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

COMPENDIUM FOR THE IESO'S CROSS-EXAMINATION OF COLIN ANDERSON

November 24, 2019

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[1] Documents in this compendium that are not included in the evidentiary record were provided to AMPCO counsel November 24, 2019.

TAB	DOCUMENT DESCRIPTION	SOURCE
	Paper, dated December 18, 2017	Tab 8
9.	Revised Affidavit of Brian Rivard (Excerpts)	Revised Affidavit of Brian Rivard, sworn November 21, 2019
10.	IESO, Energy Payments for Economic Activation of DR Resources, dated October 10, 2019	Evidence of the Independent Electricity System Operator, dated November 8, 2019, Tab 24
11.	AMPCO Submission, IESO Stakeholder Engagement on Energy Payment for Economic Activation of DR Resources, dated October 25, 2019	N/A
12.	Market Surveillance Panel, Energy Payments for Economic Activation of Demand Response Resources, Comments on the Stakeholder Engagement Plan Presented on October 10, 2019	N/A
13.	IESO Evidence (Excerpts)	Evidence of the IESO dated November 8, 2019

TAB 1

EB-2019-__________

ONTARIO ENERGY BOARD

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO

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

NOTICE OF APPEAL

Nature of the Appeal and Relief Sought

1. The Association of Major Power Consumers in Ontario (AMPCO) applies to the Board for review of the Independent Electricity System Operator's (IESO) amendments of the Ontario Electricity Market Rules (Market Rules) for implementation of a transitional capacity auction (TCA).

2. On September 5th, 2019 the IESO published, pursuant to *Electricity Act, 1998* (*EL Act*) section 33(1), a package of Market Rule amendments[1] (the Amendments) to facilitate expansion of the existing Demand Response Auction (DRA) platform that has been operative in the IESO Administered Market (IAM) since 2015 into a Transitional Capacity Auction (TCA) platform. The Amendments will allow electricity generators to participate in future capacity auctions alongside Demand Response (DR) resources.

3. Generators receive payments for energy services provided to the IAM. DR resources do not (though the IESO has recently indicated that it intends to review the issue of DR resource eligibility for energy payments for services that they provide to the IAM).

4. The effect of implementing the Amendments to broaden the DRA to a TCA without first addressing the inequity in treatment between generation resources and DR resources in

[1] MR-00439-R00-R05.

the IAM energy market is to unjustly discriminate against DR resources, and in favour of generation resources. This is because the Amendments would allow the latter to effectively and unfairly displace the former in the capacity auction platform which was developed for DR resources and through which such resources have been successfully and competitively participating in the IAM since 2015.

5. AMPCO seeks an order from the Board revoking the Amendments effective the date of the Board's decision herein, and referring the Amendments back to the IESO for further consideration, all pursuant to section 33(9) of the *EL Act*.

6. The first TCA facilitated by the Amendments is currently scheduled for early December, 2019. The Amendments were passed in order to allow the first TCA to proceed. Should the first TCA proceed prior to determination by the Board of this application, generators that participate in the new TCA will be provided with an unfair competitive advantage, and DR resources which have historically participated actively and effectively in the DRA will be unduly and unjustly disadvantaged and potentially irreparably harmed.

7. AMPCO will thus also seek an order of the Board, by way of a motion pursuant to *EL Act* sections 33(7) and 33(8) and Rule 8 of the Board's *Rules of Practice and Procedure* (*Rules*), staying the operation of the Amendments pending completion of the Board's review of the Amendments.

8. AMPCO further relies on section 19(4) of the *Ontario Energy Board Act*, 1998, S.O. 1998, c. 15, Sched. B (*OEB Act*), and Rule 17 of the OEB's *Rules*.

Summary of the Grounds of the Appeal

9. The Amendments adopt rules to implement the first phase of a TCA. The IESO explains that Phase 1 of the TCA, *"enables non-committed dispatchable generators to participate in the TCA alongside dispatchable loads and hourly demand response resources. The*

TCA represents an evolution of the demand response auction into a more competitive capacity acquisition mechanism."[2]

10. The Phase 1 December, 2019 TCA was initially proposed as a first step towards transition to an Incremental Capacity Auction (ICA) to be implemented in 2022 in order to address what had been an identified need for capacity following that date. In July 2019 the IESO announced suspension of work on the ICA in light of an updated forecast indicating sufficient baseload and other resources to ensure reliability for the foreseeable future[3]. As such, the first TCA will simply be the first in potentially a series of capacity auction evolutionary steps without any defined end state or particular timing need.

11. While the IESO has indicated that it will address the issue of compensation of DR resources for the value that they provide to the IAM, resolution of this issue is not anticipated prior to the proposed December 2019 implementation of TCA Phase 1. Commandeering the current DRA to a broader auction platform without first addressing the competitive position of DR resources *vis a vis* generators will unnecessarily damage the existing, highly successful DRA market mechanism, which would be unfair to DR resources and counterproductive to robust evolution of the Ontario electricity market.

12. Without ensuring just and reasonable compensation to DR resources, on a comparable basis with other resources which bring similar value to the IAM, the TCA could result in replacement of one set of capacity providing resources with another. This would not enhance competition, but it may well stifle it.

13. The IESO's proposal for developing a broadened capacity auction is part of its overall Market Renewal Program (MRP). The overall objective of the MRP is to encourage and enhance competition[4]:

> *Creating a stable and efficient marketplace that produces value for consumers involves encouraging competition and innovation among suppliers – and is the catalyst behind initiatives to resolve long-standing market design issues.*

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[2] IESO Memorandum to the Board of Directors of the IESO, from Michael Lyle, Vice President, Legal Resources and Corporate Governance Chair, IESO Technical Panel, dated August 20, 2019 re: Recommendation from the Technical Panel on Market Rule Amendment Proposal.
[3] IESO, Energy Payments for Economic Activation of Demand Response Resources, September 25, 2019.
[4] IESO Transitional Capacity Auction, Phase 1 Design Document, April 11, 2019, page 1, 2nd paragraph.

14. Requiring DR resources to compete with generators in a TCA prior to resolution of the eligibility of DR resources for energy payments would:

a. Undermine competition and market confidence, a result inimical to the IESO's objectives for the capacity auction program and its MRP in general.

b. Introduce unjust discrimination against DR resources in the expanded auction program by requiring them to compete with generators prior to resolution of the eligibility of such resources for energy payments.

15. Because they discriminate against DR resources and are likely to stifle (not enhance) competition, the Amendments are not only unjustly discriminatory, they are also inconsistent with various of the *EL Act*'s purposes, including:

a. encouraging electricity conservation and the efficient use of electricity in a manner consistent with the policies of the Government of Ontario;

b. facilitating load management in a manner consistent with the policies of the Government of Ontario;

c. promoting 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;

d. protecting the interests of consumers with respect to prices and reliability of electricity service; and

e. promoting economic efficiency and sustainability in the generation, transmission, distribution and sale of electricity.

16. Pursuant to subsection 33(9) of the *EL Act*, the Board must revoke and refer back to IESO amendments to Market Rules that are: (i) inconsistent with the purposes of the *EL Act*, or (ii) unjustly discriminatory against a market participant or class thereof. Because the Amendment is both inconsistent with the *EL Act*'s purposes and unjustly discriminatory to DR Resources, the Board must exercise that power in this case.

Background to the Appeal

A. Historical Demand Response Auctions.

17. DR is the changing of electricity consumption patterns by end use consumers in response to market prices.[5]

18. Since 2015 the IESO has held annual DRAs to acquire DR capacity from market participants that are able to provide that capacity to the market in exchange for an availability payment (which is for present purposes essentially a "capacity payment" - i.e. a payment to ensure that capacity is available to supply energy services as and when called upon).

19. Four successful DRAs have been held in Ontario, the most recent in December 2018. The IESO's report on the most recent DRA underscores the success of the DRA program:

> *This year, 38 organizations were registered as auction participants, the highest number since the auction began in 2015. The successful proponents included four new participants who represent a mix of commercial and industrial consumers.*
>
> *The average annual clearing price for availability payments of $52,810/MW represents a 30% decrease from last year, and a 42% decrease since the first auction in 2015. The auction cleared 818 megawatts (MW) for the 2019 summer commitment period and 854 MW for the 2019/2020 winter commitment period.*
>
> *Moving in to its fourth year, the auction has been established as a valuable and reliable tool for the IESO to secure capacity on the system. Decreasing prices year-over-year demonstrates the ongoing maturity of the demand response market as more consumers participate and competition increases. Lower capacity prices benefit all Ontario consumers, while auction participants benefit by offsetting their energy costs and improving their competitiveness.*
>
> *As the electricity system moves towards competitive electricity auctions under IESO's Market Renewal project, the participation of consumers providing demand response will increase competition leading to overall lower prices for Ontario consumers.*[6]

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[5] IESO Market Manual, Part 12.0: Demand Response Auction, Issue 6.0, page 4, paragraph 1.
[6] IESO, IESO Announces Results of Demand Response Auction, December 23, 2018.

B. Transition to TCA Without Addressing Compensation for DR Resources Inimical to IESO Objectives and to *EL Act*'s Purposes.

20. Starting in December, 2019 the IESO intends to "transition" the DRA into a broader auction by opening participation to other resources. The TCA will permit non-committed dispatchable generators to participate in the auction alongside dispatchable loads and hourly demand response resources.

21. Generation resources, unlike DR resources, have other revenue opportunities in the IAM, including payments for energy services provided. DR resources do not currently have commensurate revenue opportunities for the energy services which they provide to the market.

22. If the TCA is implemented now (through the Amendments), generators will bid into capacity auctions taking 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. [7]

23. As long as this is the case, commandeering the currently successful DRA into a TCA will not broaden the existing auction platform, it will only result in driving the DR resources that have successfully participated in that DRA out of the fledgling IESO capacity market, and replacing one set of capacity auction participants (DR) with another (generators). This would actually be a step backward in evolution of the IAM, not a step forward.

24. Requiring DR resources to compete against generators without resolving the comparative value of DR resources and generation resources in the energy market, and how to justly and reasonably compensate the former in a manner comparable to the latter, would undermine the current success of the DRA and handicap DR resources from successfully competing within their own existing market platform. This result is contrary to various of the *EL Act*'s purposes, including:

[7] Energy payments avoided by the load are not economically equivalent to energy payments for provision of demand reduction to the market, and are not adequately compensatory for the value provided by DR resources to the energy market: 134 FERC ¶ 61,187, 18 CFR part 35, Docket No. RM10-17-000; Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets*, March 15, 2011, paragraph 62.

a. encouraging electricity conservation and the efficient use of electricity in a manner consistent with the policies of the Government of Ontario;

b. facilitating load management in a manner consistent with the policies of the Government of Ontario;

c. promoting 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;

d. protecting the interests of consumers with respect to prices and reliability of electricity service; and

e. promoting economic efficiency and sustainability in the generation, transmission, distribution and sale of electricity.

25. This result is also inimical to the IESO's own objectives of enhancing competition for the benefit of consumers.

26. As noted above, the overall objective of the IESO's MRP is to encourage and enhance competition[8]:

> *Creating a stable and efficient marketplace that produces value for consumers involves encouraging competition and innovation among suppliers – and is the catalyst behind initiatives to resolve long-standing market design issues."*

27. The IESO's proposal to evolve the DRA into a broader based capacity auction is to the same end[9]:

> *The ICA will help us to prepare for [a future period of capacity requirement] by allowing more resource types to compete to provide future capacity, enabling the IESO to flexibly meet the province's adequacy needs.*

28. The success of a broadened capacity auction hinges on expanding participation in competition for the provision of capacity:

> *One of the advantages of the ICA is that all eligible sources of capacity – new and existing, on both the supply and demand sides – compete with each other, regardless of resource type. …From the perspective of meeting adequacy needs, there is no functional difference between a megawatt of power from an electricity*

[8] IESO Transitional Capacity Auction: Phase I Design Document, April 11, 2019, page 1.
[9] IESO *Incremental Capacity Auction High-Level Design: Executive Summary*, March 2019, page 1, last paragraph.

generating facility and a megawatt of reduced consumption from demand response. [10]

29. The TCA would start with the DRA, and add non-committed dispatchable generators as eligible capacity auction participants. The IESO's stated intent in so doing is to *"enable competition between additional resource types"*.[11]

30. At the same time the IESO has acknowledged concerns that there are barriers to DR participation in the IESO markets, and that one of these barriers is the unavailability to DR resources of energy payments.[12]

31. The IESO proposes to study the introduction of energy payments for DR resources (i.e. to determine *"whether there is a net benefit to electricity ratepayers if DR resources are compensated with energy payments for economic activations"*). The study proposed is to be concluded *"before the end of 2020"*, with a next step proposed to be to *"[o]btain input from stakeholders on the approach to conducting the analysis required to make this determination"*.[13]

32. Requiring DR resources to compete against generators without resolving the comparative value of DR resources and generation resources in the energy market, and how to justly and reasonably compensate the former in a manner comparable to the latter, would undermine the current success of the DRA and handicap DR resources from successfully competing within their own existing market platform.

33. Requiring DR resources to compete with generators in a TCA prior to resolution of the eligibility of DR resources for energy payments would:

    a. Undermine competition and market confidence, a result inimical to the IESO's objectives for the capacity auction program and its MRP in general.

    b. Introduce undue discrimination against DR resources in the expanded auction program by requiring them to compete with generators prior to resolution of their eligibility for energy payments.

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[10] IESO *Incremental Capacity Auction High-Level Design: Executive Summary*, March 2019, page 3, 3rd paragraph.
[11] *Transitional Capacity Auction Phase I Design Document*, April 11, 2019, p.2, para. 8.
[12] IESO Demand Response Working Group Meeting Materials, June 19, 2019, pages 54 *et seq.*
[13] IESO Demand Response Working Group Meeting Materials, June 19, 2019, page 7.

(The IESO has recently recognized just this sort of issue in respect of DR compensation for out of market (i.e. testing or emergency) Hourly DR resource activations.[14])

34. Premature introduction of a TCA such that it undermines the ability of DR resources to compete in Ontario's competitive electricity market would be a <u>regressive</u> step in the quest for enhanced competition and innovation.

35. Commandeering the current DRA to a broader auction platform without first addressing the competitive position of DR resources *vis a vis* generators and other sources of capacity would unnecessarily damage a highly successful existing market mechanism, which would be unfair to DR resources, counterproductive to robust evolution of the Ontario electricity market, and irresponsible on the part of the IESO.

C. Failing to Compensate DR Resources is Unjust and Unreasonable.

36. It has been definitively recognized that DR resources can provide electricity wholesale market energy services, and that failure to compensate DR resources for such services is unjust and unreasonable. In a Final Rule issued in March, 2011 the United States Federal Energy Regulatory Commission (FERC) determined that:[15]

> *… when a demand response resource participating in an organized wholesale energy market… 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… that demand response resource must be compensated for the service it provides to the energy market at the market price for energy… 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.*

37. In the course of its consideration of the equivalency of DR resources and generation resources in providing energy services, the importance of recognizing and compensating this equivalency appropriately, and the importance of thus reducing barriers to DR

[14] IESO Demand Response Working Group Meeting Materials, June 19, 2019, pages 36 *et seq*.
[15] 134 FERC ¶ 61,187, 18 CFR part 35, Docket No. RM10-17-000; Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets*, March 15, 2011, page 1.

participation in wholesale markets, FERC cited an earlier order which included a finding that[16]:

> *A market functions effectively only when both supply and demand can meaningfully participate, and barriers to demand response limit the meaningful participation of demand in electricity markets.*

38. FERC went on to find that:

> *Removing barriers to demand response will lead to increased levels of investment in and thereby participation of demand response resources (and help limit potential generator market power), moving prices closer to the levels that would result if all demand could respond to the marginal cost of energy.*[17]
>
> *…*
>
> *In Order No. 719, the Commission found that allowing demand response to bid into organized wholesale energy markets "expands the amount of resources available to the market, increases competition, helps reduce prices to consumers and enhances reliability."*[18]

39. In its rulemaking deliberations FERC also considered arguments that DR resources are "compensated" by avoiding energy costs when responding to requests to curtail consumption, and accordingly paying such resources for energy thereby effectively supplied would amount to double compensation. On these arguments FERC found as follows:[19] [emphasis in original]

> *Furthermore, Dr. [Alfred E.] Kahn argues that paying demand response [marginal price] sets "up an arrangement that treats proffered reductions in demand on a competitive par with positive supplies; but one is no more a [case of overcompensation*] than the other: the one delivers electric power to users at marginal costs – the other – <u>reductions in cost</u> – both at competitively-determined levels [*Insert in original].*
>
> *… 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 [marginal price] to supply resources clearing the day-ahead and real-time energy markets encourages "more efficient supply and demand decisions in both the short*

[16] Ibid, paragraph 57, citing FERC Order No. 719.
[17] Ibid, paragraph 59.
[18] Ibid, paragraph 61.
[19] Ibid, paragraph 62.

run and long run," 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.

40. FERC also recognized in its rule making findings the interrelationship between just and reasonable compensation to DR resources in energy markets and the fairness of associated capacity markets. FERC noted *"how the increased participation by demand resources [in energy markets] could actually increase potential suppliers in capacity markets by reducing barriers to demand resources, which would tend to drive capacity prices down"*, and the need to *"examine the way in which capacity markets already may take into account energy revenues"*.[20]

41. The FERC's conclusions on this topic followed a comprehensive rule making process during which opposing positions on the issue were thoroughly represented (with supporting expert evidence), canvassed and considered.

42. Moreover, the IESO itself has recognized the value DR Resources provide by indicating that it will address the issue of compensation of DR resources for the value that they provide to the IAM.

43. Just and reasonable compensation for DR resources must be addressed, and it must be addressed before the implementation of the TCA so that DR resources are not unfairly driven out of the fledgling capacity market.

D. Instituting a TCA without resolving issues regarding just and reasonable compensation to DR resources is discriminatory.

44. As outlined above, the pre-eminent North American energy regulator – FERC - has carefully and thoroughly considered the role of DR resources in wholesale energy markets, and the issue of just and reasonable compensation of those resources for their participation, and has concluded that:

[20] 134 FERC ¶ 61,187, 18 CFR part 35, Docket No. RM10-17-000; Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets*, March 15, 2011, page 67, footnote 167.

a. Failure to compensate DR resources for the value they provide to energy markets in the same manner as compensation is afforded to generation resources for the value which they supply to energy markets results in wholesale prices that are unjust and unreasonable.

b. The fairness of compensation of wholesale energy market participants for energy services provided influences the fairness and efficiency of capacity markets.

45. It follows that expanding the current DRA platform to allow generation resources eligible for energy market compensation to participate in the broadened capacity auction without addressing just and reasonable compensation for DR resources providing energy market services would result in a capacity market that is unfair and inefficient, and effectively anti-competitive and discriminatory.

46. Without resolution of payment to DR resources for energy services that they can and do provide to the IAM in a manner that fairly recognizes the value of these services provided, inviting generators to compete with DR resources in a capacity auction, which will be the effect of the Amendments, will unduly and unfairly prejudice the ability of those DR resources to compete, and would thus be unjustly discriminatory.

E. Market Rule Amendments which, in the result, are unjustly discriminatory or contrary to the purposes of the *EL Act* must be rejected.

47. The *EL Act* governs the authority of the IESO to make Market Rules, and the manner in which the Board oversees that IESO authority.

48. Subsection 33(9) of the *EL Act* requires the Board to consider whether a Market Rule amendment *"unjustly discriminates against or in favour of a market participant or class of market participants"*. If the OEB so finds, it <u>must</u> make an order revoking the amendment, and referring the amendment back to the IESO for further consideration.

49. For the reasons articulated above, Market Rule amendments which have the effect of allowing generation resources to unjustly and unfairly compete against DR resources for the provision of capacity to the IAM would *"unjustly discriminate against a class of market participants"* – i.e. DR resources currently active in the very successful DRA – and <u>must</u> be revoked by the Board.

50. Furthermore, subsection 33(9) of the *EL Act* requires the Board to consider whether a Market Rule amendment "*is inconsistent with the purposes of this Act*". If the Board so finds, it must make an order revoking the amendment, and referring the amendment back to the IESO for further consideration.

51. For the reasons articulated above, Market Rule amendments which implement the TCA without first addressing the unfairness and anti-competitive impact of requiring DR resources to compete with generation resources, but without the assurance of compensation for energy services provided to the IAM, is inimical to fostering competition. Consequently, it is inimical to many of the objectives of the *EL Act*, including:

a. encouraging electricity conservation and the efficient use of electricity in a manner consistent with the policies of the Government of Ontario;

b. facilitating load management in a manner consistent with the policies of the Government of Ontario;

c. promoting 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;

d. protecting the interests of consumers with respect to prices and reliability of electricity service; and

e. promoting economic efficiency and sustainability in the generation, transmission, distribution and sale of electricity.

Relief Sought

52. For all of the foregoing reasons, AMPCO submits that;

a. the Board should find that the Amendments are;

i. inconsistent with the objectives of the *EL Act*; and/or

ii. unduly discriminatory to DR resources; and

b. having so found, it must to revoke the Amendments and refer them back to the IESO for reconsideration.

53. In addition to the materials filed with this Notice of Appeal and any additional relevant materials from those required to be filed by the IESO in response to this Notice of Appeal,

in support of this application AMPCO proposes to file affidavit material as and when permitted by the Board.

54. AMPCO also requests eligibility to seek recovery from the IESO of AMPCO's reasonably incurred costs of this application.

September 26, 2019

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TAB 2

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

AFFIDAVIT OF COLIN ANDERSON

I, COLIN ANDERSON, of the City of Oakville, in the Province of Ontario, MAKE OATH AND SAY:

1. I am employed as the President of the Association of Major Power Consumers in Ontario (AMPCO). AMPCO is a not-for-profit consumer interest advocacy organization that is active in the electricity sector. AMPCO's members represent Ontario's major industries: forestry, chemical, mining and minerals, steel, petroleum products, cement, automotive and manufacturing, and industrial consumers in general.

2. Since March of 2019, in my role as AMPCO President, I have been closely following and actively participating in the stakeholder process leading up to the market rule amendments at issue on this application. As such, I have knowledge of the matters attested to in this affidavit. I have also had discussions with AMPCO members who directly participate in the Ontario Independent Electricity System Operator (IESO) Administered Market (IAM) as Demand Response resources (DR Resources). Where statements made in my affidavit are based on information from AMPCO members I have so stated.

3. AMPCO has brought this Application on behalf of its members who will be negatively impacted by the amendments at issue. I am providing this evidence, in my role as President of AMPCO, and because of reticence that I perceived among my members to do so themselves. In my view this is an important role for an industry advocacy association, and its President.

4. Accordingly, I provide this affidavit in support of the Application brought by AMPCO for review and revocation of the IESO Ontario Electricity Market Rules (Market Rules) amendments MR-00439-R00-R05 as published by the IESO on September 5, 2019[1] (Amendments). This affidavit also supports the motion brought by AMPCO to stay the operation of the Amendments pending resolution of the Application for review. This affidavit is made for no other or improper purpose.

The Amendments.

5. On September 5, 2019 the IESO published the Amendments on its website.[2]

6. The Amendments facilitate the expansion of the current IESO Demand Response Auction (DRA) to a broader, Transitional Capacity Auction (TCA).

