12, we see the context in which the issue was raised was preparation for future incremental capacity auction.

And then the issue itself is noted following that page at page 19, if you could turn to page 19. And you see point number 14 on page 19? You have to say yes.

MS. TRICKEY: Yes.

MR. MONDROW: Well, you don't have to say yes. You could say no, but you have to say something.

MS. TRICKEY: I'll say something.

MR. MONDROW: Okay, just to be clear. Point number 14 says: "Reinstate utilization payments for DR activations."

I gather, and there's been some evidence on this, that reinstate means there was some previous demand response programs that did include -- granted, not energy payments, but energy payments, some of which you testified about this morning, correct?

MS. TRICKEY: That is correct.

MR. MONDROW: Okay. And the distinction between activation payments and energy payments, as I understand it, is that activation payments when you refer to them are administratively or contractually determined. They are not necessarily what's paid to resources bidding into and clearing the energy market.

MS. TRICKEY: That's correct.

MR. MONDROW: Okay. And if we look at paragraph 45 of your evidence -- so again this is your examination-in-chief compendium -- we see reference there to the final OPA demand response program, the DR3 program, which had contract set activation payments fixed to $200 per megawatt-hour.

That's the program that one of you -- sorry, I forget which one it was -- spoke to earlier this morning, correct?

MS. TRICKEY: That's correct.

MR. MONDROW: Okay. And what was the purpose of those payments?

MS. TRICKEY: The contract structure for those programs was to split the payments for demand response in this program into two pieces. Part of it was an availability payment, and part of it was a fixed activation payment for when those resources were activated.

MR. MONDROW: And that was the $200 per megawatt-hour --

MS. TRICKEY: Correct.

MR. MONDROW: -- the fixed activation payment. And that was intended to compensate the resources for any costs of activation?

MS. TRICKEY: I wasn't part of designing that. I can't say exactly what they were intending. But that is, you know, that's a reasonable assumption to make.

MR. MONDROW: Okay. And at paragraph 46 of your evidence, you talk about the capacity-based demand response or CBDR program, and that's the program that continued the fixed $200 per megawatt-hour utilization payment until expiration of the DR3 contracts?

You talked about that, I think, this morning as well.

MS. TRICKEY: Yeah, that's correct. That was the program or the set of rules that the IESO created so that we could seamlessly transfer the resources that were willing and able to go from a contract structure into a market structure to do that, because the IESO and OPA weren't merged at that time. The IESO had to create a set of market rules that essentially replicated the DR3 program, so we created those rules, called that the capacity-based demand response program.

So it was really the same program, just under a different name, to enable the IESO to operate it at that time under the same contract structure. And again, as I Said, the intent of that was to provide a stable transition from the contract structure to the auction structure.

MR. MONDROW: Could you go to our compendium, please, Exhibit K3.2, tab 3. And you should find behind that tab a copy of a market rule amendment submission form, and if you have that you'll see that it's -- on the first page it was a form submitted by IESO staff, and under part 2 where it says "Title", it says "delete references to the transitional demand response and emergency load reduction programs".

And then if you turn over onto the next page in the box, you see under the heading "background", the first of those programs, the ELRP, which was brought into effect June 20, 2006 as a reliability initiative, gave participants opportunity to receive standby and activation payments to reduce load during emergency periods identified by the IESO.

So -- and by way of context, this market rule amendment was to remove references to those programs, as I understand it from reading it, because they were spent. But it does reveal the trail that this ELRP program also contained both standby and activation payments for demand reduction; will you accept that?

MS. TRICKEY: Yes.

MR. MONDROW: Okay. And the next paragraph refers and starts with the word "similarly". "The transitional demand response program (TDRP)", which I don't think we've talked about yet; is that right?

MS. TRICKEY: Not that I recall.

MR. MONDROW: Okay, me either. And again we see economic assistance was given for voluntarily reducing demand based on market price signals. That's the last part of the sentence.

And it's my understanding that that was -- included activation payments of up to $500 a megawatt-hour; do you know if that's correct by any chance?

MS. TRICKEY: I can't verify that.

MR. MONDROW: Okay. Could I ask you to undertake to verify if there were activation payments for that program and, if so, what the parameters were? I wasn't able to find it.

MR. ZACHER: That's fine.

MR. MONDROW: Thank you.

MS. DJURDJEVIC: That's our first undertaking today, J3.1.