7. The first TCA is scheduled for early December, 2019. Attached at Exhibit A is the IESO's *2020 Transitional Capacity Auction (TCA) Phase 1 Timelines for TCA held in December, 2019*.

8. Although the issue of appropriate compensation for DR Resources for the services they provide to the IAM (i.e., the issue of energy payments to DR Resources) has long been outstanding and has been discussed for some time as part of the IESO's Demand Response Working Group (DRWG), in which I have participated in 2019, the IESO has not yet resolved the issue. It is unlikely that this issue will be resolved before the first TCA happens in December, 2019.

9. AMPCO participated in the stakeholder process leading up to the Amendments, and the six written submissions which AMPCO provided to the IESO between March and July 2019 as part of that process are attached at Exhibit B.

[1] Filed herein as part of AMPCO's Notice of Appeal, Attached as Footnote 1, pages 3 through 60.
[2] The notice of publication is filed herein as part of AMPCO's Notice of Appeal, Attached as Footnote 1, pages 1-3.

AMPCO Members' Participation in the IAM, including the DRA.

10. The IESO's existing Demand Response Auction (DRA) process permits the participation of only DR Resources. The IESO reports that the DRA is a *"valuable and reliable tool for the IESO to secure capacity on the system. Decreasing prices year-over-year demonstrates the ongoing maturity of the demand response market as more consumers participate and competition increases..."*. Attached at Exhibit C is a copy of the IESO's published report on the most recent DRA held in December of 2018.

11. The TCA, proposed to be conducted in early December 2019 under the Amendments, will allow generators to participate in the process, alongside DR Resources.

12. In the existing DRA, the only revenue stream available to participants is a capacity payment. There are currently no payments made for energy activations in the DRA. If the TCA proceeds in December 2019, in a situation where energy is activated, DR Resources will still only qualify for capacity payments, whereas generators will qualify for both capacity payments and energy payments.

13. If the TCA proceeds in accordance with the Amendments, the TCA will allow for two distinct classes of participant – one whose members receive an energy payment (generators) and one whose members do not (DR Resources).

Implications of the proposed TCA.

14. If the TCA is implemented in December 2019, pursuant to the Amendments:

    (a) generators will be able to offer into the auction taking into account their anticipated energy payments, which would allow them to set their "offer price" factoring in the anticipated value of the energy payment stream that they will receive when dispatched;

    (b) DR resources will not have the benefit of such anticipated energy payments, and so will not have an anticipated energy payment stream to factor in when setting their "offer price"; and

    (c) DR resources will thus be at a competitive disadvantage to generators in the auction because they will not have additional anticipated IAM payment streams to factor in when setting their "offer price".

15. I am informed by AMPCO members and verily believe that in the existing DRA process, an IESO proposed “work-around” 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 the generators.

16. Any DR Resource that includes a “utilization payment” amount in its capacity offer (as a proxy for the nonexistent energy payments to DR Resources) will move itself up the offer stack (i.e., make itself more expensive) and no longer be competitive with those entities that do not include such cost elements in their capacity offers.

17. 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.

18. I am informed by some AMPCO members and verily believe, it can be problematic for DR Resources to simply omit “utilization payment” amounts from their capacity offers, since they have no other reasonable means of recovering those amounts in the event that they are activated in the energy market.

19. In other words, if they include utilization amounts, they cannot compete in the capacity market and if they do not include them they may clear the capacity market, but cannot recover legitimate costs if they are activated to provide energy.

20. If the TCA proceeds before appropriate resolution by the IESO of the issue of energy payments for DR Resources, it is unlikely that DR Resources will clear the new capacity market. DR Resources’ inability to be cost competitive will effectively exclude them from participation in a process that was originally exclusive to them (the DRA), and the TCA would thereby replace one set of capacity auction participants (DR Resources) with another (generators).

Harm to DR Resources can be Avoided.

21. By staying the Amendments pending the outcome of AMPCO's broader Application, the effective exclusion of DR Resources from the capacity auction can be avoided. A stay would delay the implementation of the first TCA. That delay would allow the IESO time necessary to appropriately resolve the issue of energy payments to DR Resources – an issue that the IESO has already acknowledged as a barrier to DR Resources' participation in the IAM and that the IESO has long been discussing through the DRWG (see Exhibit D, which is a copy of the IESO *"Active Engagements"* web page discussion of the ongoing IESO work on energy payments for activation of DR Resources). With that issue appropriately resolved, a capacity auction process could be conducted in a manner that is fair for all participants.

22. On the other hand, staying the Amendments pending the outcome of AMPCO's broader Application should have no negative impact to the IAM. Attached as Exhibit E is a copy of a communication from the IESO's CEO, Peter Gregg, stating that, "*it is clear that over the next decade, we have enough energy to meet provincial demand and a limited need for new capacity if existing Ontario resources are reacquired when their contracts expire. We believe these limited capacity needs can be met through existing and available resources such as Demand Response (DR), imports, generators that are coming off long-term contract, uprates and energy efficiency*." The IESO has also indicated that there is no need for additional capacity until the year 2023 when the phase-out of the Pickering nuclear plant begins, as stated in Stakeholder Advisory Committee Meeting Notes dated August 14, 2019, which indicate that the attached Exhibit F.

SWORN BEFORE ME at the City of Toronto, in the Province of Ontario on October 11, 2019

Commissioner for Taking Affidavits
LSUC 55408S

COLIN ANDERSON

EXHIBIT A

THIS IS **EXHIBIT A** REFERRED TO IN THE AFFIDAVIT OF **COLIN ANDERSON** SWORN BEFORE ME, THIS 11th DAY OF OCTOBER, 2019.

Laura Van

A Commissioner, etc.

2020 Transitional Capacity Auction (TCA) Phase 1 Timelines
For TCA held in December 2019

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Process	Activity Milestones	Responsibility	Dates	Comments
Pre Auction Activities				
Pre-Auction Registration	For new Market Participants, the suggested last date to start "Register Organization" to participate in the December 2019 TCA Link to Register an Organization	Organization	30-Jul-19	This applies to non IESO-registered organizations that plan to participate in the TCA. It is a one-time requirement. This step is only applicable to Demand Response organizations (Organizations with capacity auction eligible generation resources are already registered with the IESO).
	For organizations registered with the IESO, the suggested last date to start "Demand Response Auction Participant (DRAP) Authorization" to participate in the December 2019 TCA Link to onlineIESO	Organization	30-Aug-19	Demand Response participants with registered organizations must become Auction Participants (one-time authorization requirement). Registered DRAPs will be migrated from DRAP to Capacity Auction Participant (CAP) by the IESO in early October 2019. This step is only applicable to Demand Response organizations (Organizations with capacity auction eligible generation resources will be eligible to start authorization at a later date mentioned below).
	The suggested date to start the "Capacity Auction Participant (CAP) Authorization" to participate in the December 2019 TCA Link to onlineIESO	Organization	15-Oct-19	Participants not already authorized as DRAP must become Capacity Auction Participants (one-time authorization requirement). This date applies to all organizations with capacity auction eligible generation resource and to organizations with demand response resources that had not authorized as a DRAP. More information is available in Market Manual 12 Section 3.2.
	Last date for all Capacity Auction Participants to complete "CAP Authorization"	Organization	05-Nov-19	Organizations must complete this milestone in order to participate in the TCA to be held in December 2019. Participants not already authorized as DRAP must become Capacity Auction Participants (one-time authorization requirement). This date applies to all organizations with capacity auction eligible generation resources and to organizations with demand response resources that had not authorized as a DRAP.
Reports	Publish TCA Pre-Auction Report Pre-Auction Report	IESO	26-Sep-19	
Capacity Qualification	Suggested start date for the submission of Capacity Qualification information Link to online IESO	Capacity Auction Participant	15-Oct-19	More information is available in the Market Manual 12 Section 3.2. Capacity auction participants are encouraged to initiate the capacity qualification process as soon as feasible. After submitting the capacity qualification information, auction participants are required to provide deposit and the process may require up to 30 days. Participation in the auction is conditional upon providing the auction deposit by the published date.
	Last date to complete the Capacity Qualification (including posting of auction deposit)		27-Nov-19	
Auction Period Activities				
Conduct Transitional Capacity Auction	Start of Capacity Auction Offer Submission Window Link to onlineIESO	Capacity Auction Participant	04-Dec-19 - 09:00 AM	
	End of Capacity Auction Offer Submission Window	Capacity Auction Participant	05-Dec-19 - 05:00 PM	
Reports	Publish TCA Post Auction Report Post Auction Report	IESO	12-Dec-19	
Forward Period Activities Prior to Summer Obligation Period				
Post-Auction Registration	Suggested last date to start "Capacity Market Participant (CMP) Authorization" to participate in the 2020 Summer Obligation Period	Capacity Auction Participant	29-Jan-20	This applies only to auction participants with a capacity obligation that have not previously registered as a DRMP. Registered DRMPs will be migrated from DRMP to Capacity Market Participant (CMP) by the IESO.
	Last date to start "Register/Update Capacity Resources"	Capacity Market Participant	29-Jan-20	Registration of new resources or update existing resources.
	Suggested last date to "Post/Update Capacity Prudential Support"	Capacity Market Participant	02-Mar-20	See Market Manual 5, Part 5.4. Participants that cannot post or update their capacity prudential support by this date are encouraged to speak to the IESO to ensure their prudentials can be processed prior to the obligation period.
	Last date to complete the market registration process to become dispatchable	Capacity Market Participant	17-Mar-20	This requirement is only applicable to the non-dispatchable market participants that are seeking to change attributes of their resources in the IESO's registration system in order to allocate a capacity obligation to a capacity generation resource.
	Last date to be "Authorized as Capacity Market Participant (CMP)"	Capacity Market Participant	30-Mar-20	
	Last date to complete "Register/Update Capacity Resources"	Capacity Market Participant	31-Mar-20	
	Last date to "Register/Update Contributor Management" for Virtual Resources (Monthly Process)	Capacity Market Participant	09-Apr-20	Click to view Calendar for full details
Summer Obligation Period (Summer 2020)				
Energy Market Participation	Summer obligation period begins	Capacity Market Participant	01-May-20	
	Latest date to "Submit Measurement data" for Virtual Resources (Monthly Process)	Capacity Market Participant	23-Jun-20	Click to view Calendar for full details
Forward Period Activities Prior to Winter Obligation Period				
Post-Auction Registration	Suggested last date to start "Capacity Market Participant (CMP) Authorization" to participate in the 2020/21 Winter Obligation Period	Capacity Auction Participant	30-Jul-20	This applies only to auction participants with a capacity obligation that have not previously registered as a DRMP. Registered DRMPs will be migrated from DRMP to Capacity Market Participant (CMP) by the IESO.
	Last date to start "Register/Update Capacity Resources"	Capacity Market Participant	30-Jul-20	
	Suggested last date to "Post/Update Capacity Prudential Support"	Capacity Market Participant	02-Sep-20	See Market Manual 5, Part 5.4. Participants that cannot post or update their capacity prudential support by this date are encouraged to speak to the IESO to ensure their prudentials can be processed prior to the obligation period.
	Last date to complete the market registration process to become dispatchable	Capacity Market Participant	17-Sep-20	This requirement is only applicable to the non-dispatchable market participants that are seeking to change attributes of their resources in the IESO's registration system in order allocate a capacity obligation to a capacity generation resource.
	Last date to be "Authorized as Capacity Market Participant (CMP)"	Capacity Market Participant	29-Sep-20	
	Last date to complete "Register/Update Capacity Resources"	Capacity Market Participant	30-Sep-20	
	Last date to "Register/Update Contributor Management" for Virtual Resources (Monthly Process)	Capacity Market Participant	14-Oct-20	Click to view Calendar for full details
Winter Obligation Period (Winter 2020/21)				
Energy Market Participation	Winter obligation period begins	Capacity Market Participant	01-Nov-20	
	Latest date to "Submit Measurement data" for Virtual Resources (Monthly Process)	Capacity Market Participant	23-Dec-20	Click to view Calendar for full details

EXHIBIT B

THIS IS **EXHIBIT B** REFERRED TO IN THE AFFIDAVIT OF **COLIN ANDERSON** SWORN BEFORE ME, THIS 11th DAY OF OCTOBER, 2019.

Laura Vand

A Commissioner, etc.

March 27, 2019

IESO Stakeholder Engagement
Transitional Capacity Auction (TCA)

Submitted via email

Re: AMPCO Comments on TCA Stakeholdering

AMPCO is the voice of industrial power users in Ontario. Our mission is industrial electricity rates that are competitive, fair and efficient.

Attached are AMPCO's comments on the IESO's stakeholdering of the Transitional Capacity Auction (TCA), as introduced at a public stakeholder session on March 7, 2019. AMPCO appreciates the opportunity to provide such feedback.

Best Regards,

[Original signed by]

Colin Anderson
President

Transitional Capacity Auction

Submissions of the Association of Major Power Consumers in Ontario (AMPCO)

INTRODUCTION

Ontario's electricity system is complex and always evolving. AMPCO provides Ontario industries with effective advocacy on critical electricity policies, timely market analysis and expertise on regulatory matters that affect their bottom line. We are the forum of choice for major power consumers who recognize that their business success depends on an affordable and reliable electricity system.

These submissions are in relation to the IESO's stakeholdering of the Transitional Capacity Auction, as introduced at a public stakeholder session on March 7, 2019. AMPCO's members are major power consumers, responsible for over 15 TWh of annual load in the province. Many of those members participate in the existing Demand Response Auction, which is why AMPCO has an interest in this consultation.

AMPCO appreciates the opportunity to provide feedback and looks forward to continued dialogue.

SUMMARY OF AMPCO COMMENTS

AMPCO appreciates that changes to the Demand Response Auction (DRA) have been contemplated for some time as part of migrating to the Incremental Capacity Auction (ICA). These changes are intended to ultimately reflect the truly competitive nature of the ICA. However, both the pace of those changes as well as some of the specific design elements (or omissions) of the current IESO proposal require some modifications.

Of greatest importance is the clear bias that is being included in the current design whereby generators who receive a demand response activation will receive energy payments, while loads will not. This is clearly discriminatory and cannot be permitted to go forward. This must be remedied now – in Phase One of the project - not at some undetermined future date.

Additionally, the IESO has not included within the current design the ability for all loads to participate in the provision of operating reserve or other ancillary services, such as regulation services. AMPCO believes that again, this represents a bias against loads that should be rectified in a timely fashion.

Accordingly, AMPCO cannot support the TCA in its current form and looks forward to working with the IESO and other stakeholders to correct the proposed design flaws that currently exist.

DISCUSSION

A stakeholder session was hosted by the IESO on March 7, 2019. This was the first public discussion of the newly proposed Transitional Capacity Auction (TCA), which is intended to migrate the existing Demand Response Auction (DRA) into the proposed Incremental Capacity Auction (ICA) which is currently being stakeholdered and designed as part of the overall Market Renewal Program (MRP). As such, the TCA can be regarded as a temporary measure, intended to address capacity shortfalls that occur between now and the initiation of the ICA which is currently scheduled for 2023. Notwithstanding the temporary nature of the TCA, it is expected that many design elements of the TCA will be used as inputs to the ICA – which will be a permanent construct. For this reason, it is imperative that the TCA be appropriately stakeholdered to ensure that its design is as correct, fair and acceptable as possible to all stakeholders.

According to IESO Stakeholder documentation, this engagement will be divided into two phases:

Phase One: Evolving the DRA to enable other resource types to participate. In Phase One of this engagement, the IESO is looking for feedback on auction elements that inhibit or prohibit an eligible resource's ability to participate and provide capacity in the auction and subsequent commitment periods. The IESO will provide a list of proposed design features to be included in the 2019 TCA, as well as define resource eligibility.

Phase Two: Ongoing evolution of the TCA. In Phase Two of this engagement, the IESO will seek feedback on subsequent design improvements to further enable broader participation for future auctions.

In AMPCO's submission, it is unacceptable to tolerate the inclusion of major problems in Phase One by assuming that they will be remedied as part of Phase Two. Phase Two should be viewed as an ongoing initiative to fine-tune the design of the TCA – it should not be relied upon to correct known errors which are intentionally included at the Phase One design stage. Phase One must represent the IESO's and stakeholders' best efforts at a functional and fair design.

With that guiding principle as an objective, AMPCO has a number of comments about the specific materials that were covered at the March 7, 2019 Stakeholder Session:

- In general, AMPCO is concerned at the rapid pace that has been set out for the development of the TCA. AMPCO understands the need for expedience in order to guard against any potential capacity shortfalls, but that expedience should not be achieved at the expense of a correct, fair and well stakeholdered design. We need this quickly, but – more importantly – we need this done right. Accordingly, AMPCO suggests that the IESO review its draft schedule to ensure that appropriate durations exist for meaningful stakeholdering throughout the design and market rule amendment process.
- Slide 7 of the IESO presentation materials includes the Principles that exist in the design of the Market Renewal Program (MRP) and indicate that those principles are also driving the design of the TCA. One of those principles is "Competition", which is further described in IESO documentation as "provide

open, ***fair***, ***non-discriminatory*** competitive opportunities for participants to help meet evolving system needs"[1] [***emphasis*** added]. AMPCO supports this principle and feels that it is particularly relevant, given some of the issues that were discussed on March 7.

- The subject of Energy Payments is a major area of concern for AMPCO. While this subject has been raised before within the Demand Response Working Group, it has not yet been resolved. Arguably, one could take the position that since – currently - the only providers of demand response are loads, the issue is not as important as it will be in the future, since all loads are currently being treated similarly (i.e. equally unfairly). However, as soon as the pool of DR providers is expanded to include generators, a very real discriminatory element is introduced. To be clear – if the current IESO design allows for both generators and loads to secure a capacity payment for provision of DR, but only allows a generator to receive an energy payment in the event that its DR is activated, this is an unacceptable bias that cannot be permitted.
- Ontario is not the only jurisdiction that has contemplated this issue. In the U.S., the Federal Energy Regulatory Commission (FERC) issued its Order 745 in 2011. In the Summary of that Order, the following text appears:

> "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

[1] http://www.ieso.ca/en/Sector-Participants/Market-Renewal/Overview-of-Market-Renewal

market price for energy, referred to as the locational marginal price (LMP)."[2]

- Further, FERC's Order 745 was upheld in January, 2016 by a decision of the Supreme Court of the United States[3].
- The IESO is not the only system operator to engage in consideration of this issue, but it appears to have landed in a different position than many other ISOs. AMPCO recommends that the IESO re-evaluate its decision on this issue and to put a design in place that treats loads consistent with generators – and FERC Order 745 - in their provision of demand response. To not do so is to intentionally create unfairness and discrimination within the TCA design, clearly violating one of the key Market Renewal principles.
- AMPCO also believes that if the DRA would benefit from broader participation, then other markets including operating reserve and regulation would also benefit from increased participation and should be considered for expansion. This does not necessarily have to take place on the same timeline as the TCA, but it should be planned with a clear implementation schedule.

As the TCA design is further revealed, AMPCO reserves the right to comment on other specific features, inclusions or exclusions. AMPCO appreciates the opportunity to provide feedback and looks forward to continued dialogue.

[2] https://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf
[3] https://www.supremecourt.gov/opinions/15pdf/14-840-%20new_o75q.pdf

May 2, 2019

IESO Stakeholder Engagement
Transitional Capacity Auction (TCA)

Submitted via email

Re: AMPCO Comments on TCA Design Document

AMPCO is the voice of industrial power users in Ontario. Our mission is industrial electricity rates that are competitive and fair.

Attached are AMPCO's comments on the IESO's Design Document associated with the Transitional Capacity Auction (TCA). AMPCO appreciates the opportunity to provide such feedback.

Best Regards,

[Original signed by]

Colin Anderson
President

Transitional Capacity Auction – Phase One Design Document

Submissions of the Association of Major Power Consumers in Ontario (AMPCO)

INTRODUCTION

AMPCO provides Ontario industries with effective advocacy on critical electricity policies, timely market analysis and expertise on regulatory matters that affect their bottom line. We are the forum of choice for major power consumers who recognize that their business success depends on an affordable and reliable electricity system.

These submissions are in relation to the IESO's Phase One Design Document (the "Design Document") for the Transitional Capacity Auction (TCA), released for public commentary on April 11, 2019. AMPCO's members are major power consumers, responsible for over 15 TWh of annual load in the province. Many of those members participate in the existing Demand Response Auction, which is why AMPCO has an interest in this consultation.

AMPCO appreciates the opportunity to provide feedback and looks forward to continued dialogue.

SUMMARY OF AMPCO COMMENTS

AMPCO's single most significant area of commentary deals with the unjust discrimination against Demand Response (DR) proponents which exists within the Design Document as a result of a fundamental design flaw. That flaw provides for energy payments for one class of TCA participant (generators) but does not allow for such payments for a second class of TCA participant (DR providers) in similar circumstances.

This discriminatory treatment must be remedied now – during Phase One Design of the project - not at some undetermined future date. Accordingly, AMPCO cannot support the TCA in its current form and looks forward to working with the IESO and other stakeholders to correct this flaw as part of Phase One activities.

DISCUSSION OF THE DISCRIMINATORY DESIGN ELEMENT

1. The Core of the Discriminatory Design Element

   The subject of just and fair treatment and non-discriminatory competition is a major area of concern for AMPCO within the context of the TCA Design Document.

   In general terms, the Design Document sets out, among other things, the process by which participants will offer their available capacity into the TCA. Those offers will be evaluated against the target capacity and each other, and successful capacity providers will be determined based on offer price, with the result being that some participants will be successful in their offers (i.e. they will clear the market, and be eligible to provide capacity during the commitment period) and some will be unsuccessful (they do not clear the market and will not be eligible to provide capacity during the commitment period). Successful participants will receive capacity payments during the commitment period, where unsuccessful participants will not.

   For clarity, entities that offer lower prices will generally be more successful in clearing the TCA than those that offer higher prices. This is intuitively obvious.

   Entities that provide capacity during the commitment period will be obligated to provide corresponding energy offers, for that capacity amount, to allow for the activation of that capacity in the energy market. Should such activations occur, a TCA participant that is a generator will receive energy payments for that portion of its capacity that is activated. A TCA participant that is a DR provider will not. This gets to the core of the discriminatory design element. AMPCO submits that demand response resources must be compensated for the service they provide to the energy market at the market price for energy, in the same way that generators are compensated.

While this subject has been raised before within the context of the Demand Response Working Group, it has not been resolved. Arguably, one could take the position that since currently (i.e. “pre-TCA”), the only providers of demand response are load customers, the issue is not as explicitly unfair as it will be in the future, since all loads are currently being treated similarly (i.e. equally unfairly). There is no discrimination today, since none of the providers receives an energy payment. However, as soon as the pool of DR providers is expanded to include generators, a very real discriminatory element is introduced. Two classes of participants will be created – one that is eligible for energy payments and one that is not. This separation of participant classes is what gives rise to the issue of discriminatory treatment.

If the current IESO design allows for both generators and loads to secure a capacity payment for provision of DR, but only allows a generator to receive an energy payment in the event that its DR is activated, this is unacceptable discrimination that cannot be permitted.

2. Utilization Payments and Energy Payments are Not the Same Thing

In the current Demand Response Auction (DRA) process, it has been possible to avoid having to address this issue by using “Utilization Payments”. Since the only participants in the DRA are on the load side (i.e. no generators currently participate) it has been possible to include amounts in capacity offers that act as a proxy for an energy payment, in a situation where capacity is activated. These amounts are referred to as utilization payments. Since all participants would include these amounts in their capacity offers, the issue of discrimination is avoided.

In the design contemplated within the Design Document, this proxy approach no longer works. Because the TCA will allow for two distinct classes of participant – one who receives an energy payment and one who does not – any participant that includes a utilization payment amount in its capacity offer (as a proxy for the non-existent energy payments) will move itself up the offer stack and no longer be competitive with those entities that do not include such costs elements in their capacity offers. Those participants who include utilization payments in their capacity offers are unlikely to clear the capacity market since they will be including cost elements that other participants (i.e. generators) will not be including, because those other participants will cover those costs in their energy payments that they will receive when activated.

It is also not a viable solution for loads to simply omit utilization payment amounts from their capacity offers, since they have no other means of recovering those costs in the event that they are activated in the energy market. In effect, loads are in a no-win situation. If they include utilization amounts, they cannot compete in the capacity market and if they do not include them they may clear the capacity market, but cannot recover legitimate costs if they are activated to provide energy.

For these reasons, it is clear that the topic of utilization payments does not solve the discriminatory treatment that is inherent within the Design Document. DR providers who only receive capacity payments (either with or without utilization payments) are not competing on a level playing field with generators who receive capacity and energy payments.

3. Other Jurisdictions

Ontario is not the only jurisdiction that has contemplated this issue. In the U.S., the Federal Energy Regulatory Commission (FERC) issued Order 745 in 2011. In the Summary of that Order, the following text appears:

> "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)."[1]

The FERC Order specifically references two conditions that must apply in situations where DR energy payments will take place. First, the resource in question must have the capability to balance supply and demand, and second, the DR resource must be deemed to be "cost-effective". Some form of these conditions could be adopted for use in Ontario to ensure that appropriate resources are paid and that overall value to the system is achieved.

Further, FERC's Order 745 was upheld in January, 2016 by a decision of the Supreme Court of the United States[2]. The following is an excerpt from that ruling:

> "FERC's decision to compensate demand response providers at LMP—the same price paid to generators … is not arbitrary and capricious. … this Court's important but limited role is to ensure that FERC engaged in reasoned decision making—that it weighed competing views, selected a compensation formula with adequate support in the record, and intelligibly explained the reasons for making that decision. Here, FERC provided a detailed explanation of its choice of LMP and responded at

[1] https://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf
[2] https://www.supremecourt.gov/opinions/15pdf/14-840-%20new_o75q.pdf

> length to contrary views. FERC's serious and careful discussion of the issue satisfies the arbitrary and capricious standard."[3]

The IESO is not the only system operator to engage in consideration of this issue, but it appears to be landing in a different position than the Federal Energy Regulator in the U.S. AMPCO strongly recommends that the IESO re-evaluate its decision on this issue and to put a design in place that treats loads consistent with generators in their provision of demand response. To not do so is to intentionally create unfairness and discrimination within the TCA design.

4. The Need to Deal with this Issue in Phase One

According to IESO Stakeholder documentation[4], this engagement is intended to be divided into two phases:

> *Phase One: Evolving the DRA to enable other resource types to participate*. In Phase One of this engagement, the IESO is looking for feedback on auction elements that inhibit or prohibit an eligible resource's ability to participate and provide capacity in the auction and subsequent commitment periods. The IESO will provide a list of proposed design features to be included in the 2019 TCA, as well as define resource eligibility.
>
> *Phase Two: Ongoing evolution of the TCA*. In Phase Two of this engagement, the IESO will seek feedback on subsequent design improvements to further enable broader participation for future auctions.

In AMPCO's submission, it is unacceptable to tolerate the inclusion of major flaws in Phase One by assuming that they will be remedied as part of Phase Two. Phase Two should be viewed as an ongoing initiative to fine-tune the design of the TCA – it should not be relied upon to correct known design errors which are intentionally included at

[3] Ibid
[4] March 25, 2019 IESO Engagement Plan

the Phase One stage. Phase One must represent the IESO's and stakeholders' best efforts at a functional and fair design that is non-discriminatory in nature.

In support of this perspective, Section 1.1 of the Design Document sets out the design principles that will be applied in the creation of the TCA. The second principle listed in that section reads as follows:

- **Competition**: Provide ***open***, ***fair***, ***non-discriminatory competitive opportunities*** for participants to help meet evolving system needs by evolving the DRA to enable additional resources. ***[emphasis added]***[5]

Further to this, Section 1.2 of the Design Document ("Transitional Capacity Auction Objective")[6] states that "The objective of Phase I is to take a first step toward the ICA [Incremental Capacity Auction] by ***increasing competition*** and enabling participation from existing, Noncommitted, Dispatchable Generators … to compete with Demand Response Resources. ***[emphasis added]***"

It can be reasonably concluded by looking at these two sections together that the objective of Phase One of the TCA is to increase competition, but that competition must be open, fair and non-discriminatory.

A Phase One design that does not provide for open, fair and non-discriminatory competitive opportunities has failed to satisfy the stated objective of Phase One of the project. As such, changes must be made to any such design elements prior to the conclusion of Phase One – it is not permissible pursuant to the Phase One stated objective to accept design elements that actively undermine the objective, even if there is an explicit intention to further evaluate the issue in a subsequent stage of the project.

[5] TCA Phase One Design Document, pp 9
[6] TCA Phase One Design Document, pp 10

OTHER SPECIFIC COMMENTS ON THE DESIGN DOCUMENT

The following are other specific comments that AMPCO wishes to advance in respect of the TCA Phase One Design Document.

- Section 2.6 – AMPCO requests additional clarity on the topic of zonal constraints. In particular, the calculation methodology for each of the three zonal limits is of interest.
- Section 6.1.1.1 – AMPCO understands the historical need for the $100/MWh bid price threshold, and does not oppose its continuation as part of the TCA. However, this issue is an example of a control being placed on DR providers, where no such controls are being considered in other situations for generators. AMPCO questions whether Phase One of the TCA should consider some form of Market Power Mitigation in order to drive the appropriate behaviours.
- Section 6.2.3 – AMPCO would like to revisit the values for Non-Performance Factors. As a general statement, AMPCO believes the stated Non-Performance Factors are too high. For loads, the main reason for non-performance would be a forced outage, over which loads have no (or very little) control. Further, during forced outages load are already penalized by the economic consequences of lack of production. Imposing high non-performance factors increases the degree of penalty. AMPCO recommends reducing 1.5 to 1, and 2 to 1.5.

Stakeholder Comment Request – Draft Market Rules and Market Manuals

MR-00439-R00-05 – Transitional Capacity Auction

Date Submitted: *2019/06/04* **Feedback Due:** June 5, 2019	**Feedback provided by:** Company Name: Association of Major Power Consumers in Ontario (AMPCO) Contact Name: Colin Anderson Phone: 416 260-0225 Email: canderson@ampco.org

Please provide comments relating to the section of the draft amendment proposal in the corresponding box. Please include any views on whether the draft language clearly articulates the requirements for either the IESO or market participants. Please provide any alternative language by inserting the draft language below and red-lining the suggested changes.

MR Chapter	Design Element (MR section)	Stakeholder Comments
2	Participation	*Stakeholder comments to be included here.*
2 (app)	Appendices	
3	Administration, Supervision, Enforcement	
7	System Operations and Physical Markets	

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9	Settlements and Billing	
11	Definitions	

MM	Design Element (MM section)	Stakeholder Comments
1.1	Participant Authorization	*Stakeholder comments to be included here.*
1.2	Facility Registration	
1.3	Identity Management	
2.10	Connection Assessment	
4.3	Real-time Scheduling of the Physical Market	
5.4	Prudential Support	
5.5	Physical Market Settlement Statements	
6	Participant Technical Reference Manual	
7.3	Outage Management	
12	Definitions	

Stakeholder comment is requested on the following IESO directed questions that will be forwarded to Technical Panel for their consideration in the recommendation of market rules to the IESO Board of Directors:

Question	Stakeholder Comment
Do you believe there is a clear and common understanding of the intent and purpose of the draft market rule amendment?	
In your view, is this market rule amendment in the interest of consumers with respect to prices?	

In your view, is this market rule amendment in the interest of consumers with respect to the reliability of electricity service?	
In your view, is this market rule amendment in the interest of consumers with respect to the quality of electricity service?	
In your view, are there any adverse effects (not identified in a previous answer) that may be caused by implementing these proposed changes, either to consumers or market participants.	AMPCO believes that the current market rules being developed for the Transitional Capacity Auction (TCA) will result in a serious adverse effect, in the form of discriminatory treatment against a class of market participant, as set out in AMPCO's submission to the IESO dated May 2, 2019.
General Comments: In general, this submission focuses on only one element of the TCA where AMPCO has material comments. AMPCO's silence on any other issue / market rule / market manual should not be interpreted as approval. It should be interpreted as taking no position.	

AMPCO

July 5, 2019

IESO Stakeholder Engagement

Submitted via email

Re: AMPCO Submission – DRWG and TCA (HDR Resources and Energy Payments)

AMPCO is the voice of industrial power users in Ontario. Our goal is industrial electricity rates that are competitive and fair.

Attached is AMPCO's submission made in response to the call for input as part of the Demand Response Working Group's involvement in the proposed Transitional Capacity Auction.

AMPCO appreciates the opportunity to provide such a submission, and looks forward to continuing the dialogue.

Best Regards,

[Original signed by]

Colin Anderson
President

HDR Resources and Energy Payments:

Submissions of the Association of Major Power Consumers in Ontario (AMPCO)

INTRODUCTION

Ontario's electricity system is complex and always evolving. AMPCO provides Ontario industries with effective advocacy on critical electricity policies, timely market analysis and expertise on regulatory matters that affect their bottom line.

These submissions are made in response to the call for feedback issued by the IESO at its June 19 stakeholder session (the Demand Response Working Group (DRWG) meeting). AMPCO's members are major power consumers, responsible for over 15 TWh of annual load in the province. A reliable and affordable energy supply is critical to the success of their businesses, which is why AMPCO has an interest in these discussions.

AMPCO appreciates the opportunity to provide this feedback and looks forward to continued dialogue on the Transitional Capacity Auction (TCA).

SUMMARY

Directionally, AMPCO supports the movement by the IESO on the issue of energy payments for demand response (DR) proponents. However, the pace of the movement does not match the IESO's desired pace for the movement of the reminder of the TCA project.

AMPCO fully supports payments for both out-of-market and economic activations of DR, and AMPCO feels strongly (as set out in its submission of May 2, 2019[1]) that such payments need to be implemented at the same time as the initiation of the TCA

[1] Found at http://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/Meeting-Ontarios-Capacity-Needs-2020-2024

itself. To do otherwise is to embrace a design element that is blatantly discriminatory in nature and counter to clear objectives that have been set for the design of the TCA.

Accordingly, AMPCO suggests that both the out-of-market and economic activations of DR be scheduled to be implemented prior to the first TCA auction. If this necessitates a delay of the first auction, then so be it, since the auction is not required from a reliability perspective in December 2019. It is better to take a little longer and do things correctly than to rush them and include known deficiencies within the design.

In regards to the HDR testing method that the IESO is recommending, AMPCO supports the proposed approach.

MAJOR ELEMENTS OF THE JUNE 19 STAKEHOLDER SESSION

Below are the main elements of the DRWG stakeholder session conducted by the IESO on June 19 on which AMPCO will submit comments:

1. Testing of HDR Resources - Seeking stakeholder feedback on the proposal

2. Cost Recovery for Out-of-Market Activation of DR Resources - Seeking stakeholder feedback on concept and design considerations

3. Energy Payments for Economic Activation of DR Resources - Seek stakeholder input on approach to conducting the analysis.
    - What is the appropriate analysis to complete?
    - Who is best to complete the analysis?
    - Who else should be consulted?
    - When is a decision required by?

AMPCO COMMENTS ON EACH ELEMENT

1. Testing of HDR Resources

AMPCO fully supports the testing approach being proposed by the IESO.

However, as highlighted in AMPCO's submission on the IESO's alternative Load Pricing design, hourly demand response (HDR) still requires some attention from a pricing perspective. In today's market, such resources can participate as NDL while receiving uniform pricing. As part of its new Load Pricing proposal, the IESO has (somewhat arbitrarily) decided that these resources must now be dispatchable and be paid a nodal price, without properly justifying this change. AMPCO does not see the need for this change and as such, cannot support it.

2. Out-of-Market Activation of DR Resources

AMPCO supports the IESO proposal to compensate out-of-market activation of DR resources. AMPCO agrees that these activations (due to testing and emergency situations) can often occur at a price below the bid price of a DR resource. Further, payment for these activations is consistent with energy market and existing design treatment of other resources (including dispatchable loads), thereby leveling the playing field and guarding against any discriminatory treatment that would serve to undermine confidence in Ontario's electricity markets.

In anticipation of compensation being paid for both Out-of-Market as well as Economic Activations, it seems reasonable to maintain consistency between these two different situations. The IESO has listed three potential approaches for consideration in the materials posted on its website on the DRWG page:

- Using energy bids as representative costs
- Historical precedents, such as CBDR activation payments

- Identify costs on individual or type of resource basis

In AMPCO's opinion, the third option would be an administrative nightmare for the IESO and should not be further considered.

The second option has the advantage of having been used previously as part of the Capacity-Based Demand Response (CBDR) Program. However, the value of CBDR, set at that time at $200, seems somewhat arbitrary. While AMPCO could live with this approach, it does not recommend this as the final solution.

The first option has the advantage of being most consistent with what other participants will be receiving. For this reason alone, AMPCO is in favour of option one - using energy bids as representative costs.

3. Economic Activation of DR Resources

In reviewing the points listed on slide 40 of the presentation materials from the June 19 stakeholder meeting[2], AMPCO is struck by the similarities to some of the points raised in its own submission of May 2, 2019. To summarize, when it was only DR that was participating in the DR Auction, all DR resources were impacted equally by proponents' inclusion of expected costs of activations in DR Auction offer prices. However, once another class of participant is introduced, the impact is no longer equal. Accordingly, this same concept needs to be applied to economic activations.

AMPCO strongly supports the compensation of DR resources in economic activations, and believes that it must be consistent with the compensation provided to others and to the compensation contemplated in out-of-market activations.

[2] Found at http://www.ieso.ca/sector-participants/engagement-initiatives/working-groups/demand-response-working-group

While the IESO has agreed to implement compensation for out-of-market activations, it is proposing to undertake additional analysis before reaching a conclusion on economic activations. Given the sentiments expressed on slide 40, AMPCO believes that the conclusion of the IESO analysis is already determined – compensation is appropriate. Any analysis, therefore, should focus on "how" to achieve this end.

The IESO has asked four specific questions as part of its call for submissions. Each will be addressed here.

- What is the appropriate analysis to complete? As already stated (in this and prior submissions), principles of non-discrimination, fair treatment and level playing fields have already dictated that compensation is appropriate. An assessment of whether or not to compensate is therefore not required. The analysis should rather focus on how best to effect compensation and at what level it should be paid. As set out above in the section on out-of-market activations, consistency with other participants should be the paramount criterion.

- Who is best to complete the analysis? AMPCO is mindful of a number of competing considerations in this area. First, there is a need to move swiftly, as will be set out in greater detail below. Second, there is the issue of cost to consider. The benefit of conducting such an analysis should not be overwhelmed by its own expense. Third, one must consider work that has already been done in this area and it should be an objective of the analysis to leverage that work[3] in order to avoid costly duplication of effort. Finally, the credibility of the entity performing the work must be beyond reproach. Conflicts, or perceived conflicts, should be avoided.

[3] Including work in Ontario as well as work that was done pursuant to FERC Order 745, where appropriate.

Consideration of these criteria does not yield one specific entity that should be the clear choice to perform this work. However, the time constraint, in concert with the need to be impartial and to be able to quickly gather and interpret previous relevant analyses points to a body external to the IESO, such as Navigant, who has previously been engaged in work associated with the DRWG.

- Who else should be consulted? AMPCO has few comments in this area. Specifically called out in the IESO materials were the MDAG and the OEB. If the IESO wishes to engage the MDAG, AMPCO has no objections. However, given the role of the OEB in adjudicating conflicts that may arise pursuant to market rule development, AMPCO does not feel that it is appropriate to engage the Board, in any capacity, on this question. The OEB (whether Staff or Board Members) should not be asked to opine on an issue that it could potentially have to decide later. This represents a clear conflict of interest.

- When is a decision required by? This is a critical question. In AMPCO's submission, the issue of compensation for economic activations must be clearly decided – and implemented – prior to the initiation of the TCA. The reasons for this view are clearly articulated in AMPCO's submission of May 2, 2019[4] and (for brevity) will not be repeated here.

  Admittedly, the amount of work that must be done (analysis, rules, manuals, approvals, etc.) is likely too great to be completed by the IESO's desired first auction date of December 2019. If a genuine, urgent reliability concern existed, then this would outweigh the need for executing the first

[4] Found at http://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/Meeting-Ontarios-Capacity-Needs-2020-2024

TCA auction with all of the appropriate design elements in place. This is not the case.

While AMPCO supports the IESO's desire to learn from TCAs in advance of the design and implementation of the Incremental Capacity Auction (ICA), it does not place that desire above the need to implement a fair and non-discriminatory TCA in a situation where no immediate reliability concern is required to be addressed. As AMPCO has stated multiple times in the past – we need to get this right from the start.

Accordingly, AMPCO recommends a six month delay in the start of the TCA in order to accommodate all the work that needs to be done to properly implement the auction.

Alternatively, if for whatever reason the IESO cannot abandon its December 2019 TCA deadline, then the following approach could be adopted. The TCA can proceed on its original timeline, but the promised May 2020 implementation date for out-of-market activations must also apply to implementation of economic activations. In this way DR proponents can be assured that, notwithstanding that the TCA will have commenced, the IESO will have provided its formal assurance that compensation for both types of activations will be designed and implemented by May 2020, at the latest. This means that the auction will be implemented with a known shortcoming, but at least there will be a clear guarantee that the shortcoming will be addressed in a timely fashion.

AMPCO appreciates the opportunity to provide such feedback, and looks forward to continuing to work with the IESO and other stakeholders in designing and implementing a fair, non-discriminatory auction process.

AMPCO

July 9, 2019

IESO Stakeholder Engagement

Submitted via email

Re: AMPCO Submission – MR-00439 – Transitional Capacity Auction

AMPCO is the voice of industrial power users in Ontario. Our goal is industrial electricity rates that are competitive and fair.

Attached is AMPCO's submission made in response to the call for input as part of the market rule amendment process associated with the IESO's proposed Transitional Capacity Auction.

AMPCO appreciates the opportunity to provide such a submission, and looks forward to continuing the dialogue.

Best Regards,

[Original signed by]

Colin Anderson
President

MR-00439 – Transitional Capacity Auction:

Submissions of the Association of Major Power Consumers in Ontario (AMPCO)

INTRODUCTION

Ontario's electricity system is complex and always evolving. AMPCO provides Ontario industries with effective advocacy on critical electricity policies, timely market analysis and expertise on regulatory matters that affect their bottom line.

These submissions are made in response to the call for feedback issued by the IESO in relation to market rule changes required to operationalize the Transitional Capacity Auction (TCA). AMPCO's members are major power consumers, responsible for over 15 TWh of annual load in the province. A reliable and affordable energy supply is critical to the success of their businesses, which is why AMPCO has an interest in these discussions.

AMPCO appreciates the opportunity to provide this feedback and looks forward to continued discussion on the TCA.

GENERAL COMMENT

AMPCO is among the stakeholders that believe the proposal for market rule changes, as it currently stands *"may cause discriminatory treatment against a class of market participants"* [June 25th, TP presentation, page 37]. The proposed market rule changes are designed to facilitate participation by generators in an expanded Demand Response Auction (DRA) platform (i.e. an evolving TCA). Requiring Demand Response (DR) participants to compete against generators in a capacity market without first resolving issues regarding compensation to DR resources for the value which these resources provide in the energy market will undermine the current success of the DRA and handicap DR resources from successfully participating in the market through their own existing (DRA) platform, as AMPCO has previously set out in its submissions to the IESO of March 25, 2019, May 2, 2019, June 5, 2019 and July 5, 2019.

Generators would bid into a TCA taking into account their anticipated energy payments. DR resources would have to compete against these bids without the prospect of an equivalent energy payment stream. DR resources would thus be at a competitive disadvantage to generators in the TCA.

While the IESO proposes to study the introduction of energy payments to DR resources, the study is proposed to be concluded *"before the end of 2020"*, with a next step proposed to be to *"[o]btain input from stakeholders on the approach to conducting the analysis required…"* [IESO Demand Response Working Group Meeting Materials, June 19, 2019, p.7].

While AMPCO does accept resolving the issue of DR resources compensation through DRWG and/or MDAG engagement [June 25th TP Presentation, page 39], we are also of the view that requiring DR resources to compete with generators in a TCA <u>prior to</u> resolution of the issue would:

(a) <u>Undermine</u> competition and market confidence, not only failing to achieve the IESO's objectives for the TCA/ICA program but actually unduly constraining competition.

(b) Introduce undue and unjust discrimination against DR resources in the expanded auction program by requiring them to compete with generators prior to resolution of their eligibility for energy payments.

It is our understanding that, contrary to the suggestion otherwise [June 25th TP presentation, page 39], there are a number of DR participants that remain similarly concerned.

Given the lack of any apparent urgency for launch of the TCA, while supporting the proposed market rule and market manual amendments *per se* AMPCO is of the view that the TCA should <u>not</u> proceed prior to resolution of the issue of appropriate compensation for the value to the market provided by DR resources. Introducing an interim Transitional Capacity Auction (TCA) which undermines the ability of DR resources to compete in Ontario's electricity market would be a regressive step in the quest for enhanced competition and innovation.

July, 2019

IESO PROPOSED CAPACITY AUCTIONS & DEMAND RESPONSE RESOURCES

AEMA/AMPCO BRIEF

Summary of Concerns and Recommendation.

1. The Ontario Independent Electricity System Operator's (IESO) proposal for developing a broadened capacity auction is part of the IESO's overall Market Renewal Program (MRP). The overall objective of the MRP is to encourage and enhance competition[1]:

> *Creating a stable and efficient marketplace that produces value for consumers involves encouraging competition and innovation among suppliers – and is the catalyst behind initiatives to resolve long-standing market design issues.*

2. Proceeding with a broadened capacity auction, in the form of the "Transitional Capacity Auction" (TCA) currently proposed, without first resolving how demand response (DR) resources are compensated for the value that they provide to the IESO administered market (IAM) would not only fail to further this objective, it would undermine this objective.

3. It has been definitively recognized that DR resources can provide electricity wholesale market energy services, and that failure to compensate DR resources for such services in a manner equivalent to compensation provided to generation resources for similar services is unjust and unreasonable.

4. Without ensuring just and reasonable compensation to DR resources, on a comparable basis with other resources which bring similar value to the IAM, the TCA proposal could result in replacement of one set of capacity providing resources with another. This would not enhance competition, but it may well stifle it.

5. While the IESO has indicated that it will address the issue of compensation of DR resources for the value that they provide to the IAM, resolution of this issue is not anticipated prior to the proposed December 2019 implementation of TCA Phase I.