UNDERTAKING NO. J3.1: TO VERIFY IF THERE WERE ACTIVATION PAYMENTS FOR THE TRANSITIONAL DEMAND RESPONSE PROGRAM, AND IF SO, WHAT THE PARAMETERS WERE.

MR. MONDROW: In any event, I think what we have seen over the last few minutes is there has been some history of demand response resource activation payments at the IESO and prior to that the OPA; is that a fair conclusion?

MS. TRICKEY: There have been different structures with -- meant to incent demand response -- or load participants to respond to some sort of activation by the IESO. Each one has its own objectives and goals and structures but, yes, you are correct in that a number of them -- and historically that was a fairly common practice, to provide both -- two types of payments.

MR. MONDROW: And we saw a few minutes ago that in 2017, along with discussions regarding evolution of the demand response auction, the topic was raised again by DR market participants?

MS. TRICKEY: Correct.

MR. MONDROW: And we know that Navigant was engaged in July 2017 and produced their paper, and you have referred to that.

IESO UNDERTAKING J3.1

UNDERTAKING

To verify if there were activation payments for the Transitional Demand Response Program, and if so, what the parameters were

RESPONSE

The objectives of the Transitional Demand Response Program (TDRP), introduced in 2004, were to help market participants overcome specific barriers to demand response in the short-term and increase the level of demand responsiveness in the Ontario electricity market over the medium and long term. The payment for demand response provided through TDRP was based on the three-hour ahead pre-dispatch price to a maximum of $500/MWh.

The parameters were set out in the attached Market Manual Part 5.10: Transitions Demand Response Program (TDRP) issued August 12, 2004.

Demand Response Working Group Meeting Materials

Demand Response Working Group

June 19, 2019

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Meeting Agenda

Time	Agenda Item
9:00am	Welcome
9:05am	DRWG Update
9:10am	Presentation - Revised DRWG 2019 Work Plan
9:40am	Presentation & Discussion - Capacity Obligation Transfer in the TCA
10:00am	Presentation – HDR Resource Testing Results
10:15am	Presentation & Discussion – HDR Resource Testing Proposal
10:35am	Break
10:50am	Presentation & Discussion – Cost Recovery for Out-of-Market Activation Payments - HDR Resources Proposal
11:40am	Presentation & Discussion - Energy Payments for Economic Activation of Demand Response Resources Research Plan
12:10pm	Wrap-Up & Next Steps
12:20pm	Adjourn

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Cost Recovery for Out-of-Market Activation of Hourly DR Resources - Proposal

Demand Response Working Group

June 19, 2019

Purpose

- Discuss a proposal to provide HDR resources cost recovery for out-of-market activations (i.e. testing or emergency activations) consistent with treatment of other resource types

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HDR Activations

- There are two ways an HDR resource can be activated

In-Market	Out of Market
• Based on market economics • HDR energy bids intended to reflect the maximum they are willing to consume at given price • HDR will be “activated” when the price for electricity is greater than their willingness to consume	• HDR resources can be activated outside of market economics to respond to a: 1. Capacity test, or 2. Emergency Control Action • HDR will be activated even if the electricity price is lower than their bid price

- Observed bid prices and stakeholder feedback indicate that activation costs (explicit and opportunity) can be significant for HDR resources

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Out Of Market Costs

- When other resource types (dispatchable load, generator, import) are dispatched out-of-market they are eligible for some form of "make-whole-payment"
  - A make-whole payment may apply when a participant faces a shortfall between their resource bid/offer price and the revenue earned through market clearing prices
  - The payment restores the participant to the financial situation they would have been in as implied by their bids/offers
- HDR resources do not receive a make-whole payment for out of market activations
- These costs may be reflected in their capacity offers potentially increasing the cost of the capacity

Implications for ICA and TCA Participation

- In the Demand Response Auction, HDR participants could reflect the expected cost of out-of-market activations in DR Auction offer prices
  - Since the DR Auction was for DR only, all HDR resources were impacted equally
- In the context of the proposed capacity auctions, where HDR will be competing against other resource types, how these costs are recovered will potentially impact market efficiency

Proposal

- IESO's initial assessment concludes that providing HDR resources cost recovery for out-of-market activations is:
  - appropriate as testing or emergency activations can occur at a price below bid price of an HDR
  - consistent with energy market and existing design treatment of other resources (including dispatchable load)

Potential Design Considerations/Issues

IESO requests feedback from stakeholders on potential design considerations, including:

- Most appropriate method for determining compensation; for example:
  - Using energy bids as representative costs
  - Historical precedents, such as CBDR activation payments
  - Identify costs on individual or type of resource basis
- Undue administrative burden of potential options
- Operational impacts on market participants, for example measurement data requirements
- Other considerations that should be assessed

Next Steps/Timelines

- Stakeholders to provide feedback on concept and design considerations by July 5
- Work with stakeholders on design details of this concept and initiate market rule amendment process during Q3, 2019
- Timeline
  - Implement changes for May 2020 TCA obligation period to enable DR participants to incorporate change to offers in December TCA

TAB 28

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2018 Long-Term Reliability Assessment

December 2018

NPCC-Ontario

The Anticipated Reserve Margin falls below the Reference Margin level in the mid-2020s to 18.6 percent (**Figure 1.5**). This is driven by nuclear retirements, the nuclear refurbishment program, and the assumption that certain generation resources will not be available once their generation contracts have expired. That said, there are uncertainties in the projections that could see the shortfall grow or shrink. As a result, the Independent Electricity Service Operator (IESO) will continue to update and refine its forecasts to gain more certainty about the size of the gap. The development of a capacity auction is underway as a means to acquire any necessary resources for 2023, and IESO expects that there are sufficient resources that can be developed with a three-year lead time to meet at 2023 resource gap.

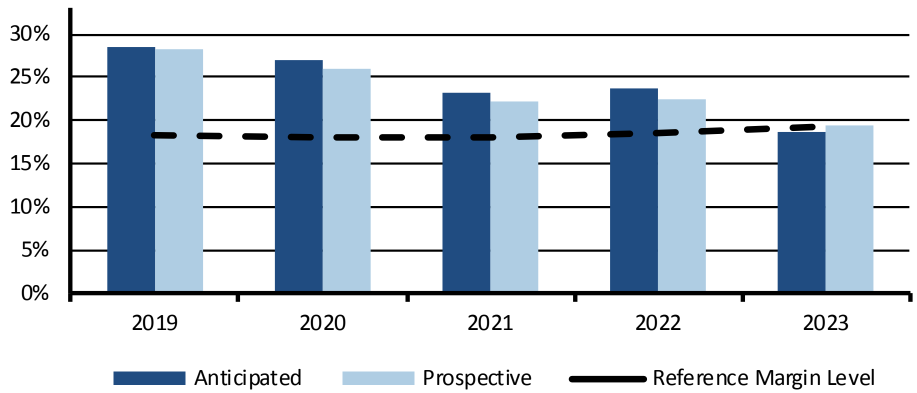

Figure 1.5: Ontario 5-year Projected Reserve Margins through 2023 (Anticipated and Prospective Reserve Margins)

How NERC Defines Future Capacity Supply

Tier 1: Unit that meets at least one of the following guidelines (with consideration for an area's planning processes):

- Construction complete (not in commercial operation)
- Under construction
- Signed/approved Interconnection Service Agreement (ISA)
- Signed/approved Power purchase agreement (PPA) has been approved
- Signed/approved Interconnection Construction Service Agreement (CSA)
- Signed/approved Wholesale Market Participant Agreement (WMPA)
- Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to Vertically Integrated Entities)

Tier 2: Unit that meets at least one of the following guidelines (with consideration for an area's planning processes)2:

- Signed/approved Completion of a feasibility study
- Signed/approved Completion of a system impact study
- Signed/approved Completion of a facilities study
- Requested Interconnection Service Agreement
- Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs)

Tier 3: Units in an interconnection queue that do not meet the Tier 2 requirement

The following regional assessments were developed based on data and narrative information collected by NERC from the REs on an assessment area basis. The RAS, at the direction of NERC's PC, supported the development of this assessment through a comprehensive and transparent peer review process that leveraged the knowledge and experience of system planners, RAS members, NERC staff, and other subject matter experts. This peer review process promotes the accuracy and completeness of all data and information. A summary of the key data is provided in **Table D.1**.