6. Fortunately there appears to be no urgency to proceeding with the TCA. On July 16, 2019 the IESO indicated that it would suspend further work on an "Incremental Capacity Auction" (ICA), the mechanism towards which the TCA was to evolve, in light of an imminent forecast indicating sufficient baseload and other resources to ensure reliability for the foreseeable future. The IESO indicated that work on the TCA would continue as currently planned. The current plan is for an initial TCA by the end of 2019.

7. As there is currently no time frame within which a full ICA program is required, there is no rationale for implementing a TCA prior to resolution of the issue of just and reasonable

[1] IESO Transitional Capacity Auction: Phase I Design Document, April 11, 2019, page 1.

compensation for DR resources in the IAM, and all the more reason for getting the TCA right initially so that it will facilitate, rather than undermine, competition.

8. ***Implementation of the TCA should be deferred. It would be more appropriate and more equitable, and it would better achieve the IESO's stated objectives, to forego the proposed "Phase I" TCA implementation in December, 2019 and instead focus on getting the proposed TCA right from its initiation.***

Background and Current Status.

9. DR is the changing of electricity consumption patterns by end-use consumers in response to market prices.[2]

10. Since 2015 the IESO has held annual demand response auctions (DRAs) to acquire DR capacity from market participants that are able to provide that capacity to the market in exchange for an availability payment[3] (which is for present purposes essentially a "capacity payment" - i.e. a payment to ensure that capacity is available to supply energy services as and when called upon).

11. Four successful DRA's have been held in Ontario, the most recent in December 2018. The IESO's report on the most recent DRA underscores the success of the DRA program[4] [emphasis added]:

> *This year, 38 organizations were registered as auction participants, the highest number since the auction began in 2015. The successful proponents included four new participants who represent a mix of commercial and industrial consumers.*
>
> *The average annual clearing price for availability payments of $52,810/MW represents a 30% decrease from last year, and a 42% decrease since the first auction in 2015. The auction cleared 818 megawatts (MW) for the 2019 summer commitment period and 854 MW for the 2019/2020 winter commitment period.*
>
> *Moving in to its fourth year, the auction has been established as a valuable and reliable tool for the IESO to secure capacity on the system. Decreasing prices year-over-year demonstrates the ongoing maturity of the demand response market as more consumers participate and competition increases. Lower capacity prices benefit all Ontario consumers, while auction participants benefit by offsetting their energy costs and improving their competitiveness.*
>
> *As the electricity system moves towards competitive electricity auctions under IESO's Market Renewal project, the participation of consumers providing demand response will increase competition leading to overall lower prices for Ontario consumers.*

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[2] IESO Market Manual, Part 12.0: Demand response Auction, Issue 6.0, page 4, paragraph 1.
[3] IESO News and Updates page; http://www.ieso.ca/en/Sector-Participants/IESO-News/2018/12/IESO-Announces-Results-of-Demand-Response-Auction
[4] *Ibid*

12. Starting in December, 2019 the IESO is proposing to "transition" the DRA into a broader auction by opening participation to other resources.[5] While the "Phase 1" December, 2019 auction was initially proposed as a first step towards transition to an ICA to be implemented in 2022, with the recently announced suspension of work on the ICA, the first TCA will simply be the first in potentially a series of capacity auction evolutionary steps without any defined end state timing.

13. While AEMA/AMPCO support broadening of the DRA into a more robust and competitive capacity auction mechanism, they are concerned that in the current state of the market for DR such broadening will not only fail to enhance competition for the benefit of Ontario consumers, it will have the opposite effect.

14. Generation resources have other revenue opportunities in the IESO administered markets, including payments for energy services provided. DR resources do not currently have commensurate revenue opportunities for the energy services which they provide to the market.

15. As long as this is the case, commandeering the currently successful DRA into a TCA will not broaden the existing auction platform, it will only result in driving the DR resources that participate in that DRA out of the IESO administered market, and replacing one set of capacity auction participants (DR) with another (generators). This would actually be a step backward in evolution of the IESO administered markets, not a step forward.

16. ***AEMA/AMPCO urge the IESO to match the timing for evolution of capacity auctions with resolution of the issue of how to justly and reasonably compensate DR in the broader IESO administered market.***

17. Given that the IESO now does not anticipate in the foreseeable future a period of significant system need, the current proposal to implement the first TCA in December, 2019 cannot be said to be driven by an imminent need to secure capacity. There is no apparent driver for a rush to implementation of a broadened capacity auction this year.

18. ***AEMA/AMPCO urge the IESO to reschedule the first TCA to allow for sufficient time to ensure just and reasonable and non-discriminatory compensation for DR in the broader IAM, thus preserving the ability of the TCA to enhance, rather than restrict, competition.***

Enhancing competition, for the benefit of consumers.

19. As noted above, the overall objective of the IESO's MRP is to encourage and enhance competition[6]:

> *Creating a stable and efficient marketplace that produces value for consumers involves encouraging competition and innovation among suppliers – and is the catalyst behind initiatives to resolve long-standing market design issues."*

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[5] IESO Transitional Capacity Auction: Phase I Design Document, April 11, 2019, page 2.
[6] IESO Transitional Capacity Auction: Phase I Design Document, April 11, 2019, page 1.

20. The IESO's proposal to evolve the DRA into a broader based capacity auction is to the same end[7]:

> *The ICA will help us to prepare for [a future period of capacity requirement] by allowing more resource types to compete to provide future capacity, enabling the IESO to flexibly meet the province's adequacy needs.*

21. The success of a broadened capacity auction hinges on expanding participation in competition for the provision of capacity:

> *One of the advantages of the ICA is that all eligible sources of capacity – new and existing, on both the supply and demand sides – compete with each other, regardless of resource type. …From the perspective of meeting adequacy needs, there is no functional difference between a megawatt of power from an electricity generating facility and a megawatt of reduced consumption from demand response.* [8]

22. The TCA would start with the DRA, and add non-committed dispatchable generators as eligible capacity auction participants. The IESO's stated intent in so doing is to *"enable competition between additional resource types"*.[9]

23. At the same time the IESO has acknowledged concerns that there are barriers to DR participation in the IESO markets, and that one of these barriers is the unavailability to DR resources of energy payments.[10]

24. The IESO proposes to study the introduction of energy payments for DR resources (i.e. to determine *"whether there is a net benefit to electricity ratepayers if DR resources are compensated with energy payments for economic activations"*. The study proposed is to be concluded *"before the end of 2020"*, with a next step proposed to be to *"[o]btain input from stakeholders on the approach to conducting the analysis required to make this determination"*.[11]

25. Requiring DR resources to compete against generators without resolving the comparative value of DR resources and generation resources in the energy market, and how to justly and reasonably compensate the former in a manner comparable to the latter, would undermine the current success of the DRA and handicap DR resources from successfully competing within their own existing market platform.

    (a) Generators will bid into capacity auctions taking into account their anticipated energy payments.

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[7] IESO *Incremental Capacity Auction High-Level Design: Executive Summary*, March 2019, page 1.
[8] IESO *Incremental Capacity Auction High-Level Design: Executive Summary*, March 2019, page 3.
[9] *Transitional Capacity Auction Phase I Design Document*, April 11, 2019, p.2.
[10] IESO Demand Response Working Group Meeting Materials, June 19, 2019, pages 54 *et seq.*
[11] IESO Demand Response Working Group Meeting Materials, June 19, 2019, page 7.

(b) DR resources will have to compete against these bids without an <u>equivalent</u> energy payment stream, putting DR resources at a competitive disadvantage to generators in the capacity market.[12]

26. Requiring DR resources to compete with generators in a TCA prior to resolution of the eligibility of DR resources for energy payments would:

(a) <u>Undermine</u> competition and market confidence, a result inimical to the IESO's objectives for the capacity auction program and its MRP in general.

(b) Introduce undue discrimination against DR resources in the expanded auction program by requiring them to compete with generators prior to resolution of their eligibility for energy payments.

(The IESO has recently recognized just this sort of issue in respect of DR compensation for out of market Hourly DR resource activations.[13])

27. Premature introduction of a TCA such that it undermines the ability of DR resources to compete in Ontario's competitive electricity market would be a <u>regressive</u> step in the quest for enhanced competition and innovation.

28. Commandeering the current DRA to a broader auction platform without first addressing the competitive position of DR resources *vis a vis* generators and other sources of capacity would unnecessarily damage a highly successful existing market mechanism, which would be unfair to DR resources, counterproductive to robust evolution of the Ontario electricity market, and irresponsible on the part of the IESO.

Failing to recognize and compensate the value of DR resources to the energy market is unjust and unreasonable.

29. It has been definitively recognized that DR resources can provide electricity wholesale market energy services, and that failure to compensate DR resources for such services is unjust and unreasonable.

30. In a Final Rule issued in March, 2011 the United States Federal Energy Regulatory Commission (FERC) determined that:[14]

> *… when a demand response resource participating in an organized wholesale energy market… 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… that demand response resource must be compensated for the service it provides to the energy market at the market price for energy…*

[12] Energy payments avoided by the load are <u>not</u> economically equivalent to energy payments for provision of demand reduction to the market, and are not adequately compensatory for the value provided by DR resources to the energy market: 134 FERC ¶ 61,187, 18 CFR part 35, Docket No. RM10-17-000; Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets*, March 15, 2011, paragraph 62.

[13] IESO Demand Response Working Group Meeting Materials, June 19, 2019, pages 36 *et seq*.

[14] 134 FERC ¶ 61,187, 18 CFR part 35, Docket No. RM10-17-000; Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets*, March 15, 2011, page 1.

> *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.*

31. The FERC's conclusions on this topic followed a comprehensive rule making process during which opposing positions on the issue were thoroughly represented (with supporting expert evidence), canvassed and considered.

32. On January 25, 2016, the Supreme Court of the United States issued a determination that in making the foregoing determination FERC was within its jurisdiction to regulate wholesale power markets. While expressly eschewing making a finding on the correctness of FERC's determination as outside of the Court's legitimate area of inquiry, following a detailed 33 page review of the evidence and arguments placed before FERC in the rule making process, the Court commented:[15]

> *Our important but limited role is to ensure that the Commission engaged in reasoned decision making – that it weighed competing views, selected a compensation formula with adequate support in the record, and intelligibly explained the reasons for making that choice. FERC satisfied that standard.*

33. FERC's determination that establishing just and reasonable wholesale power market rates requires that a DR resource must be compensated for the service it provides to the energy market at the market price for energy was subject to satisfaction of a "net benefits test" to assess the appropriateness of that DR compensation. The "net benefits test" condition was applied to address what was referred to in the FERC's rule making proceeding as the "billing unit effect" of dispatching DR resources in the energy market. Essentially, the concern is that as the volume of energy consumed declines when DR resources actually reduce demand (i.e. avoid consuming energy), the reduction in the costs to meet overall energy demand by dispatching competitive DR is offset in end-user rates to some extent by the fewer units consumed, resulting in an upward pressure in the price for each unit. Whether the reduced costs of supply outweigh the upward pressure on unit rates determines whether there is a "net benefit" for end-users from participation of the DR resource in the market. If there is, then it is in the interest of consumers that DR resources be dispatched when they require a lower energy payment than other resources bidding into the market.

34. On this point FERC concluded as follows[16]:

> *For this reason, the billing unit effect associated with dispatch of a demand response resource in an energy market must be taken into account in the economic comparison of the energy bids of generation resources and demand response resources. Therefore, rather than requiring compensation at [marginal price] in all hours, the Commission requires the use of the net benefits test described herein to ensure that the overall benefit of reduced [marginal price] that results from dispatching demand response resources exceeds the cost of*

[15] Federal Energy Regulatory Commission v. Electric Power Supply Association Et Al., 577 U.S. (2016), page 33.

[16] 134 FERC ¶ 61,187, 18 CFR part 35, Docket No. RM10-17-000; Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets*, March 15, 2011, paragraph 53.

> *dispatching those resources. When the above-noted conditions of capability and of cost effectiveness are met, it follows that demand response resources that clear in the day-ahead and real-time energy markets should receive the [marginal price] for services provided, as do generation resources.*

35. In the course of its consideration of the equivalency of DR resources and generation resources in providing energy services, the importance of recognizing and compensating this equivalency appropriately, and the importance of thus reducing barriers to DR participation in wholesale markets, FERC cited an earlier order which included a finding that[17]:

> *A market functions effectively only when both supply and demand can meaningfully participate, and barriers to demand response limit the meaningful participation of demand in electricity markets.*

36. FERC went on to find that:

> *Removing barriers to demand response will lead to increased levels of investment in and thereby participation of demand response resources (and help limit potential generator market power), moving prices closer to the levels that would result if all demand could respond to the marginal cost of energy.*[18]
>
> *…*
>
> *In Order No. 719, the Commission found that allowing demand response to bid into organized wholesale energy markets "expands the amount of resources available to the market, increases competition, helps reduce prices to consumers and enhances reliability."*[19]

37. In its rulemaking deliberations FERC also considered arguments that DR resources are "compensated" by avoiding energy costs when responding to requests to curtail consumption, and accordingly paying such resources for energy thereby effectively supplied would amount to double compensation. On these arguments FERC found as follows:[20] [emphasis in original]

> *Furthermore, Dr. [Alfred E.] Kahn argues that paying demand response [marginal price] sets "up an arrangement that treats proffered reductions in demand on a competitive par with positive supplies; but one is no more a [case of overcompensation]*[21] *than the other: the one delivers electric power to users at marginal costs – the other – <u>reductions in cost</u> – both at competitively-determined levels.*
>
> *… 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,*

[17] Ibid, paragraph 57, citing FERC Order No. 719.
[18] Ibid, paragraph 59.
[19] Ibid, paragraph 61.
[20] Ibid, paragraph 62.
[21] Insert in original.

> *as requested by some commenters, single out demand response resources for adjustments to compensation. The Commission has long held that payment of [marginal price] to supply resources clearing the day-ahead and real-time energy markets encourages "more efficient supply and demand decisions in both the short run and long run," 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.*

38. FERC also recognized in its rule making findings the interrelationship between just and reasonable compensation to DR resources in energy markets and the fairness of associated capacity markets. FERC noted *"how the increased participation by demand resources [in energy markets] could actually increase potential suppliers in capacity markets by reducing barriers to demand resources, which would tend to drive capacity prices down"*, and the need to *"examine the way in which capacity markets already may take into account energy revenues"*.[22]

Instituting a TCA without resolving issues regarding just and reasonable compensation to DR resources is discriminatory.

39. As outlined above, the pre-eminent North American energy regulator – FERC – has carefully and thoroughly considered the role of DR resources in wholesale energy markets, and the issue of just and reasonable compensation of those resources for their participation, and has concluded that:

    (a) Failure to compensate DR resources for the value they provide to energy markets in the same manner as compensation is afforded to generation resources for the value which they supply to energy markets results in wholesale prices that are unjust and unreasonable.

    (b) Fair compensation of wholesale energy market participants for energy services provided influences the fairness and efficiency of capacity markets.

40. It follows that expanding the current DRA platform to allow generation resources eligible for energy market compensation to participate in the broadened capacity auction without addressing just and reasonable compensation for DR resources providing energy market services would result in capacity markets that are effectively anti-competitive and discriminatory.

41. Without resolution of payment to DR resources for energy services that they can and do provide to the energy market in a manner that fairly recognizes the value of these services provided, inviting generators to compete with DR resources in a capacity auction would unduly and unfairly prejudice the ability of those DR resources to compete, and would thus be discriminatory.

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[22] 134 FERC ¶ 61,187, 18 CFR part 35, Docket No. RM10-17-000; Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets*, March 15, 2011, page 67, footnote 167.

Market Rule Amendments which, in the result, are discriminatory, must be rejected.

42. The Ontario *Electricity Act, 1998* (*EL Act*) governs the authority of the IESO to make Market Rules, and the manner in which the Ontario Energy Board (OEB) oversees that IESO authority.

43. Subsection 33(9) of the *EL Act* requires the OEB to consider whether a Market Rule amendment *"unjustly discriminates against or in favour of a market participant or class of market participants"*. If the OEB so finds, it must make an order revoking the amendment, and referring the amendment back to the IESO for further consideration.

44. For the reasons articulated above, Market Rule amendments which have the effect of allowing generation resources to unjustly and unfairly compete against DR resources for the provision of capacity to the IAM would *"unjustly discriminate against a class of market participants"* – i.e. DR resources currently active in the very successful DRA – and would have to be revoked by the OEB.

45. The IESO should refrain from instituting Market Rule amendments which would co-opt the current DRA platform to a broadened capacity auction prior to addressing the currently unjust and unreasonable wholesale energy market compensation structure under which DR resources are not fairly and properly compensated for the energy services which they provide to the IAM.

46. To proceed with the TCA related Market Rule amendments proposed without first addressing this unfairness would have the effect of unjustly discriminating against DR resources competing to provide capacity to the IAM. Such amendments would not withstand regulatory review.

Recommendation.

47. The unjust discrimination outlined above would be particularly objectionable where there is no need to rush to ICA implementation prior to resolution of the issue of just and reasonable compensation for DR resources in the wholesale energy market. With the suspension of work on the ICA as a result of an updated forecast which sees no resource constraints for the foreseeable future there is no justification for rushing to TCA implementation.

48. AEMA and AMPCO support expansion of the current DRA into a broader capacity auction platform, and the use of a broadened capacity auction platform along with other competitive procurement options to address future capacity needs.

49. While AEMA/AMPCO recognize that the IESO has now proposed a study, to be completed by the end of 2020, to determine *"whether there is a net benefit to electricity ratepayers if DR resources are compensated with energy payments for economic activations"*, as outlined above the FERC has already exhaustively considered this issue as recognized by the U.S. Supreme Court, and has unequivocally concluded "yes". Repeating this comprehensive examination is unnecessary and wasteful. That work has already been done, and concluded.

50. A more appropriate, and considerably more focussed, inquiry to validate the "net benefits" to consumers should not take until the end of 2020.

51. In order to enhance competition and market confidence, both to the ultimate benefit of Ontario's electricity consumers, **AEMA and AMPCO urge the IESO to:**

(a) **Recognize and respect both its own overall MRP objectives and its capacity auction specific objectives of *"[c]reating a stable and efficient marketplace that produces value for consumers"* by *"encouraging competition and innovation among suppliers"* and *"resolv[ing] long-standing market design issues"*[23].**

(b) **Proceed expeditiously with a more focussed study to validate the "net benefits" to consumers of energy payments for DR resources, so that the study can be concluded as soon as feasible and its results implemented.**

(c) **Defer implementation of a TCA from December, 2019 and instead focus on getting the proposed TCA right from its initiation, following resolution of the issue of compensation of DR resources for the value that they provide to the IAM.**

(d) **Thereby avoid a result which would unfairly and unjustly discriminate against DR resources in the IAM.**

TOR_LAW\ 9986048\7

[23] IESO Transitional Capacity Auction: Phase I Design Document, April 11, 2019, page 1.

EXHIBIT C

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Laura Vrom

A Commissioner, etc.

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News and Updates

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IESO Announces Results of Demand Response Auction

December 13, 2018

The results of the Independent Electricity System Operator's (IESO) fourth demand response (DR) auction shows continued growth in consumer participation and significant decreases in cost.

The auction is an annual competitive process through which participating residential, commercial and industrial consumers are selected to be available to reduce their electricity consumption as needed. Successful DR providers compete in the electricity market along with generators to help maintain the reliability of the province's electricity system.

This year, 38 organizations were registered as auction participants, the highest number since the auction began in 2015. The successful proponents included four new participants who represent a mix of commercial and industrial consumers.

The average annual clearing price for availability payments of $52,810/MW represents a 30% decrease from last year, and a 42% decrease since the first auction in 2015. The auction cleared 818 megawatts (MW) for the 2019 summer commitment period and 854 MW for the 2019/2020 winter commitment period.

Moving in to its fourth year, the auction has been established as a valuable and reliable tool for the IESO to secure capacity on the system. Decreasing prices year-over-year demonstrates the ongoing maturity of the demand response market as more consumers participate and competition increases. Lower capacity prices benefit all Ontario consumers, while auction participants benefit by offsetting their energy costs and improving their competitiveness.

As the electricity system moves towards competitive electricity auctions under IESO's Market Renewal project, the participation of consumers providing demand response will increase competition leading to overall lower prices for Ontario consumers.

The full list of this year's successful participants is as follows:

Participant	Summer Capacity Cleared [MW]	Winter Capacity Cleared [MW]
CPOWER ENERGY MANAGEMENT CORPORATION	11.6	14.1
DIRECT ENERGY MARKETING LIMITED	11	14
ENERNOC LTD.	216.3	203.4
GC PROJECT LP	20.1	19.1
GERDAU AMERISTEEL CORPORATION	72	72
GERDAU AMERISTEEL CORPORATION -CAMBRIDGE	2.4	2.4
IVACO ROLLING MILLS 2004 L.P.	25	25

Participant	Summer Capacity Cleared [MW]	Winter Capacity Cleared [MW]
NRG CURTAILMENT SOLUTIONS CANADA, INC.	143.5	143.5
NRSTOR C&I L.P.	2.4	21.8
PEAK POWER INC.		1
RESOLUTE FP CANADA INC.	28	28
RODAN ENERGY SOLUTIONS INC	201.7	203.1
TEMBEC ENTERPRISES INC.	40	40
VOLTUS ENERGY CANADA LTD	44.4	66.8
Total	**818.4**	**854.2**

Additional information about the auction is available on ~~Demand Response Auction~~ webpage.

More information regarding technical difficulties experienced this year and a quick refresher on the treatment of zonal limits in the auction mechanism can be found here.

The next DR auction will be held in December 2019, for delivery of DR capacity for summer 2020 and winter 2020/2021. Through the Demand Response Working Group, the IESO will continue to evolve demand response as it shifts to more competitive ways to secure capacity.

More information about Market Renewal can be found at ~~Electricity Market of Tomorrow~~ webpage.

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EXHIBIT D

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Laura Vaul

A Commissioner, etc.

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Menu

Sector Participants > Engagement Initiatives > Energy Payments for Economic Activation of DR Resources

Active Engagements

The IESO is committed to an open, two-way dialogue with stakeholders and communities to help understand their views about proposed changes that may affect them.

IN THIS SECTION...

Status of Active Engagements

2019 Conservation Achievable Potential Study

Development of an IESO Competitive Transmission Procurement Process

Energy Storage Advisory Group

Formalizing the Integrated Bulk System Planning Process

Improving Accessibility of Operating Reserve

Innovation and Sector Evolution White Paper Series

Capacity Auction

Energy Payments for Economic Activation of DR Resources

Integrated Regional Resource Plan - Kitchener-Waterloo-Cambridge-Guelph

Regional Electricity Planning – East Lake Superior

Regional Planning – Greater Bruce/Huron

Integrated Regional Resource Plan - Ottawa Area Sub-Region

Integrated Regional Resource Plan - Windsor-Essex

Integrated Regional Resource Plan - York Region

Market Development Advisory Group

Meeting Ontario's Capacity Needs: 2020-2024

Planning Outlook

Regional Planning Review Process

Regional Planning - GTA West

Renewable Distributed Generation Integration (RDGI) Fund

Transmission Asset End-of-Life: Asset Replacement Information Process

Completed Engagements

Energy Payments for Economic Activation of Demand Response Resources

Energy payments (or utilization payments) for the economic dispatch of demand response (DR) resources has been an ongoing topic of discussion at the Demand Response Working Group (DRWG). Stakeholder interest in energy payments was renewed as a result of proposed market rule amendments to enable off-contract, non-regulated dispatchable generators to participate in the capacity auction along with dispatchable loads and hourly demand response resources.

To date, DRWG has been the forum for discussions with stakeholders on energy payments for DR resources – for both economic dispatch and out-of-market activations. However, given that energy payments for economic dispatch of DR resources is a complex issue and would be a substantive change to Ontario's energy market, the IESO has determined that a broader stakeholder engagement is needed to advise on this issue. Energy payments for out of market activations will continue to be discussed through DRWG with the intent to implement the proposal by the December 2019 capacity auction.

Through this engagement, the IESO will seek feedback from stakeholders on:

- The inputs and outputs of the research and analysis required to determine whether there is a net benefit to electricity ratepayers if DR resources are compensated with energy payments for economic activations. The IESO will commission a third party consultant to support the research and analysis.

- The IESO's decision and rationale on whether demand response resources will be compensated with energy payments for economic activations

Additional details on the IESO's plans to engage with stakeholders can be found in the engagement plan. All comments and enquiries on this engagement can be directed to engagement@ieso.ca.

Anticipated timing for this engagement is presented below.

Schedule of Activities

Date	**Activities**
June 2020	Post IESO final decision and rationale
May 2020	Present draft IESO decision and rationale for stakeholder review
Q1 2020	Post final research findings and analysis
Q1 2020	Present draft research findings and/or analysis for stakeholder review
November 2019	Present final study scope and study plan
October 10, 2019	Meeting to review engagement plan and objectives, draft scope of research and analysis for stakeholder feedback
September 11, 2019	Stakeholder Feedback • AEMA

Date	Activities
August 22, 2019	Engagement launched – stakeholders to provide feedback on ~~engagement plan~~ by September 11, 2019 to ~~engagement@ieso.ca~~ • Communication

EXHIBIT E

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Laura Van

A Commissioner, etc.

From: IESO Engagement
Sent: July 16, 2019 11:45 AM
To: IESO Engagement
Subject: Market Renewal Update

I want to provide you with a status report on our market renewal efforts and outline some of the changes that we are making with respect to the plans for the Incremental Capacity Auction (ICA). This revised approach reflects an update in our planning assumptions and allows us an opportunity to respond to the stakeholder comments that we have received about the ICA.

The Independent Electricity System Operator (IESO) will be releasing our annual planning outlook over the next few months. As we finalize the report, it is clear that over the next decade, we have enough energy to meet provincial demand and a limited need for new capacity if existing Ontario resources are reacquired when their contracts expire. We believe these limited capacity needs can be met through existing and available resources such as Demand Response (DR), imports, generators that are coming off long-term contract, uprates and energy efficiency. We do not see a need for new baseload resources to meet those limited capacity needs over the next 10 years.

As a result, we are stopping further work on the current High Level Design (HLD) for the ICA. We will instead continue with our efforts to implement the Transitional Capacity Auction with a first auction this December. We will evolve this auction over the next few years while also further engaging with stakeholders to determine how their ICA feedback should be reflected in our plans going forward and which features from the original HLD are needed to support an enduring capacity auction mechanism in Ontario.

We will continue to enable the initiatives contained within the energy stream of Market Renewal, including the pricing changes associated with the single schedule market. Responding to concerns from large customers, we have put forward an alternate design on load pricing that meets the key objectives of both the IESO and the Association of Major Power Consumers of Ontario. We will be seeking approval from our Board of Directors on the energy stream HLD later this summer, and we will be proceeding with an energy-only business case at this time.

We have also initiated work at the DR Working Group to address concerns about demand side participation in our capacity auctions.

With the existing conservation framework set to end at the end of 2020, we will also explore whether energy efficiency results can be more competitively acquired, including through the use of a capacity auction.

Additional details on today's announcement will be available at the next Market Renewal stakeholder meeting tomorrow.

We remain committed to a more competitive electricity marketplace and working with all of our stakeholders in developing the capacity auction process that can meet our resource adequacy needs. This work will help ensure that future electricity needs can be reliably met at the least cost to Ontario electricity customers.

Peter Gregg

+++This message is being sent to all participants in the Market Renewal Program stakeholder engagements.

EXHIBIT F

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Laura Vann

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A Commissioner, etc.

IESO Stakeholder Advisory Committee Meeting Notes – August 14, 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)
Mr. Pat Chilton (representing Ontario Communities)
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 Dist ributors)
Mr. Paul Norris (representing Generators)
Mr. Mark Passi (representing Consumers, via teleconference)
Mr. Mark Schembri (representing Consumers)
Mr. James Scongack, Vice Chair (representing Generators)
Mr. Terry Young (representing IESO)
Regrets:
Mr. Frank Kallonen (representing Distributors and Transmitters)
Mr. Hari Suthan (representing Energy Related Businesses and Services)

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

Presentations:
Mr. Peter Gregg
Mr. Terry Young

August 20, 2019
Please report any comments by email to engagement@ieso.ca

Ms. Barbara Ellard
Mr. Chuck Farmer
Mr. Leonard Kula
Ms. Candice Trickey
Ms. Barbara Anderson

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

Agenda Item 1. Welcome Remarks

Mr. Brian Bentz welcomed Mr. Pat Chilton to the SAC. Mr. Chilton hails from Moose Factory and currently lives in Timmins. He is the CEO of Five Nations Energy Inc.

Mr. Bentz welcomed a special guest to the meeting: the Hon. Bill Walker is the new Associate Minister of Energy and represents the riding of Bruce–Grey–Owen Sound. Elected to the legislature in 2011, he was formerly the Minister of Government and Consumer Services. Mr. Scongack noted that Bruce Power has worked extensively with Mr. Walker, and said he is known as a politician dedicated to community engagement.

Mr. Walker said the Minister of Energy, Premier, cabinet, and caucus members are all committed to ensuring reliability and cost effectiveness within the energy sector and that stakeholder engagement will play an important role.

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

Mr. Young provided the following business updates:

On the conservation front, the IESO is delivering the Interim Energy-Efficiency Framework that was introduced at the end of March. Participation levels are comparable to the previous framework. The IESO has worked closely with local distribution companies (LDCs) with respect to the submission of wind-down costs, transfer of customer applications, and coordinated communications. Customer disruption has been minimal.

The Achievable Potential Study was recently completed and the final report will be available in September. It identifies energy efficiency potential in Ontario.

The IESO is developing an energy-efficiency auction pilot to test the feasibility of acquiring peak demand reductions through an auction mechanism. The objective is to inform the future opportunities for energy efficiency to compete directly against other resources in a capacity auction or through an alternative competitive procurement mechanism. A draft will be released in the fall for feedback. The intent is to hold a single auction next year with a two-year commitment period.

As part of the Interim Energy-Efficiency Framework, the Local Program Fund makes funding available to LDCs to deliver local programs that are not duplicative of the IESO province-wide programs. Applications are now being accepted. Four local program concepts have been approved. Three concepts follow a collaborative delivery model that involves the participation of 19 LDCs. Half of the $27-million budget has been committed.

With respect to stakeholder and community engagement, planning activities are continuing in eight regions. The third First Nations Energy Symposium will take place in Toronto on November 4-5 with the theme of local capacity building. An energy workshop is being planned for the Métis Nation of Ontario in order to understand its priorities and interests. The IESO has taken over delivery of conservation programs for First Nation communities.

A Technical Panel (TP) meeting was held yesterday during which members reviewed the market rules to enable the first capacity auction in December 2019. The TP voted to recommend IESO board approval, and approval will be sought this month.

Mr. Jim Hogan commended the IESO for expanding the scope of the Windsor-Essex regional plan to include significant growth happening in the agricultural sector west of London.

Ms. Brandy Giannetta noted that expanded representation is needed on the TP, particularly from distributed energy resources (DERs). Mr. Young said the composition of the TP is under consideration.

Mr. Mark Schembri asked if retail consumers would be eligible to participate in the energy-efficiency auction pilot. Mr. Young said the IESO is working this out, but he sees no reason why they would not be allowed in.

Ms. Rachel Ingram said with respect to the market rule amendments that were approved yesterday by the TP for the Transitional Capacity Auction (TCA), there is concern that the Association of Major Power Consumers in Ontario (AMPCO) and the Advanced Energy Management Alliance (AEMA) brief was posted just 18 hours prior to the TP meeting and that this did not provide sufficient time for consideration of objections to the amendments. It is hoped that the objections will be made available to the IESO board. Mr. Young said the IESO's understanding was that AMPCO and AEMA requested a meeting to discuss this submission in advance of its posting and that it was posted immediately following the meeting with the IESO. Mr. Young stated that the legal brief would be made available to the board.

Ms. Julie Girvan asked if the energy-efficiency auction pilot is being developed internally by the IESO. Mr. Young replied that it is. Proposals will be sought later this year and the auction will take place in 2020.

Mr. Bruno Jesus asked if loss reduction is being considered in the energy-efficiency auction pilot. Mr. Young said the scope has not been finalized.

Mr. Nicolas Bossé noted that it is interesting that those at the retail level would be allowed to participate in a wholesale product offering within the capacity auction.

Comment from the Floor

Mr. Colin Anderson, AMPCO, echoed Ms. Ingram's concern that the TP did not have sufficient time to read and understand objections made to the market rule amendments for the TCA, or to address what was seen as a fundamental flaw in the market rules. Mr. Young noted that the chair of the TP offered to defer the vote at yesterday's meeting, but the committee decided to go ahead.

Mr. James Scongack commented that the IESO does a lot of stakeholder engagement work and takes stakeholder feedback as an input but that ultimately the IESO needs to make a decision that it is accountable for. Mr. Scongack suggested that a future SAC meeting held in Northern Ontario would serve to broaden stakeholder participation.

Agenda Item 3. Update from the CEO
Mr. Peter Gregg

Mr. Gregg introduced two new IESO board members in attendance.
Ms. Patricia Koval is a corporate director and lawyer, a former adjunct professor at the University of Toronto, and a recently retired senior partner from Torys LLP. She serves on the board of Trans Mountain Corporation. She is a member of the board of the Institute of Corporate Directors and the Canadian Performance Reporting board of the Chartered Professional Accountants of Canada. She is chair of the Toronto Region Conservation Foundation and serves on various conservation-focused organizations, including the Ontario regional board of the Nature Conservancy of Canada.

Mr. Michael Bernstein is president of Juno Advisors Ltd., a private investment company. He is the former president and CEO of Capstone Infrastructure Corporation and the former chair of the Association of Power Producers of Ontario.

Mr. Steve Baker, former president of Union Gas Limited, and Mr. Richard Wilson, a partner in PwC Canada's cyber security and privacy practice, have also joined the IESO board.

Mr. Gregg noted that it was 16 years ago today that Ontario last experienced a major power blackout. Much progress has been made since then toward enhancing reliability, including improved compliance to the standards governed by the North American Electric Reliability Corp (NERC).

Mr. Gregg explained the rationale for the IESO decision to stop work on the Incremental Capacity Auction (ICA). Firstly, there is sufficient energy available in the province for the next two decades. Foreseeable additional capacity needs of 1000-2000 MW over this period can be met with existing and available resources, eliminating the requirement for new base load. Secondly, there were stakeholder concerns surrounding the High Level Design of the ICA and these concerns need to be better understood. The IESO remains committed to using competition to balance reliability and cost effectiveness. The first expanded Demand Response (DR) auction will take place in December 2019 and new resources will be added during the next few years. Recognizing that the capacity auction does not necessarily work for all resources, alternative procurement processes will be considered.

The next annual planning outlook will be released this fall and extensive stakeholder engagement will begin on how best to meet the needs in the outlook. While a capacity auction is one method we would like to hear from stakeholders what other procurement mechanisms should be considered. A cost-benefit analysis to support decisions will be important. Thanks in part to the hard work of stakeholders, the energy stream is moving along well.

The IESO revenue requirement has been flat for the past three years. The IESO has proposed an increase of around 2% per year and this will be presented to the board in a few weeks' time. The increase is needed to support wage growth in collective agreements and to manage cyber security enhancements in next few years. The new five-year strategic plan reinforces the IESO commitment to a competitive marketplace. The plan will be submitted to the minister in early September.

Comments

Mr. Bentz said it is becoming more difficult to forecast load. How does the IESO manage volatility of load going forward? Mr. Gregg said various scenarios are reflected in the annual planning outlook. The IESO has developed a sensitivity analysis and is confident that the right amount of conservatism is built in. The capacity market will put resources through a relatively small time commitment compared with 20-year contracts. Continued development of the capacity market is essential to managing volatility.

Ms. Dezell echoed Mr. Bentz's point about increasing volatility and suggested that the IESO keep a long-term perspective. Mr. Gregg replied that moving away from the ICA does not mean moving away from a long-term view.

Mr. Scongack said the ICA was causing a lot of distraction, for better or for worse, and stopping work on it will allow the sector to focus.

Mr. David Butters agreed that shelving the ICA was a good decision. He questioned the use of the term Transitional Capacity Auction. Mr. Gregg said the IESO is shifting away from using the term, and in future it will be referred to as an evolving capacity market. Mr. Butters expressed concern that the transitional capacity auction would morph into the larger incremental capacity auction. Mr. Gregg stated that the plan is not for the transitional capacity auction to evolve back into an incremental capacity auction and will work with stakeholders on other procurement mechanisms on capacity. Mr. Butters said the addition of alternative procurement mechanisms is a good idea. Also, the cost-benefit analysis is important going forward. Mr. Gregg said consultations around who should own the risks would take place. Mr. Butters said Enbridge and APPrO met with the IESO in July to discuss the challenge of electricity and natural gas alignment. It is important to make them work together. The shorter the commitment period, the more difficult it is to align them.

Mr. Paul Norris said it is important to keep an eye on the assumption that resources on the ground now will continue to operate. Mr. Gregg agreed.

Ms. Ingram said capacity auctions must be open and transparent and provide a level playing field. There is a concern that the proposed market rule amendments for the TCA do not provide a level playing field. Mr. Gregg said the IESO would continue to address this concern.

Mr. Schembri asked how the market performed this summer. Mr. Gregg said it was reliable and served the province well.

Ms. Malini Giridhar asked if natural gas capacity is considered in integrated regional planning. Mr. Gregg said it is and will receive additional attention with Steve Baker's appointment to the Board.

<u>Agenda Item 4. Market Renewal – Energy Update</u>
Ms. Barbara Ellard

Ms. Ellard said the energy market is nearly 16 years old. Technological change has been significant, as evidenced by the arrival of electric vehicles, DERs, storage, and prosumers.

The past 16 years have revealed flaws and associated higher costs within the energy market. Day-to-day operating profiles have begun to change and there is a need to find a better way to commit, dispatch, and price to ensure reliability and cost-effectiveness.

The final High Level Designs are published. The fundamental flaw of the current market is that the market price is not reflective of system conditions. The price ignores transmission constraints, congestion, and operational constraints, for example. Out-of-market payments are required to ensure reliability. Ontario's two-schedule system has prevented the IESO from making improvements. While incremental changes have been made, locational prices are needed to evolve the market more significantly.

In addition to pricing, dispatch and resource scheduling also needs improvement. The energy work stream will introduce a day-ahead market, providing financial incentives to secure the next day's operational profile. It will also introduce real-time unit commitment and a single-schedule market.

Feedback on the High Level Design has been generally supportive. Areas of concern expressed by stakeholders include zonal pricing for loads, how to align market changes with contract changes, and implementation risks for LDCs.

Stakeholders expressed concerns on the load-pricing component of the design. After consulting with AMPCO about risk management, the IESO has proposed choosing between an Ontario zonal price and a nodal price, and this has been reflected in the updated High Level Design.

Stakeholder engagement on the detailed design will take place this fall.

The energy business case will focus on quantifying unit commitment and dispatch, as well as pricing flaws within intertie transactions and dispatch. Modeling results and cost estimates will be discussed at the Market Renewal Plan (MRP) stakeholder update on August 26. Response to the feedback and final business case will take place in September, to be wrapped up in October.

Comments

Mr. Bentz asked, with respect to moving to locational/marginal pricing, what behaviours are expected by sending a different pricing signal to the market? He asked what the impact would be on the retail consumer. Ms. Ellard said having price signals that are reflective of the system conditions would elicit a better response from suppliers and consumers. People may not currently have the right incentives to ensure competitive bidding. The Market Surveillance Panel has documented that there is an opportunity for gaming, and locational prices will eliminate this. Mr. Bentz asked if there would be a net cost saving. Ms. Ellard said total system cost would be reduced. Regulated price plan (RPP) consumers are expected to stay on an RPP pricing regime, based upon the average Ontario zonal price.

Ms. Giannetta asked when stakeholders will have a better understanding of the detailed design and what are the next steps for market amendment impacts with respect to contracts. Ms. Ellard said the detailed design schedule will be outlined at the August 26 MRP meeting. The IESO will continue to work in unison with the contract team to ensure cohesion.

Ms. Girvan asked what changes were made in response to concerns expressed by AMPCO. Are there implications for other customers? Ms. Ellard said one concern was that with respect to volatility that might arise from zonal pricing. As to the impact, an average uniform price would be lower for some zones.

Mr. Colin Anderson said AMPCO was concerned about trade-offs between short- and long-term economic efficiency. Eight of the 10 zones were going to pay more than an average price. There was concern with respect to risk management. AMPCO members are paying a lot and cannot afford additional upward pressure. Locational marginal pricing (LMP) is seen as a risk with no corresponding return and no way to mitigate it. After fruitful discussions with the IESO, AMPCO is satisfied that the optionality of the new proposal as that would allow the vast majority of industrials to pay an average price going forward. AMPCO was thankful to the IESO having provided the alternative load pricing proposal.

Ms. Ellard said impacts on other consumers will be marginal and costs will come down for all consumers.

Mr. Hogan noted that the OEB approves final RPP rates. He asked if there is a plan to work with OEB? Ms. Ellard said the IESO has worked with the OEB throughout the High Level Design phase and this will continue through the detailed design phase.

Mr. Schembri noted that if AMPCO is happy with the zonal pricing, it could be assumed that Class B consumers will be negatively impacted. Ms. Ellard said the system costs through all of the MRP changes would be reduced for all customers. The change in the load pricing design has a marginal impact on non-Class A customers. Mr. Schembri asked if these efforts would result in an increase in the hourly Ontario energy pricing (HOEP) and reductions to global adjustment pricing. Ms. Ellard replied that it is difficult to forecast but that some design elements may provide downward pressure on market prices.

Mr. Anderson added that AMPCO's participation in market renewal is to find reductions in cost. What is good for AMPCO members may be good for other people. Class B members would benefit just as much or more than Class A members.

Mr. Jesus asked how the changes would affect transmission and what signals will be sent to transmitters from an outage planning perspective. Second, how will the signals affect new customers wanting to locate in Ontario? Ms. Ellard said the system is currently dispatched based on reliable operations and that the changes will not affect how we dispatch the system from a transmission perspective. The changes are focused on scheduling and pricing. The result will be more transparent price signals, and congestion will become more visible. Mr. Jesus asked if the signals would encourage transmission development. Ms. Ellard said this has been seen in other jurisdictions.

Agenda Item 5. Market Renewal – Capacity Update
Mr. Terry Young, Mr. Leonard Kula, Mr. Chuck Farmer

Mr. Farmer provided a preliminary look at the assessment around the upcoming annual planning outlook to be released later this year. Mr. Farmer focused in on the slides that outline that we are energy adequate but we have some capacity requirements. The IESO does not see a need for new build for reliability reasons. The need for additional capacity would emerge in the year 2023 when the phase-out of the Pickering nuclear plant begins. This will translate to a need for 1000-2000 MW over the longer-term if the existing resources remain. If existing resources do not remain, significantly more capacity will be required.

The energy adequacy outlook considers Ontario as an isolated system, without imports. It shows adequacy for the next 20 years if existing resources continue to participate. If existing resources do not renew at the end of their contracts, the gas fleet will fill any potential shortfalls until 2028 when significant needs would emerge. Therefore, throughout the next decade the requirement is for resources that run very little. They will be there for extreme weather events and unforeseen conditions. Overall, a 1% increase in demand is expected.

Comments

Mr. Norris said the assumption that all resources continue to operate is difficult given that capital investment decisions must be made now for 2029-2030. Mr. Kula said a short-term commitment mechanism works well for imports. Long-term capital investments require alternative mechanisms. The challenge is in determining when is a good time for resources to exit, and whether they should exit. Mr. Kula went on to state in response to n earlier comment from Mr. Butters that the IESO will facilitate this while ensuring alignment of electricity and gas. With respect to cost-benefit analysis, it is necessary to think of system cost outside of the cost of the resource. For example, on each of the five peak days so far this year, base load resources have been spilled, including water, wind, and nuclear resources. Upwards of 1000 MW have been spilled at 3 a.m.

Mr. Young said monthly update meetings associated with market renewal would continue over the next 18 months. Phase 1 rules for the capacity stream were dealt with at yesterday's TP meeting, and Phase 2 is to begin within a few days. This will be followed by a discussion of the annual planning outlook and how to meet identified needs.

Mr. Bentz expressed concern about the forecast assumptions on the demand side in the face of an increasingly volatile market which will see the arrival of cannabis operations, data centres, DERs, fuel switching, electric vehicles, mass transit, and generators coming off contract. He asked if it would make sense to have a band of values as opposed to a straight line on the planning outlook graph. Mr. Farmer said electric vehicles would not shock the system over the next 10 years. He worries more about risks caused by economic change. The global economic crisis of 2008 was highly impactful. Mr. Bentz asked if Metrolinx initiatives have been considered. Mr. Farmer said they have.

Ms. Judy Dezell noted that studies indicate people are charging electric vehicles during high-peak rather than low-peak times, and asked how the IESO will work to manage human behavior? She asked how climate change is modeled. Mr. Farmer said customers will be encouraged to charge their vehicles at night. High-peak charging and concentration of EV adoption will be impactful to LDCs, but will not significantly impact the overall system. Factoring in climate change impacts remains a weakness in forecasting that the IESO seeks to address.

Ms. Giannetta supports the needs for the long term reliability needs engagement. Mr. Giannetta said wind generation is not an *ad hoc* process so decisions need to be made now for adding future capacity. Acquiring capacity does not have to be done on an individual basis; bilateral contracting is coming. Mr. Kula said in the absence of a robust buyer community, it is difficult to facilitate bilateral contracting.

Mr. Bentz said with respect to bilateral contracts, industrial customers are looking at one-off cogeneration facilities or reciprocating gas engines to curtail what the grid sees as demand. This is a growing trend and presents a potential risk in terms of asset utilization. He asked how this is factored into the forecast. Mr. Farmer said behind-the-meter generation is a blind spot. The IESO forecasts on a net and grid level. Mr. Bentz noted that the Ontario Energy Board is conducting a review of connecting facilities behind the meter.

Agenda Item 6. Demand Response Working Group Update
Ms. Candice Trickey

Ms. Trickey highlighted progress on the revised DR work plan.