Table D.1: Summary of 2023 Peak Projections by Assessment Area and Interconnection

	Peak Demand (MW)	Annual Net Energy for Load (GWh)	Net Transfers (MW)	Anticipated Capacity Resources	Anticipated Reserve Margin
FRCC	47,144	241,710	1,178	59,083	25.33%
MISO	120,424	679,319	556	140,704	16.84%
MRO-Manitoba	4,336	24,900	125	6,270	44.60%
MRO-Sask	3,977	27,117	100	4,784	20.29%
NPCC-Maritimes	5,245	27,106	0	6,737	28.45%
NPCC-New England	24,317	117,039	81	31,364	28.98%
NPCC-New York	31,414	153,593	1,942	38,558	22.74%
NPCC-Ontario	21,589	133,215	0	25,456	18.62%
PJM	145,885	816,817	0	196,261	34.53%
SERC-E	43,134	218,138	25	52,397	21.48%
SERC-N	40,296	213,861	-952	50,201	24.58%
SERC-SE	46,662	251,006	-1,744	62,418	33.77%
SPP	53,485	271,312	-81	66,935	25.15%
EASTERN INTERCONNECTION	587,908	3,175,132	1,230	741,322	N/A
QUEBEC INTERCONNECTION	37,473	191,567	-145	42,290	12.86%
TEXAS INTERCONNECTION	78,258	422,216	7	85,000	8.62%
WECC-AB	12,321	88,253	0	15,134	22.83%
WECC-BC	12,186	67,068	0	13,920	14.23%
WECC-CAMX	50,201	270,617	0	62,504	24.51%
WECC-NWPP US	50,141	298,914	3,300	62,086	23.82%
WECC-RMRG	13,202	72,988	0	15,993	21.14%
WECC-SRSG	25,712	117,962	0	31,085	20.90%
WESTERN INTERCONNECTION	163,763	915,802	3,300	200,721	N/A

IESO UNDERTAKING J3.2

UNDERTAKING

To calculate a reserve margin for 2023, if the forecast 4,000-plus capacity gap is not reached

RESPONSE

The TCA is intended to assist the IESO to meet its minimum reliability requirements in accordance with NERC reliability standards. If the IESO did not obtain the approximately 4,000-plus megawatts required to meet the 2023 capacity gap through the TCA or any other means the resulting 2023 reserve margin would be approximately -5% and the IESO would not be able to meet the forecast 2023 demand.

TAB 29

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2019-0242**	**AMPCO Motion**

VOLUME:	**3**	
DATE:	**November 29, 2019**	
BEFORE:	**Cathy Spoel**	**Presiding Member**
	Emad Elsayed	**Member**
	Susan Frank	**Member**

bullet says:

"In the context of the proposed capacity auctions, where HDR will be competing against other resources types, how these costs..."

And we are talking about the out-of-market activation costs:

"...are recovered will potentially impact market efficiency."

Do you agree with that statement?

MS. TRICKEY: Yes, I do.

MR. MONDROW: Okay. Mr. Short, on Monday Mr. Barz on behalf of APPrO took Mr. Anderson to a graph showing HDR performance testing failure rates. Are you familiar with that issue generally?

MR. SHORT: We're familiar, but actually, Ms. Trickey's probably more familiar.

MR. MONDROW: Oh, okay. That's fine. Nice punt.

MR. SHORT: If that's okay.

MR. MONDROW: Yes, that's fine. Ms. Trickey, you should go to -- sorry, I am getting punchy -- can you go to tab 10 of our compendium, Exhibit K3.2. And this is yet another set of minutes. This is the demand response working group meeting notes June 19th, 2019, and I am going to look at page 4 at the bottom.

And at page 4 at the bottom there's a comment italicized, which I think means it's an IESO -- recording of an IESO comment:

"The IESO acknowledges that HDR is a new resource "and that there is an opportunity for the IESO to better understand their level of performance and what is holding HDR resources from passing tests, whether it is the testing methodology or the capabilities of the resource, the IESO is open to further discussions."

Would you agree with that statement, Ms. Trickey?

MS. TRICKEY: Yes.

MR. MONDROW: Thanks. And one last question for you, Mr. Short, please. If you could look with me at tab 10 of our compendium. This is another excerpt from the affidavit of Dr. Rivard. I want to read to you paragraph 91.

MR. SHORT: You mean tab 11?

MR. MONDROW: Oh, did I say tab 10? I'm sorry, tab 11, yes, thank you, last tab, paragraph 91.

Dr. Rivard says:

"The presence of the global adjustment means that the FERC net benefits test will rarely if ever be satisfied in Ontario. Furthermore, there would be significant complications for the IESO to implement the net benefits test in Ontario due to the global adjustment. In my opinion, the evidence shows that there is no net benefit -- nice little play on words -- to even further studying the merits of the application of the net benefits test in Ontario."

So having received Dr. Rivard's evidence, Mr. Short, and read it, are you now going to abandon that project?