There are two initiatives concerning payments when DR resources are activated in the market. The first is compensation for out-of-market activation of hourly DR resources. By the next auction it is expected they will be provided compensation when they are activated for a test. Market rules will be developed this fall. The second initiative is to determine whether or not to provide energy payments for economic activation of DR resources. While this is a rare occurrence we recognize that it is an important one to the DR community. The FERC ruling says that if there is a net benefit to consumers to activating that resource and giving them an energy payment then they should receive an energy payment. Ms. Trickey outlined that the IESO is looking into this but that it needs to take time to understand the implications and to get this right. A draft on the scope, approach, and timeline for this initiative will be provided at the September 4 meeting of the Demand Response Working Group.

Comments

Ms. Ingram said her constituents are supportive of the conversations and progress on out of market payments. Ms. Ingram said the subject of energy payments has been raised consistently since the beginning of the DR auction and it is disappointing that it is not yet resolved. The currently proposed rules are discriminatory against DR participants. Generators will be entitled to energy payments and DR participants will not. A legal brief will be provided to the IESO Board before a decision is made. This will not be resolved by the December auction, so discrimination will happen there. Ms. Trickey said in all likelihood any activations will be test activations, not economic activations. Ms. Ingram said it would make sense to get the rules for the capacity auctions right at the beginning, not to fix them later on.

Mr. Schembri asked how many DR calls there have been outside of tests this year. Ms. Trickey said there have been none.

Mr. Anderson echoed Ms. Ingram's concern about discrimination in the proposed rules and asked if they could be resolved before pushing ahead with the December auction. There is no significant capacity requirement for the next decade, and no urgency. Mr. Young said the IESO is taking a phased-in approach and notes that the December date for the capacity auction is important to this approach.

Agenda Item 7. 2020-2022 Business Plan
Ms. Barbara Anderson

Ms. Anderson summarized the five-year strategic plan. Refreshments have been made to the purpose and vision. There are five key strategic objectives:

1. culture and workforce transformation
2. competitive marketplace
3. reliability

4. stakeholder value perception
5. prioritized spending

six risks have been identified: policy and regulatory uncertainty, particularly around the competitive marketplace; government stakeholders losing faith in the IESO approach to deliver on resource adequacy; frequency and complexity of cyber attacks; extreme weather events; scarcity of skilled human resource talent to support the needs of the sector; and non-electricity entrants, where the Googles and Amazons potentially cause disruption. Mitigation strategies have been developed for all of the identified risks.

With regards to the business plan, revenue requirement levels were flat from 2017 to 2019. A 2% annual increase for the next three years has been suggested, in line with the Consumer Price Index. The increase will allow for investment in cyber security enhancements, efficiency of the markets, working with stakeholders on enduring mechanisms for resource adequacy, and ensuring reliability is maintained in a cost effective manner.

Comments

Mr. Bentz asked what is meant by potential risks posed by Google or Amazon. Ms. Anderson said any non-electricity entrant could disrupt the market.

Mr. Scongack asked if the winding down of the ICA could bring about a net benefit to the overall revenue requirement. Ms. Anderson said most of the capital is financed and does not come through the IESO fee.

Mr. Hogan said customers and service providers want to know what will happen after 2020 when the conservation programs are completed. Mr. Young said discussions on this will begin soon.

Mr. Butters asked for clarification as to whether the TCA will become the preferred method for capacity procurement. Ms. Anderson said the capacity team is stratifying the resources and looking at the risk profile for each to determine the correct mechanism. Capacity auction is one option of many that will be investigated over the course of 2020.

Comment from the Phone

With respect to conservation efforts, Mr. David Katz said deep retrofits required by decarbonization include electricity and gas. The duality should be reflected to ensure economic sense. Mr. Young said this would be considered post-2020.

Agenda Item 8. Other Business

There was no other business.

Agenda Item 9. Adjourn

Mr. Bentz adjourned the meeting. The next meeting will take place on October 16, 2019.

TAB 3

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. Other Considerations:

- 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.

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO)

Response to Staff #2

Reference: (FERC) Order No. 745 Demand Response Compensation in Organized Electricity Markets, March 15, 2011, paragraphs 24, 25, 28, 42, 43, 57, 60, 63, 103, 104, footnote 199, paragraphs, 105, 107, 108, footnote 208, paragraphs 110, 111, 114.

Reference Commissioner Moeller's dissenting opinion page 4, paragraph 3; page 4, footnote 11; page 5, paragraph 2; page 5, footnote 12; page 7, paragraph 1; page 7, footnote 21, page 8, paragraph 1, page 8, footnote 26; page 8, footnote 27; page 8, footnote 29; page 9, paragraph 1; page 9, footnote 33; page 10, paragraph 1.

Preamble:

The paragraphs and footnotes listed in the reference above deal with how FERC's decision relating to the payment of LMP for demand response activations interacts with the fact that many potential demand responders in the electricity markets under FERC's jurisdiction pay state-level regulated retail rates for the energy they consume. This appears to be quite different as compared to the Ontario electricity market where potential demand responders typically pay either the market clearing price determined in the Real Time Energy Market (for Class A loads), or the Hourly Ontario Energy Price (HOEP) plus a volumetric charge for Global Adjustment (for Class B loads).

The contrast between the U.S. discussion and the Ontario discussion suggests differences in how demand responders participate in the IESO-administered markets in Ontario as compared to similar demand responders in U.S. FERC-regulated electricity markets.

Questions:

(a) What differences between demand response participation in energy markets in the U.S. and in Ontario are you aware of?

(b) Are any such differences relevant to the question of energy payments for the economic dispatch of demand response resources in Ontario? If so, why?

Response:

AMPCO does not have particular expertise in the nuances of energy markets, and DR resources participation within those markets, in the various FERC regulated US jurisdictions (which are PJM Interconnection (PJM), New York Independent System Operator (NYISO), New England ISO (ISO-NE), Midcontinent ISO (MISO), Southwest Power Pool, (SPP) and California ISO (CAISO)). Questions on particular market differences between one or more of these markets and the Ontario electricity market might be best addressed by the IESO.

There are two issues discussed by FERC in the various paragraphs referenced in connection with this question in respect of which AMPCO can contribute its view:

1. The relevance of the fact that some of in the U.S. jurisdictions considered large electricity customers pay retail rather than wholesale market rates.

2. Whether DR resources would be overcompensated by receiving energy payments set at what FERC refers to as the full “locational marginal price” (LMP), rather than receiving energy payments of LMP-G where G is the retail electricity cost avoided by the DR resource operator.

Related to these two issues is the importance, in AMPCO’s view, of the “net benefits test” adopted by FERC in order to ensure that compensation of DR resources with energy payments provides a benefit to electricity consumers (i.e. reduces overall electricity costs).

In respect of the first issue – the relevance of the fact that in some of the U.S. jurisdictions considered large electricity customers pay retail rather than wholesale market rates – the implication of this difference that has been suggested in the context of considering energy payments for DR resources is that, in these U.S. jurisdictions, but for the energy payments the DR resource operators would not be responsive to wholesale market prices. In Ontario, where large electricity customers pay real time energy market prices, they have direct price signals which influence their consumption choices and behaviours, even without energy payments.

The second issue – the impact of avoided energy costs on appropriate energy payments to DR resources – relates to theoretical optimization of economic efficiency.

FERC addressed both of these issues in examining the appropriateness of energy payments for DR resources from the perspective of the market, not the individual customer. At paragraph 62 of its March 15, 2011 decision FERC stated:

> *In the absence of market power concerns, the Commission does not inquire into the costs or benefits of production for 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," notwithstanding the particular costs of production of individual resources. Commenters have not justified why it would appropriate for the Commission to continue to apply this approach to generation resources yet depart from this approach for demand response resources.*

In the result, FERC found [paragraph 47, page 39] it appropriate to pay demand response resources *LMP "in order to compensate those resources in a manner that reflects the marginal value of the resource to each RTO and ISO"*, and thus in order to *"result in just and reasonable rates for ratepayers".*

FERC went on to qualify its finding by requiring that two conditions be met to establish the appropriateness of compensating DR resources at the wholesale energy price (LMP in those jurisdictions) for the service provided [page 39, paragraph 42]. These two conditions are that;

1. the DR resources have the capability to provide the service, i.e. to displace a generation resource in a manner that serves the RTO or ISO in balancing supply and demand; and

2. payment of the LMP for the provision of the service by the DR resources must be cost-effective, as determined by the net benefits test described.

A properly constructed net-benefits test was required by FERC in order to [page 3, paragraph 3]:

> *… ensure that the overall benefit of the reduced LMP that results from dispatching demand response resources exceeds the cost of dispatching and paying LMP to those resources*. *When the net benefits test described herein is satisfied and the demand response resource clears in the RTO's or ISO's economic dispatch, the demand response resource is a cost-effective alternative to generation resources for balancing supply and demand.*

From AMPCO's perspective a properly constructed and applied, Ontario specific, net benefits test is required in order to ensure that a demand response resource will only be paid for energy in a situation where it is cost-effective from the market's perspective (i.e. the consumer's perspective) for that resource to be utilized. This means that the interests of all consumers are served by implementing energy payments because the utilization of the specific demand response resource in question is the most economically efficient action that can be taken to satisfy the need. A properly constructed net-benefits test would take into account any Ontario specific considerations to ensure such a result (such as, for example, out of market settlements and the Global Adjustment).

If the net-benefits test is not passed, no energy payment is made.

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO)

Response to Staff #3

Reference: Transitional Capacity Auction, Phase I Design Document, June 5, 2019, p.11.

Preamble:

The IESO's Phase I design document for the TCA describes the different approach in relation to the dispatch of dispatchable load resources and non-dispatchable load resources, which are referred to as Hourly Demand Response (HDR) resources. That document notes dispatchable load resources deliver energy by following the IESO's five-minute dispatch instructions. In contrast, HDR resources receive a "standby report" in advance of a potential activation between 15:00 EST day-ahead until 07:00 EST on the dispatch day, if they were scheduled to curtail. HDR resources would then be notified that they will be dispatched by receiving an Activation Notice about 2.5 hours before the start of the first dispatch hour. Dispatchable load resources are therefore subject to the same requirements as generators (i.e., 5 minute dispatch), while HDR resource requirements are not.

AMPCO does not distinguish between the different types of DR in the application (i.e., dispatchable and not dispatchable).

Questions:

(a) Is AMPCO's position that all DR resources should be eligible to receive an energy payment?

(b) If so, given the differences between dispatchable and non-dispatchable loads discussed above, please explain why HDR resources should receive the same treatment as dispatchable load resources in relation to receiving an energy payment.

Response:

(a) Yes.

(b) Demand side resources that are activated for energy will all incur costs, examples of which are provided in AMPCO's response to Board Staff Interrogatory 1. Those costs are not dependent on whether the load in question is dispatchable or is an hourly demand response resource. For this reason, they should all be considered eligible for energy payments in a situation where they are activated and providing the requisite service to the market and displacing a generation resource, provided the appropriately derived and applied Ontario specific net-benefits test is passed.

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO)

Response to SEC #3

Preamble:

SEC wishes to better understand the impact on ratepayers of the Market Rule amendments at issue, and AMPCO's position that Demand Response providers should be eligible for energy payment.

Question:

Please provide AMPCO's views, including copies of any analysis that it has undertaken or is aware of, regarding impact on costs that will ultimately be borne by Ontario ratepayers of providing energy payments to Demand Response providers.

Response:

AMPCO has not undertaken any analysis on this issue.

In AMPCO's view which includes consideration of the perspectives of the majority of AMPCO's members who are not DR resource providers and for whom the lowest possible electricity costs are of paramount importance, the interests of Ontario consumers would be fully and appropriately protected by the development and application of an Ontario specific "net benefits test", as was required by FERC as a pre-condition to energy payments for DR resources. Please see AMPCO's response to OEB Staff interrogatory 2.

In AMPCO's view, this is the primary issue which the IESO's now launched [Affidavit of David Short dated October 25, 2019, paragraph 21-27 and Exhibit K] stakeholder engagement on energy payments for DR resources should be focussed on.

TAB 4

1.2 KCLP-2

Interrogatory

Reference: LEI Report, section 3.2.2, pp. 10-11

Preamble: The LEI Report states that Figure 5 presents for illustrative purposes PJM's monthly NBT prices from April 2012 to October 2019, along with the monthly average prices for PJM – RTO Zone. It states that the chart is illustrative as the test is actually applied to each applicable zone on an hourly basis.

Questions:

(a) Can you confirm that the net benefits test price threshold in PJM is calculated monthly using a system-wide monthly supply curve that is smoothed using non-linear estimation techniques?
(b) Can you confirm that this singular system-wide threshold is compared to the various locational marginal prices (LMPs) on an hourly basis to determine DR resources are eligible for compensation?
(c) In your opinion, are there any shortcomings of applying this system-wide threshold to hourly LMPs for determining a net benefit to consumers from compensating DR resources?
(d) Would you recommend the same approach be applied to Ontario? If yes, why and if no, why not?

Response

(a) As laid out in PJM's *Manual 11: Energy & Ancillary Services Market Operations, Revision: 107,* Section 10.3.1 (effective September 26, 2019), the aggregate supply curve for PJM is smoothed using a non-linear least squares estimation technique.

(b) The system-wide threshold is compared to applicable LMPs; this can be on an hourly basis (e.g. in the case of the day-ahead market) or on a five-minute basis (e.g. in the case of the real-time market).

(c) Yes. Comparing the LMPs to a system-wide threshold poses a degree of administrative burden on market institutions, while potentially oversimplifying net benefit calculations given the possible diversity in how load to customers is priced and the nature of their financial hedges, among other factors.

(d) No. We do not believe that Order 745 is relevant to the specifics of the Ontario market. Any test developed for Ontario should at a minimum take into account Ontario-specific conditions, including the Global Adjustment and how it is recovered, as well as more generally how supply is priced to various types of load in Ontario and over what time period, and the expected evolution of the Ontario market.

1.4 KCLP-4

Interrogatory

Reference: LEI Report, Section 3, Pages 7-14

Rivard Affidavit, Paragraphs 56-58

Preamble: At section 3 (pages 7-14) of the LEI Report, LEI provides an overview of FERC Order 745 and the net benefits test.

At paragraphs 56-58 of the Rivard Affidavit, Mr. Rivard draws a distinction between the net benefits test and economic efficiency.

Questions:

(a) Please identify any points on which LEI is in agreement with, or disagrees with, Mr. Rivard's assessment of the net benefits test and economic efficiency. If LEI generally agrees with Mr. Rivard, please confirm this.
(b) If LEI disagrees with any aspect of Mr. Rivard's assessment, please explain the basis of this disagreement.
(c) Based its research conducted, has LEI formed an opinion regarding the economic impacts of providing energy payments to DR resources? If yes, please state the opinion.
(d) Is LEI of the opinion that providing energy payments to DR resources could lead to economically inefficient outcomes both during the TCA, and in the event that a DR resource is dispatched? Please explain.

Response

(a) LEI's disagreement with the assessment of the net benefits test lies primarily with regards to its relevance to the Ontario situation. 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 to the concept of horizontal equity.

However, LEI agrees that any consideration of whether and how market rules are developed to incorporate an activation payment must take into account the incentives Class A customers receive under the ICI to adjust their consumption.

(b) LEI believes that the discussion of horizontal equity is over-simplified. Fossil generators are not expected to guess how many times they will operate and at what fuel price, and to incorporate those assumptions into their capacity bids because they will not be paid an energy price when run. While the theoretical premise is that generators will reduce their capacity bids by the margin above fuel costs that they expect to achieve, generators do expect to receive at least their short run marginal costs when dispatched, and configure their bids accordingly.

A framework in which DR receives only capacity payments but no activation payments will drive DR participants to set high activation price thresholds. This may dull the effectiveness of the price signal at relatively high price periods (such as periods when the market price is high, but remains below the DR activation threshold). Short run costs of activation include process wastage (for example disposing of unfinished and unfinishable products) and staff inefficiencies; allowing compensation for these costs rather than expecting companies to factor them in to their activation threshold (i.e. the price trigger at which load would be curtailed) is more consistent with horizontal equity in that it is equivalent to generators being paid for fuel and other short run variable operating costs through their energy bids.

(c) Given the short time period in which to develop its analysis and respond, LEI's opinions are preliminary and subject to change. With that caveat in mind, LEI's views are as follows:

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 DR capacity revenues, see Section 4.4 of LEI's report). 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.

LEI's understanding is that the IESO's proposed design is the subject of this proceeding and alternative approaches are not within the scope of the case. Nevertheless, LEI believes that, conceptually, there is merit in separating the reservation payment embodied in a capacity payment from an activation payment which occurs when the resource is actually deployed. In such a market design, bidders into the capacity auction need not consider the frequency of deployment or build in a risk premium when submitting their capacity bid. Were market rules devised which allowed a two part bid from DR resources in which they set forth both their required activation payment and the activation price threshold, DR resources would receive a payment, and their DR activation bids would reflect both the benefit of avoiding a cost and the cash payment required to address specific costs of activation. LEI believes that such an approach would result in greater variation of DR activation bids leading to a more robust price signal. LEI also notes that behavior responses to avoidance of cost versus those to receipt of a benefit may differ; creating a hybrid of the two may produce more economically efficient outcomes.

(d) LEI believes that any assessment of economic efficiency needs to be based on the specific market rules being applied, and the period of time being analyzed. Furthermore, the fact that something ***could*** happen does not mean that it ***will*** happen; analysis needs to take into account probability, frequency, the degree of harm, safeguards, and net benefits before coming to a determination.

1.6 KCLP-6

Interrogatory

Reference: LEI Report, Section 5, pages 33-39, Rivard Affidavit, Paragraphs 58-71

Preamble: At Section 5.4 (pages 37-38) of the LEI Report, LEI identifies the impact of Global Adjustment in Ontario, which according to Figure 30 accounts for 77% of the total electricity wholesale costs (excluding transmission and distribution costs) in Ontario.

At paragraphs 58-71 of the Rivard Affidavit, Mr. Rivard provides an analysis of the impact of Global Adjustment on the calculation of the net benefits test in Ontario.

(a) Does LEI agree with Mr. Rivard that if the intent of the FERC net benefit test is to compensate DR resources only when it results in a reduction in the bills of non-DR consumers (non-DR consumers' surplus), then the IESO would have to take into account the effect of the Global Adjustment in this calculation in Ontario?
(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 US markets?
(c) With specific reference to paragraphs 58-71 and Figures 5, 6 and 7 of the Rivard Affidavit, please explain whether LEI generally agrees or disagrees with Mr. Rivard's analytic approach and Mr. Rivard's findings?

Response

(a) Yes; however, as Ontario is not under FERC jurisdiction, and the market framework has significant differences, the test is not relevant.

(b) LEI does not believe that the net benefits test as configured for US markets is appropriate for developing market rules in Ontario. Due to the generally inverse correlation between Ontario wholesale market prices and the Global Adjustment, there are some changes to Ontario market rules which could improve transparency and change wholesale price outcomes without having an immediate bill impact. However, such rule changes could still incentivize changes to investment and operating behavior which over the long run would still provide benefits to consumers.

(c) Because LEI questions whether the net benefits test as configured for US markets is relevant to Ontario, LEI regards the analysis as largely academic. LEI nonetheless has the following observations:

1. The analysis is largely static; it does not assess how the behavior of various market players would change as a result of the changes in market conditions.
2. Using historical data is a beginning, rather than an end, to the analysis; consideration of future changes in price dynamics is helpful in exploring the impact on final consumers.
3. Changes that impact even a very small number of overall hours may nonetheless be worthwhile, to the extent that they improve the value of the price signal during super-peak hours.

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4. The analysis may be targeted at the wrong question: a better question is, under what circumstances would providing energy payments to demand response be beneficial for Ontario, and what tests should be designed to confirm that those circumstances prevail at the time?
5. LEI believes that Ontario should pursue a pragmatic approach based on sustained incremental improvements to market rules, which where appropriate is substantiated by dispatch modeling and scenario analysis.

TAB 5

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

Ontario

Monitoring Report on the IESO-Administered Electricity Markets

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amendment to accommodate other priorities, and that it would provide another update once new implementation timelines are established.[69]

4 New Market Mechanisms to Procure Capacity

The IESO is planning to introduce new market mechanisms for procuring additional capacity to meet future system needs. Over the course of 2015, the IESO has advanced initiatives in this direction: capacity auctions for demand response (DR), as a first stage in the development of capacity auctions for other resources, and the consideration of capacity exports to other jurisdictions.

The IESO held its first capacity auction for DR in December 2015 for delivery starting in the summer of 2016. This first auction had a target of 367 MW, equal to the capacity expiring from the IESO's current DR programs. The outcome of the auction was the award of DR capacity to seven of the seventeen registered participants, for 391.5 MW of capacity at a price of $378.21/MW-day in the summer (May 1 to October 31) and 403.7 MW of capacity at a price of $359.87/MW-day in the winter (November 1 to April 30).[70]

The IESO plans to hold DR auctions once each year to procure capacity for two six-month commitment periods— summer and winter. Registered DR auction participants will bid their capacity and the availability payment they will accept, and the IESO will clear the market (in several zones across the province) with a downward sloping demand curve for each commitment period.

Participants who clear the auction will be required to offer into the real-time market as DR resources, and will receive a monthly availability payment equal to their capacity times the clearing price times the number of business days in the month. Participants who respond to the dispatch will save the energy costs when they are activated to provide DR. Activations of these DR resources is expected to reduce peak demand.

The DR capacity auction is intended to be the first phase of the IESO's efforts to introduce capacity markets for all resources. The IESO conducted several information sessions on this

[69] For more information see the IESO's October 9, 2015 stakeholder communication, available at: http://www.ieso.ca/Documents/consult/se111/SE111-20151109-Communication.pdf
[70] For more information see the IESO's Demand Response Auction webpage, available at: http://www.ieso.ca/Pages/Participate/Demand-Response-Auction/default.aspx

topic over the course of 2014, and published details of design elements in a September 18, 2014 Discussion Paper.[71] The Discussion Paper describes the role of a capacity auction as enabling "all resources to compete on a frequent basis to meet the province's future incremental resource adequacy needs". Although the IESO has not committed to firm implementation timelines for the capacity auction, the development of detailed design elements and the launch of the DR auction have set the groundwork for further market development in this area.

In November 2010, the Minister directed the IESO (then the Ontario Power Authority) to enter into negotiations with non-utility generators (NUGs) for new contracts. In December 2014, in light of changing supply conditions, the Minister directed the IESO (then the Ontario Power Authority) to suspend any pending negotiations with NUGs and prepare an assessment of the framework for NUG recontracting in the Province, having regard to a number of considerations including the IESO's work to develop a capacity auction in Ontario. The IESO's September 1, 2015 report to the Minister of Energy recommended that the current pause on recontracting with the NUGs be continued given the current strong supply outlook and pending clarification of evolving sector conditions.[72] The IESO identified the continued operation of the Pickering nuclear generating station, the development of the capacity auction and capacity export opportunities, and the introduction of cap-and-trade legislation as potential changes in the sector that would have a bearing on recontracting efforts. The IESO also recommended that the development of the capacity auction and capacity export markets be continued with consideration given to facilitating broad participation, including by the NUGs, as a more effective means of meeting future resource needs. By letter dated December 14, 2015, the Minister of Energy directed the IESO to discontinue negotiations for new contracts for NUGs and to continue engaging stakeholders in the IESO's development of an Ontario capacity auction and rules and protocols for Ontario-based capacity exports.[73]

Capacity markets in some other jurisdictions accept exports of capacity from neighbouring jurisdictions. Beginning in 2015, the IESO opened a stakeholder engagement on the subject of

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[71] For more information see the IESO's September 18, 2014 Discussion Paper, available at: http://www.ieso.ca/Documents/consult/capacity-20140918-Design_Element_Discussion_Paper_Agenda.pdf
[72] For more information see the IESO's NUG Framework Assessment report, available at: http://www.ieso.ca/Documents/generation-procurement/NUG-Framework-Assessment-Report.pdf
[73] For more information on the Minister of Energy's December 14, 2015 Directive, see: http://www.ieso.ca/Documents/Ministerial-Directives/2051214-Directive-NUG_CHPSOP_ChaudiereFalls_WhitesandFirstNation.pdf.

capacity exports. This IESO continues to work towards establishing the market need for such a program, assessing the feasibility and timeline of implementation, and continues to engage with stakeholders.[74]

5 Developments Relating to Ontario's Interconnections

Several developments during this reporting period have had or will have an impact on the IESO's interconnections with other jurisdictions. These include a seasonal electricity capacity sharing agreement with Québec, discussions around enhancing trade in electricity products with Québec and Newfoundland and Labrador, and ongoing developments in the proposed interconnection between the Ontario and parts of the United States that fall within the jurisdiction of PJM.[75]

The capacity sharing agreement between the IESO and Hydro Québec Energy Marketing is in force from December 1, 2015 to September 30, 2025.[76] Ontario has an initial two year obligation to provide 500 MW to Québec during the first two winter periods (December to March), with an option to reduce the quantity after that time. Ontario may elect to receive up to 500 MW from Québec in any given summer period (June to September). Québec's obligation is to "repay in kind the equivalent amount of capacity it received in the winter periods to Ontario in the summer periods." The capacity is to be shared "like for like", with no monetary exchange. The jurisdiction receiving the power must make a "Reliability Declaration", which in Ontario will be made when there is a shortfall in the market. If Hydro Québec makes a Reliability Declaration, it will be responsible for scheduling an export transaction in the IESO-administered market, which will clear based on the economics of the bid.[77]

The IESO is also planning to study and provide reports on expanding trade in electricity between Ontario and Québec, and between Ontario and Newfoundland and Labrador. This is in response to the April 22, 2015 direction from the Minister of Energy to investigate "other opportunities to obtain electricity products from Hydro-Québec, and other Market Participants, where the

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[74] For more information, see the IESO's stakeholder engagement webpage at: http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/Capacity-Exports.aspx.
[75] PJM is a regional transmission operator that coordinates the movement of wholesale electricity in the USA in all or parts of 13 states and the District of Columbia. For more information on PJM, see: http://www.pjm.com/.
[76] For more information see the IESO's summary of the agreement, available at: http://www.ieso.ca/Documents/corp/Summary-Capacity-Sharing-Agreement-Ontario-Quebec.pdf
[77] For more information see the IESO's backgrounder, available at: http://www.ieso.ca/Documents/Ontario-Quebec-Capacity-Sharing-Agreement-Backgrounder-20151112.pdf

TAB 6

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

Ontario

Market Surveillance Panel

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other jurisdictions have developed objective and open processes for assessing these competing priorities. A similar approach should be considered in Ontario.

Matters to Report in the Ontario Electricity Marketplace

Assessment of the IESO's Demand Response Auction

Since 2004, the Government of Ontario has been mandating the development of electricity conservation programs. The primary aim of these programs is to alleviate the need to build new generation facilities by reducing demand during peak periods. Demand Response (DR) programs, which incent consumers to reduce consumption during periods of high prices, high demand or tight supply, have been a large part of that conservation effort.

The IESO is responsible for achieving the conservation related policy goals set forth by the Ministry of Energy. Prior to 2015, bilateral contracting was the primary means of procuring the necessary DR resources to meet policy objectives; in 2015, the IESO developed the DR auction. The DR auction introduced a competitive, flexible and transparent process for procuring DR resources, where formerly there was none. DR resources procured in the 2016 and 2017 DR auctions will be paid up to a total of $73 million; these payments are recovered from Ontario consumers by uplift charges.

The resources procured through the DR auction are intended to help meet the Ministry of Energy's conservation policy goals. However, for the reasons explained in detail in Chapter 4 of this Report, it is unlikely that the current DR program will actually contribute to conservation or demand reduction. Briefly, this is because the rules associated with the DR auction establish thresholds for activation which have not been realized to date and are unlikely to be realized in the future.

Having said that, the Panel also questions the need for peak shaving DR capacity at this time as Ontario has sufficient resources to meet peak demand in the province for the foreseeable future.

Recommendation 4-2:

The IESO should reassess the value provided by the capacity procured through its Demand Response auction in light of Ontario's surplus capacity conditions, as well as the stated

The Panel expands on the interdependencies between each component of the TR Clearing Account from section 3.1.1 to section 3.1.2 of Chapter 4.

Table 2-6: Demand Response Auction Results in December 2015 (MW, \$/MW-day)

Description

Table 1-6 summarizes the results of the IESO's inaugural Demand Response (DR) Auction, completed in December 2015 for the subsequent summer (May 1, 2016 to October 31, 2016) and winter (November 1, 2016 – April 30, 2017) commitment periods. In general, DR consists of programs that encourage customers to reduce demand during times of tight supply conditions. DR is meant to reduce the total peak demand, or be used at other times to assist with maintaining reliability, as an alternative to calling on generators to produce more energy. As specified by the capacity obligation within each zone, resources committed through the DR auction are available to provide relief by reducing their consumption when called upon. Successful resources from the DR auction receive the auction clearing price for each MW of DR capacity.[36]

Zone	Summer Commitment Period (May 1, 2016 - Oct 31, 2016)		Winter Commitment Period (Nov 1, 2016 - Apr 30, 2017)	
	Capacity Obligation (MW)	Auction Clearing Price (\$/MW-day)	Capacity Obligation (MW)	Auction Clearing Price (\$/MW-day)
BRUCE	-	-	-	-
EAST	24.7	378.21	25.4	359.87
ESSA	13.7	378.21	13.8	359.87
NIAGARA	15.9	348.45	15.9	332.71
NORTHEAST	56.3	378.21	56.3	359.87
NORTHWEST	51	378.21	50	359.87
OTTAWA	10.8	378.21	11.2	359.87
SOUTHWEST	40	378.21	55.3	359.87
TORONTO	159.4	378.21	159.2	359.87
WEST	19.7	378.21	16.6	359.87
Total MW	**391.5**	**-**	**403.7**	**-**
Weighted Average Price	**-**	**377.00**	**-**	**358.80**

[36] See Chapter 3 for an in-depth explanation of the DR auction process.

Relevance

The DR Auction is part of the IESO's transitional program to migrate the procurement of demand response from previous multi-year, contracted programs into a more competitive, near-term market mechanism within the IESO-administered markets. Instituting the DR Auction is viewed by the IESO as a foundational step to introduce a market-based mechanism to procure capacity, with the aim to allow for the entry of new, cost-effective demand response providers, enable system flexibility, and evolve the demand response sector to eventually compete with conventional forms of capacity such as supply or import resources. The DR Auction is also one of the key instruments the IESO is using to work towards the policy goal set forth in the 2013 Long Term Energy Plan of reducing peak demand by 10% in 2025.

Commentary

As Ontario has 10 electrical zones with varying supply and demand conditions, the auction took place on a zonal level by creating limits for the amount of DR procured in each zone. Zones with more generation than load would require less DR, while zones with more load than generation can have DR playing a greater role in matching supply and demand. For these reasons, Toronto was the zone with the greatest capacity obligation, holding 40.7% and 39.4% of the total capacity obligation in the summer and winter commitment periods, respectively. There was no cleared capacity in Bruce because no participant submitted offers into the auction. See section 3.2 of Chapter 4 for an in-depth discussion of the DR auction.

2 *Demand*

This section discusses Ontario energy demand for the Current Reporting Period relative to previous years.

Figure 2-20: Monthly Ontario Energy Demand
May 2011 – April 2016
(TWh)

Description:

Figure 2-20 presents energy consumption by all Ontario consumers in each month in the past 5 years. The figure represents Ontario demand, which includes demand satisfied by behind-the-meter (embedded) generators.

associated with a megawatt-hour of export demand. As a result, exporters benefit disproportionately when disbursements are based on demand; such a methodology does not result in what the Panel considers to be a fair allocation.[75]

Had disbursements been allocated in line with the Panel's view on fairness, Ontario transmission customers would have received disbursements totalling $405 million while exporters would have received $7 million. Under such an allocation, Ontario transmission customers would have received an additional $51 million in disbursements that was actually paid to exporters.

Given the IESO's revised TR Clearing Account policies aimed at balancing congestion rents and TR payments, the Panel expects all future auction revenues to be disbursed to transmission customers. Since 2010, auction revenues have increased each year, eclipsing $100 million per year in 2015 and 2016. Left unremedied, the disbursement allocation methodology will continue to be a significant issue going forward.

Recommendation 4-1:

A. ***The IESO should revise the manner in which it allocates disbursements from the Transmission Rights Clearing Account such that disbursements are proportionate to transmission service charges paid over the relevant accrual period.***
B. ***The IESO should not disburse any further funds from the Transmission Rights Clearing Account until such time that Recommendation 4-1(A) has been addressed.***

3.2 *Assessment of the IESO's Demand Response Auction*

Since 2004, the Government of Ontario has been mandating the development of electricity conservation programs. The primary aim of these programs is to alleviate the need to build new generation facilities by reducing demand during peak periods.[76] Demand Response (DR) programs, which incent consumers to reduce consumption during periods of high prices, high demand or tight supply, have been a large part of that conservation effort.

[75] The transmission charges applicable to Ontario transmission customers are broken down into three separate OEB approved rates: Network Service Charge, Line Connection Service Charge and Transformation Connection Service Charge. Together these rates currently total $8.97/MWh. Exporters are subject to the Export Transmission Service (ETS) charge, which is currently set at $1.85/MWh. Both the rates charged to Ontario transmission customers and exporters are set annually and have varied over time, though the rates applicable to Ontario transmission customers have always been higher than the ETS charge.

[76] The Ministry of Energy's *Conservation First: A Renewed Vision for Energy Conservation in Ontario* report states that, "Ontario's vision is to invest in conservation first, before new generation, where cost-effective." The report is available at: http://www.energy.gov.on.ca/en/files/2013/07/conservation-first-en.pdf

The IESO is responsible for achieving the conservation related policy goals set forth by the Ministry of Energy. Prior to 2015, bilateral contracting was the primary means of procuring the necessary DR resources to meet policy objectives; in 2015, the IESO developed the DR auction. The DR auction introduced a competitive, flexible and transparent process for procuring DR resources, where formerly there was none.

The DR auction occurs once annually and procures DR resources for a period of one year. As part of the auction process eligible resources submit the quantity of DR capacity they are willing to provide, and the price at which they are willing to provide it; the IESO uses those offers to build a supply curve. The DR auction clearing price is set where the supply curve intersects the administratively determined demand curve; all resources selected in the DR auction receive the clearing price.[77] To be paid, resources procured through the DR auction must be made available to reduce consumption during specified periods, and must actually reduce consumption when certain activation criteria are met. For this service, resources procured in the 2016 and 2017 DR auctions will be paid up to a total of $73 million; these payments are recovered from Ontario consumers through an uplift charge.[78]

Two types of resources are permitted to participate in the DR auction: dispatchable loads and hourly demand response (HDR) resources. Dispatchable loads already participate in the energy market, changing their consumption in response to five-minute price signals; participating in the DR auction should not materially change the behaviour of these resources. For that reason, the following sections focus on HDR resources, unless otherwise stated. HDR resources are not willing or able to respond to five-minute price signals, and would not participate in the energy market absent some incentive, such as the payments received through the DR auction. To date, approximately 72% of all DR procured through the DR auction has been from HDR resources.

[77] Given the differences in supply and demand in different areas of the province, the IESO limits the amount of DR procured in each zone. If the limit is reached in a given zone, the clearing price in that zone may differ from the others.
[78] While auction payments are technically recovered from Ontario consumers via uplift, the uplift is allocated in the exact same manner as the Global Adjustment. In other words, a consumer's share of this uplift is based on whether they are Class A or Class B customers: Class A customers are charged based on their share of consumption during the five coincident peak demand hours during a year, Class B customers based on their volumetric consumption on all days. Exporters do not pay this uplift.

The IESO has stated that the DR auction is part of a suite of programs and incentives that will help meet the Ministry of Energy's conservation related policy goals.[79] However, for the reasons explained in this section, it is unlikely that the current DR program will actually contribute to conservation or demand reduction. Briefly, this is because the rules associated with the DR auction establish thresholds for activation which have not been realized to date and are unlikely to be realized in the future.

3.2.1 Meeting the Ministry of Energy's Policy Goal

Having said that, it is worth noting that the IESO views the DR auction as an initial step towards the evolution of capacity procurement in the province; one in which all generating and DR capacity is procured through an integrated auction.[80] The Panel supports this longer-term objective.

In 2013, the Ministry of Energy issued its most recent conservation related policy goal: use DR to meet 10% of peak demand by 2025 (approximately 2,400 MW under then forecasted conditions).[81] The IESO views the DR auction as a means of achieving the Ministry's policy goal:

> *Creating a DR auction will support the province's objective for DR to meet 10 per cent of Ontario's peak demand by 2025 and encourage new competitive DR resources to help meet that goal for Ontario's electricity system.*[82] – IESO

In order for the IESO's suite of DR programs and incentives to achieve peak demand reductions, DR not only needs to be available during periods of peak demand, but must also be activated during those periods. As such, it is important to understand the difference between the procurement of DR capacity (i.e. DR availability), and achieving peak demand reductions (i.e.

[79] See the IESO's *Demand Response Stakeholder Engagement Plan,* available at: http://www.ieso.ca/-/media/files/ieso/document-library/engage/dra/20140911-dr-auction_se-plan_draft.pdf?la=en
[80] For more information on the IESO's capacity auction development plans see slides 7 and 8 of its *Developing a Market Renewal Workplan* presentation, available at: http://www.ieso.ca/-/media/files/ieso/document-library/engage/me/me-20160419-developing-a-workplan.pdf?la=en
[81] For more information on the Ministry of Energy's policy goal see pages 20-27 of the *2013 Long Term Energy Plan* report, available at: http://www.energy.gov.on.ca/en/files/2014/10/LTEP_2013_English_WEB.pdf
[82] See the IESO's *Demand Response Stakeholder Engagement Plan,* available at: http://www.ieso.ca/-/media/files/ieso/document-library/engage/dra/20140911-dr-auction_se-plan_draft.pdf?la=en

DR activations). A program that procures DR capacity, but does not result in DR activations during peak demand, will not help achieve the Ministry of Energy's policy goal.

As currently designed, DR procured through the IESO's DR auction is unlikely to be activated during periods of peak demand. To understand why that is, it is necessary to understand both the availability obligation placed on DR resources and the criteria under which they are activated.

Availability Obligation

DR resources procured through the DR auction are required to participate in the energy market for certain pre-determined commitment periods and availability windows. The availability window applies to business days only: 12 PM to 9 PM from May to October (Summer Commitment Period) and 4 PM to 9 PM from November to April (Winter Commitment Period).

During the availability windows DR resources must enter bids into the energy market at prices between $100/MWh and $2,000/MWh. These bids represent the price at which the resource is willing to be activated for DR. The bids must be entered into the market before the IESO's day-ahead process starts, and remain in the market until the IESO determines the resource will not be activated, or until an activation is completed.

Activation Criteria

In order for a DR resource to be activated during the applicable availability window, it must receive both a standby notice and an activation notice from the IESO.

First, a DR resource will receive a standby notice at or before 7 AM if the pre-dispatch nodal price at its location is above its bid price for four consecutive hours within the availability window. Second, if the resource receives a standby notice, it may next receive an activation notice 2.5 hours prior to activation, so long as the price remains above its bid price for four consecutive hours within the availability window. If a DR resource receives an activation notice it must reduce its consumption for a period of four hours, beginning with the first hour included in the activation notice.

Consider the following example: a DR resource is procured for the Winter Commitment Period; to fulfill its availability obligation it bids $1,999/MWh into the energy market during all hours of the availability window. For simplicity, assume that any activation will start at 4 PM and conclude at 8 PM.[83]

Under these conditions the DR resource will receive a standby notice if, during any of the hours before 7 AM, the pre-dispatch nodal prices for the 4 PM to 8 PM activation period exceed the resource's $1,999/MWh bid. To then receive an activation notice, the same conditions must persist at 1:30 PM, in which case the resource must reduce its consumption for the 4 PM to 8 PM activation period.

Prospect of Being Activated

Given the activation criteria described above, the likelihood of an activation is remote. This is borne out by events since the Current Reporting Period; since the first commitment period started in May 2016, no HDR resource has been activated.

Under the program rules DR resources can bid into the energy market at any price between $100/MWh and $2,000/MWh; the higher the bid price, the lower the likelihood of being activated. Table 4-1 contains the prices used to date by HDR resources when submitting their bids to the energy market.

Table 4-1: HDR Resources' Bids into the Energy Market
May 2016 – December 2016

Observed Bid Prices	HDR Capacity Bid at Observed Price
$1,999/MWh	82%
$500/MWh	18%

Since the start of the first commitment period 82% of all DR capacity has been bid into the energy market at the program's maximum allowable price. While the Panel supports DR resources being able to bid into the energy market at any price, bidding at the maximum allowable price, in conjunction with the current activation criteria, means that HDR resources will not be activated. Indeed, the Panel's analysis indicates that any bid price over $220/MWh would not have been activated during the period.

[83] During the Winter Commitment Period, a DR resource may also have an activation period from 5 PM to 9 PM. During the Summer Commitment Period an activation period may span any four consecutive hours between noon and 9 PM.

Given Ontario's current surplus supply conditions and the prices that persisted over the period, it is not surprising that there were no activations.

That said the province has not always been flush with surplus supply. In 2005 and 2006 all-time demand records were being set in Ontario, and in the winter of 2014 the "polar vortex" weather event increased demand and constrained supply. To get a sense of the likelihood of an activation given the current activation criteria, the Panel applied the same criteria to all hours dating back to the high demand conditions experienced in 2005. Table 4-2 displays the number of HDR activations that would have occurred at various bid prices since 2005.

Table 4-2: Hypothetical HDR Activations by Bid Price 2005 – 2016 (Number of Activations)

Energy Bid Price ($/MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
100 - 200	552	152	199	188	1	26	18	16	4	168	66	88
200 - 300	65	16	7	4	-	3	4	-	5	51	-	33
300 - 400	27	9	-	4	-	-	-	-	-	6	-	-
400 - 500	27	9	-	-	-	-	-	-	-	-	-	-
500 - 600	25	3	-	-	-	-	-	-	-	-	-	-
600 - 700	15	1	-	-	-	-	-	-	-	-	-	-
700 - 800	8	1	-	-	-	-	-	-	-	-	-	-
800 - 900	4	-	-	-	-	-	-	-	-	-	-	-
900 - 1,000	1	-	-	-	-	-	-	-	-	-	-	-
1,000+	-	-	-	-	-	-	-	-	-	-	-	-

Since 2005, no bid price above $1,000/MWh would have been activated, yet most HDR resources bid at twice that price. Any bid price over $400/MWh would not have been activated since 2006.[84]

Even under the most aggressive of demand projections, peak demand is not expected to return to record 2005 and 2006 levels until 2029.[85] Ontario is also in a better supply situation than it was during those years, having added thousands of megawatts of capacity to the grid.[86]

[84] Going forward, new HDR resources may emerge at different locations on the grid; their likelihood of activation may differ.
[85] See the IESO's most recent *Ontario Planning Outlook*, available at: http://www.ieso.ca/Documents/OPO/Ontario-Planning-Outlook-September2016.pdf
[86] See *The Need for Capacity* section below for a summary of Ontario's current supply and demand conditions.

The Panel is mindful that reducing consumption during periods of peak demand is a means to an end, and should not be a goal unto itself. A DR resource may wish to consume during periods of high demand, but may be incented to abstain in order to alleviate the need to build additional supply. In this way, DR programs incur short-term costs (i.e. curtailing otherwise efficient energy consumption) in order to avoid long-term costs (i.e. reducing the need for additional peak generation capacity). As long as the avoided long-term costs exceed the incurred short-term costs, reducing peak demand can be efficient.

Ontario is currently flush with supply, and will continue to be for the foreseeable future (see *The Need for Capacity* section below). Even with considerable demand growth, there is little need to build new capacity. Consequently, consumption during peak periods results in no additional long-term capacity costs, meaning demand reductions during these periods are unnecessary and likely inefficient. It follows that payments to procure DR, such as those provided by the DR auction, are also unnecessary and inefficient.

3.2.2 Meeting the IESO's Capacity Objective

As mentioned in the previous section, the IESO's DR auction is unlikely to provide energy through DR activations given the current activation criteria.

The notion that the DR auction is procuring capacity only is consistent with the program's availability obligations, as well as the manner in which DR resources are compensated. Specifically, DR resources are paid to be available for activation, not to be activated; there are no minimum requirements on the number of times a resource must be activated. In furtherance of this idea, the IESO plans to integrate the DR auction and its participants into the broader capacity auction currently being developed through the IESO's Market Renewal initiative.[87] In the sections that follow, the Panel assesses the appropriateness of the DR auction as a means to procure capacity.

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[87] For more information on the IESO's capacity auction development plans see slides 7 and 8 of its *Developing a Market Renewal Workplan* presentation, available at: http://www.ieso.ca/-/media/files/ieso/document-library/engage/me/me-20160419-developing-a-workplan.pdf?la=en

Availability Obligation and Activation Criteria

Unlike meeting the Ministry of Energy's policy goal of using DR to reduce peak demand, procuring capacity does not necessarily come with the expectation that it will be utilised regularly or predictably. The IESO must procure enough capacity to ensure that Ontario's electricity needs are met, plus some additional capacity to ensure reliability. On that basis, one would expect there to be a portion of capacity that is rarely if ever used. Specifically, capacity resources with high bids in the energy market, such as those procured to date through the DR auction, are the last to be activated and are likely only needed on rare occasions. For DR capacity to be of use, the activation criteria needs to result in consumption reductions on those infrequent occasions when those resources are needed.

As noted earlier, HDR resources bidding at the maximum allowable energy market price (82% of all HDR resources to date) would not have been activated from 2005 onwards; resources bid above $400/MWh would not have been activated since 2006. There have been occasions since 2005, including during the very tight supply conditions experienced during the winter of 2014, when DR activations could have been beneficial.[88] To that end, the Panel encourages the IESO to assess whether changes to the current availability obligations and activation criteria should be made in order to facilitate activations when needed.

Technology-Specific Procurement

In terms of satisfying the need for capacity, capacity from DR is no different than capacity from other resources, such as gas-fired generators. Given the substitutability of capacity from different technologies, the procurement process should be technology neutral, not favouring one technology over another. Technological neutrality allows the procurement mechanism to select the lowest cost capacity, no matter the resource type. In order for the procurement mechanism to be technologically neutral it must permit all resources to compete against one another to supply capacity, and place identical obligations on all resources procured. The need for technology-neutral procurement was recently supported by the Minister of Energy, Glenn Thibeault:

[88] The Panel finds it instructive that, over the same period, there were numerous other DR programs with differing activation criteria that resulted in activations, including activations under the program the DR auction is effectively replacing.

Upon taking this office, I was interested to learn that our previous procurements were essentially segmented into "technology-specific" allotments. In this day and age, with the level of innovation, pace of technological change – as well as the clear benefit to ratepayers from competitively procured resources; it is essential that we begin moving towards more "technology-agnostic" procurements.

Too often we have sought to impose strict requirements on the system operator. Rather, as we seek to undertake future procurements – we should be focused on outcomes, rather than contracting with specific technologies. Moving to become technology-agnostic will provide new opportunities for innovation and modernization. We must unleash the electricity sector and our system operator to find the appropriate mix to fulfil a capacity auction would ensure that ratepayers receive the best prices possible.[89]

***

Allocating the precise mix of technology types has largely been arbitrary and led to suboptimal siting, uncompetitive prices and heightened community concerns.[90]

The DR policy goal set by the Ministry of Energy in 2013 is technology specific, as was the IESO's corresponding procurement. Currently, DR is the only capacity procured through an auction process. By limiting competitive procurement to one resource type, the IESO is limiting its ability to procure capacity at least cost. Fortunately, the IESO is considering the introduction of a technology-neutral capacity market, allowing for DR resources to compete against other technologies to provide capacity at least cost in the future.

The Need for Capacity

The quantity of DR capacity procured through the DR auction is determined by the intersection of the participant-offered supply curve and the IESO determined demand curve. The demand curve sets the bounds for how much DR capacity will be procured at different prices, including the maximum quantity at the auction's lowest price, and the minimum quantity at its highest price.

[89] Speech delivered by Glenn Thibeault (Minister of Energy) to the Empire Club of Canada on November 28, 2016.
[90] Comments made by Glenn Thibeault following his speech to the Economic Club of Canada on February 24, 2017, as reported in the Globe and Mail's article: *Ontario Liberals Eye Electricity Market Overhaul to Lower Rates*, available at: http://www.theglobeandmail.com/news/ontario-liberals-eye-electricity-market-overhaul-to-lower-rates/article34128778/

The IESO sets the position of the demand curve (i.e. how much DR will be bought at different prices) by setting a target quantity and price for procuring DR capacity. Recall that prior to the auction, DR was procured through bilateral contracting; those legacy contracts expire at different times, the last of these expires in 2018.[91] For the first DR auction, the IESO set the target quantity equal to the capacity that was expiring under those legacy contracts.[92] The IESO set the target price equal to the agreed upon price in those expiring contracts. In effect, the quantity of DR procured for 2016, and the price at which it was procured, was largely determined by market conditions that prevailed when those legacy contracts were signed (upwards of five years prior in some cases).[93] The IESO plans to increase DR capacity targets in future auctions by 7% per year, with additional increases as more legacy DR contracts expire.[94] In the Panel's view, the procurement of capacity for future periods should not be based on administratively determined growth rates or the volume of contract expirations, but rather on a reasonable expectation of capacity needs during the commitment period.

Regardless of the procurement mechanism, the decision on how much capacity to procure, if any, should be directly tied to the need for capacity. The IESO recently assessed the long-term need for capacity in Ontario, noting the province's strong capacity position in its *Ontario Power Outlook* report, "Ontario will have sufficient resources to meet demand requirements generally over the next decade across all [demand] outlooks".[95] This assessment is consistent with the IESO's most recent *18-month Outlook*.[96] Indeed, even without the expected capacity contributions of resources procured through the DR auction,[97] Ontario has sufficient capacity to

[91] See slide 4 of the IESO's September 2016 presentation: *Update on Target Capacity and Commitment Period*, available at: http://www.ieso.ca/sector-participants/engagement-initiatives/working-groups/-/media/files/ieso/document-library/working-group/demand-response/DRWG-20160930-Update-on-Target-Capacity-and-Commitment-Period.pdf
[92] See page 3 of the IESO's approved Market Rule Amendment Proposal (MR-00416-R01), available at: http://ieso.ca/Documents/Amend/mr2015/MR_00416_R01_Amendment_Proposal%20v5.0.pdf
[93] See slide 10 of the Ontario Power Authority's April 2014 presentation: *Demand Response Programs in Ontario*, available at: http://www.ieso.ca/sector-participants/engagement-initiatives/working-groups/-/media/files/ieso/document-library/working-group/demand-response/drwg-20140403-DRWG-OPA-Presentation.pdf
[94] See slide 3 of the IESO's September 2016 presentation: *Update on Target Capacity and Commitment Period*, available at: http://www.ieso.ca/sector-participants/engagement-initiatives/working-groups/-/media/files/ieso/document-library/working-group/demand-response/DRWG-20160930-Update-on-Target-Capacity-and-Commitment-Period.pdf
[95] See page 11 of the IESO's *Ontario Power Outlook*, available at: http://www.ieso.ca/Documents/OPO/Ontario-Planning-Outlook-September2016.pdf
[96] See page ii of the IESO's *18-Month Outlook,* available at: http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/18-month-outlook/18monthoutlook_2016sep.pdf
[97] The IESO's target procurement capacity for the DR auction is 648 MW in 2018, growing to 1,246 MW in 2025. For more information see the IESO's September 2016 presentation: *Update on Target Capacity and Commitment Period*, available at:

meet its needs for many years. Based on the IESO's most aggressive demand outlook (plus a reserve margin), and without any contribution from the DR auction, Ontario has sufficient capacity to meet its capacity needs until 2021. Under the most conservative demand outlook, Ontario has sufficient capacity until 2025.

Accordingly, the IESO is procuring capacity through the DR auction at a time when capacity is not needed. This procurement comes at a significant cost: resources procured through the 2016 and 2017 DR auctions will be paid upwards of $73 million in total. Under the most aggressive of assumptions, additional capacity is not needed until 2021. Fortuitously, the technology-neutral capacity auction in development is expected to have its first capacity auction in 2020 to procure capacity for future years.[98] Not only is the technology-neutral capacity auction a more cost effective way to procure capacity, but the timing of its implementation aligns far better with Ontario's capacity needs. [99]

In this regard it is noteworthy that various other capacity procurement projects have been cancelled or scaled back in recent years, including round two of the Large Renewal Procurement process,[100] and rounds five and six of the Feed-In Tariff program.[101]

Recommendation 4-2:

The IESO should reassess the value provided by the capacity procured through its Demand Response auction in light of Ontario's surplus capacity conditions, as well as the stated preference of the government and the IESO (through its Market Renewal initiative) for technology-neutral procurement at least cost.

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http://www.ieso.ca/sector-participants/engagement-initiatives/working-groups/-/media/files/ieso/document-library/working-group/demand-response/DRWG-20160930-Update-on-Target-Capacity-and-Commitment-Period.pdf

98 See slide 44 of the Brattle Group's December 2016 presentation: *IESO Market Renewal Benefits Case: Preliminary Benefits Case Findings*, available at: http://ieso.ca/-/media/files/ieso/document-library/engage/me/me-20161219-preliminary-benefits.pdf?la=en

99 As part of its reasoning for implementing the DR auction, the IESO stated the auction will, "Provide a stable transition [from bilateral DR contracts] that offers a learning opportunity for DR providers to be able to successfully compete in a full capacity auction." While that may be true, that learning opportunity comes at a cost that will well exceed $100 million, all the while providing little benefit. For more information on the IESO's justification for the DR auction, see its Market Rule Amendment Submission (MR-416-Q00), available at: http://www.ieso.ca/Documents/Amend/mr2015/MR-00416-Q00.pdf

100 See the Minister of Energy's Letter to the IESO, dated September 27, 2016, available at: http://www.ieso.ca/-/media/files/ieso/document-library/ministerial-directives/2016/directive-lrpii-efwsop-20160927.pdf?la=en

101 See the Minister of Energy's Letter to the IESO, dated December 16, 2016, available at: http://www.ieso.ca/-/media/files/ieso/document-library/ministerial-directives/2016/directive-nug-20161216.pdf?la=en

TAB 7

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

Ontario

Market Surveillance Panel

Monitoring Report on the IESO-Administered Electricity Markets

for the period from
May 2016 – October 2016

February 2018

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2 *IESO Responses to Panel Recommendations in Last Monitoring Report*

Below are the recommendations made in the Panel's May 2017 Monitoring Report, and the IESO's responses to them.[9]

Recommendation	IESO Response
Recommendation 3-1 *The IESO should take steps to ensure that dispatchable loads are only compensated for the amount of operating reserve they were capable of providing in real-time. More fundamentally, the IESO should explore options for ensuring unavailable OR is not scheduled in the first instance.*	The IESO agrees that market participants should not be compensated for services that they are unable to provide. The Market Rules require all market participants, including dispatchable loads, to maintain accurate dispatch data and respond to IESO dispatch instructions for both energy and operating reserve. The IESO will assess what remedies are available to respond to the Panel's recommendation in 2017. These remedies could include but are not limited to changes to market design through Market Rules or investigations of non-compliance.
Recommendation 3-2 *The IESO should revise the methodology used to set the intertie failure charge to include the congestion rents that an intertie trader avoids when it fails a scheduled transaction for reasons within its control.*	The IESO agrees with the Panel's recommendation on intertie transaction failures; an intertie trader should not benefit by avoiding congestion rents when failing intertie transactions for reasons within its own control. Market Rules are in place that allow for the recovery of congestion rents that have been avoided, or Transmission Rights payments, when the intertie trader fails its transactions for illegitimate reasons. The IESO will consider the structure of intertie failure charges in 2017 and determine an appropriate avenue to address the issue identified by the Panel.

[9] See the May 30, 2017 letter from Bruce Campbell, then President and CEO of the IESO, to Rosemarie Leclair, Chair and CEO of the Ontario Energy Board, available at: https://www.oeb.ca/sites/default/files/IESO-Reply-to-OEB-MSP-Report-20170530.pdf

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Recommendation 4-1

a) *The IESO should revise the manner in which it allocates disbursements from the Transmission Rights Clearing Account such that disbursements are proportionate to transmission service charges paid over the relevant accrual period.*
b) *The IESO should not disburse any further funds from the Transmission Rights Clearing Account until such time that Recommendation 4-1(A) has been addressed.*

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The current disbursement methodology of the Transmission Rights Clearing Account is to allocate disbursements to both internal and external loads based upon their share of demand. In 2017 the IESO will initiate a review of the disbursement allocation methodology to ensure it is both consistent with the intent and purpose of the Transmission Rights Clearing Account, and is aligned with current market and system needs. The outcome of the review, which will be completed and communicated to the Panel by the end of 2017, could also inform the Transmission Rights discussions that will take place as part of the IESO's Market Renewal Program. Given that the allocation method is Market-Rule based, the outcome of the review will also inform whether changes to the Market Rule are required.

Meanwhile, until the review of the disbursement allocation methodology is completed, the IESO will continue with the semi-annual disbursements, as directed by the IESO Board and as detailed in Market Manual 5.5: Physical Markets Settlement Statements.

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Recommendation 4-2

The IESO should reassess the value provided by the capacity procured through its Demand Response auction in light of Ontario’s surplus capacity conditions, as well as the stated preference of the government and the IESO (through its Market Renewal initiative) for technology-neutral procurement at least cost.

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The IESO was assigned responsibility for developing Demand Response (DR) in Ontario in 2013 with a mandate to develop DR to meet system and policy objectives in the short and longer term. Since that time, the IESO has developed a comprehensive work plan to ensure contracted resources are integrated cost effectively into the market. As a result of these initiatives, the annual cost of maintaining DR has dropped by almost 30%, while participation has increased significantly and new innovative approaches are continuing to emerge.

In the short term, DR is contributing to the reliability of the Ontario grid as an integrated resource that is dispatched when it is economic relative to other resources. Over the longer term, the IESO agrees with the MSP that a technology-neutral capacity auction is a more cost effective way to procure capacity. The IESO has launched a stakeholder engagement to design such a mechanism as part of the Market Renewal Program. The learnings from the DR auction will help inform the design of a future incremental capacity auction and demonstrate how such a mechanism could work in Ontario.

The IESO is also working together with stakeholders through the DR Working Group (DRWG). The IESO and the DRWG are committed to continuously improving the efficiency of the DR auction and working together to assess priorities for 2017. The DRWG work plan includes a number of projects to improve the efficiency of the DR auction, including a review of how DR is activated in the market.

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3 *Panel Commentary on IESO Responses*

Recommendations 3-1 and 3-2

With respect to recommendations 3-1 and 3-2, the IESO agreed that action should be taken to address the inappropriate outcomes identified by the Panel, and committed to assessing potential solutions in 2017. In both cases, the Panel believes that the optimal solution would be one that prevents these inappropriate outcomes from arising in the first instance, rather than relying on after-the-fact payment recoveries or compliance actions.

Recommendation 4-1

The IESO committed to reviewing the current disbursement methodology for the Transmission Rights Clearing Account (TR Clearing Account) in 2017, to ensure that it is consistent with the intent and purpose of the TR Clearing Account, and aligned with current market and system needs.

With respect to the Panel's recommendation that the IESO stop disbursing funds from the TR Clearing Account until such time as revisions are made to the disbursement methodology, the IESO indicated that it would proceed with semi-annual disbursements as directed by the IESO Board of Directors and as detailed in the relevant Market Manual. The IESO has since made an additional disbursement of $76 million from the TR Clearing Account (in July 2017) using the existing methodology.[10] As a result, $11.3 million has been paid to exporters, $9 million of which ought in the Panel's view to have been for the benefit of Ontario ratepayers

Recommendation 4-2

The IESO was not directly responsive to the Panel's recommendation, as it has not indicated an intention to reassess the value provided by the capacity procured through its Demand Response (DR) auction. In the Panel's view, the IESO is procuring capacity through the DR auction at a time when additional capacity is not needed. Upwards of $73 million has been paid to demand response resources through the 2016 and 2017 auctions.

[10] See the IESO's June 1, 2017 News Release, available at: http://www.ieso.ca/en/sector-participants/ieso-news/2017/06/transmission-rights-clearing-account-disbursement.

While the IESO's response did not address the Panel's primary concern, it is consulting stakeholders about potential changes to the DR activation criteria. The changes being considered could increase the frequency with which DR resources are activated, and better align activations with system needs.[11]

[11] For more information, see the IESO's July 18, 2017 presentation entitled *Improved Utilization of DR*, available at: http://www.ieso.ca/en/sector-participants/engagement-initiatives/working-groups/demand-response-working-group

TAB 8

Demand Response Discussion Paper

Utilization Payments

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December 18, 2017

Disclaimer

This report was prepared by Navigant for the Independent Electric System Operator.

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1. INTRODUCTION

This paper was drafted to provide context and research on utilization payments and inform a dialogue on their possible merits to drive additional, economically efficient, curtailment of loads to meet a variety of electricity system needs. This discussion paper includes a review of practices in other jurisdictions, arguments for and against providing a utilization payment to demand response (DR) resources, a qualitative assessment of the potential impact of utilization payments on the dispatch frequency of DR resources in Ontario, and a qualitative assessment of the effect of any changes in payment structure on the wider market. ***This paper focuses solely on economic (i.e. energy) and reliability (i.e. capacity) DR that is linked to an organized wholesale power market and the question of economic efficiency relative to the status quo in Ontario.***

There is disagreement about the efficiency and fairness of allowing a single DR resource to capture both energy (utilization) and capacity (availability) payment streams.[1] At the broadest level, proponents of both payments for load resources argue that calling on a DR resource to curtail provides incremental value to the power system, and these load reductions should be compensated through utilization payments much like a generation resource participating in both capacity and energy markets. Opponents argue that the availability payment adequately compensates a DR resource for providing capacity and that utilization payments are a form of double payment as the DR provider receives a benefit in terms of its avoided cost of electricity when it is utilized. This paper will discuss these and other arguments for and against both availability and utilization payments.

DR has been part of the Ontario electricity system since the early 2000s. Dispatchable load resources were active in the IESO-administered market since the market open in 2002. In 2007, the IESO (former OPA) recognized that there was capacity value from demand-side resources and started the DR3 program. DR resources were procured through multi-year standard offer contracts in the DR3 program. The DR3 program included availability payments and utilization payments. In December 2015, the DR programs were integrated into the IESO-administered wholesale power market with the advent of the DR auction.

The DR auction procures DR resources as reliability/capacity resources. Participants offer into two seasonal DR auctions. Participants who clear the auction are required to be available to the IESO to meet peak demand. As part of this, they have a requirement to bid into the real-time energy market between a price floor of $100 and price ceiling of $1999.99 for each business day during the season. A DR resource is dispatched through the IESO's security constrained dispatch algorithm and is curtailed when economic in the seasonal activation window. Availability payments are made to DR resources that clear in the DR auction regardless of how often they are dispatched to curtail. DR resources participating in the DR auction do not receive an additional utilization payment when they are dispatched.

For some wholesale customers, the opportunity cost of curtailing load in any individual hour is higher than the IESO ceiling price. They participate in the market mainly to receive capacity payments. The main impact of this dynamic is that DR resources in Ontario tend to bid into the energy market at the ceiling price to minimize their utilization and are seldom called upon to curtail.

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[1] DR also participates in ancillary service markets in a number of jurisdictions, however, the use of utilization payments in these markets is widely accepted and outside the scope of this report.

It is important to note that Ontario is different from many U.S. jurisdictions in that many of the DR resources are wholesale market participants or large customers that are exposed to real-time electricity prices as opposed to retail prices. This means that Ontario DR customers avoid the entire real-time electricity price when curtailing and are exposed to high price spikes. When DR providers are only exposed to retail rates as they are in many U.S. jurisdictions, they are unlikely to have the same avoided cost benefit when curtailing during spikes in prices.

2. BACKGROUND AND DEFINITIONS

This section outlines four levels of considerations that should be reflected upon when discussing DR program or market design. The first is the type of DR resource sought. The second is the payment structure used to compensate the DR resource. The third is the mechanism to establish the payment level for each of the payment structures. The fourth is the evaluation or decision criteria used to assess the tradeoffs between different options.

2.1 Types of DR

DR resources are generally categorized into three different classes.

- ***Economic / Energy***: Economic DR is a commitment to reduce consumption when productive or convenient. Economic DR resources are typically dispatched based on an hourly bid price. These resources do not receive availability payments in the jurisdictions reviewed.

- ***Reliability / Capacity***: Reliability DR is a firm commitment to reduce consumption during times of scarcity or system contingencies. Reliability DR resources are typically dispatched manually. These resources receive an availability payment in exchange for being available to curtail. Ontario is unique, in the sense that reliability DR resources are dispatched through the IESO's dispatch algorithm.

- ***Ancillary services***: Ancillary services DR is the provision, by load, of specialty services that are essential to the secure operation of the system for example operating reserve and frequency regulation.

In many jurisdictions resources can participate in more than one of these DR program. For example, in PJM DR resources can participate in both the economic and reliability DR programs and in Ontario dispatchable loads which are a type of economic / energy can also participate in the 10-minute and 30-minute operating reserve markets.

2.2 Payment Structures

There are two basic payment structures for DR resources. DR resources may be provided with an availability payment, a utilization payment, or a combination of both.

- ***Availability payment***: A fixed daily, monthly, or annual payment made to DR resources in exchange for the guarantee that they will be ready to curtail their load when called upon. Typically, this payment compensates the service provider for the fixed costs associated with providing the service. In most jurisdictions, including Ontario, availability payments are used for reliability/capacity DR.

- ***Utilization payment***: A payment made to DR resources when they are called upon to modify their load. Payments are typically based on the actual level of curtailment. Utilization payments that are based on a market price are often referred to as energy payments.[2] Utilization payments

[2] Note that in U.S. jurisdictions, utilization payments are almost always tied to the energy market and it is broadly accepted to refer to them as energy payments. This framework is driven by FERC Order No. 745.

are generally intended to compensate DR resources for the variable (marginal) costs associated with providing the service. In most regions, utilization payments are used for DR that provide economic/energy DR.

2.3 Payment Levels

Payment levels for both availability and utilization payments can be set in several ways. Utilization payments are typically set administratively, through a pay-as-bid process, or tied to wholesale energy prices.

- ***Administrative Payments***: The level of payment is determined by the program or market administrator and incorporated into the contract with a DR resource or DR program rules. This type of utilization payment is usually not provided to DR resources participating in the power markets. For example, in the previous DR3 program in Ontario, resources were paid an administrative payment ($200/MWh) when they were activated.

- ***Pay-As-Bid:*** The level of payment is determined by each individual DR resource's bid or offer price. In some cases, DR resources include a pay-as-bid price in their bids which if activated they are paid. This is a model used in some jurisdictions where resources receive utilization payments for reliability DR activation. It can also be used as payment structure for resources who are activated through a DR program rather than through participation in power markets.

- ***Wholesale Energy Price:*** The level of payment is determined by the market clearing price in a wholesale energy market. In 2011, FERC Order No. 745 stipulated that DR resources participating in organized wholesale energy markets should receive a utilization payment equal to the Locational Marginal Price (LMP). The LMP reflects the value of energy at the specific location and time it is delivered. A more detailed description of the FERC Order and associated arguments has been included in Appendix B.

- ***Modified Wholesale Energy Price:*** An alternative to the market clearing price, resources may receive is an adjusted market clearing price, where the market clearing price is modified by some factor. An example of a modified wholesale energy price payment is LMP-G which is the market clearing price minus the retail price or in call terminology the spot price minus the strike price. FERC Commissioner Moeller in his dissenting opinion in Order No. 745 argued that paying LMP results in DR resources being overcompensated by the amount of the retail generation rate and paid more than a generator would in providing energy. He argued for a modified rate of ***LMP minus the retail generation rate***.[3]

2.4 Evaluation Considerations

Compensating DR resources that provide capacity through availability payments is broadly accepted. However, there is significant disagreement on whether DR resources should receive a utilization payment when they are curtailed. Historically, utilization payments have not had a large impact on DR participation

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[3] http://www.bostonpacific.com/back-basics-demand-response-compensation/

levels (i.e. the amount of DR registered or contracted) or activation levels (i.e. how often it is curtailed). However, new technologies such as energy storage and the improving economics of distributed energy resources present an opportunity for additional DR participation and the payment structure for these types of DR resources needs to be considered more thoroughly.

There are many different criteria that can be used to evaluate trade-offs between payment structure and payment level decisions.

- **Economic Efficiency:** The efficiency of a power market is frequently evaluated using three concepts of efficiency.

  Productive efficiency (also called technical efficiency) occurs at a specific point in time if a given level of output is produced with the least amount of inputs. The Ontario electricity market achieves productive efficiency if the least cost resources are dispatched to meet demand.

  Allocative efficiency occurs at a specific point in time if resources are allocated in a way that maximizes the gains from trade or the net benefit attained through their use. This occurs when the social marginal benefit of the last unit produced equals its social marginal cost. In the wholesale market, the social marginal cost would include, for example, the marginal cost to produce the energy plus the marginal cost of emissions. In the Ontario market, allocative efficiency is largely about getting the price right for consumers so that they can make efficient consumption decisions.

  Dynamic efficiency is concerned more with the pace of investment and innovation in a market. It involves efficient technology choice and timely and efficient capacity investment decisions both on the supply side and the demand side of the industry. In the Ontario electricity market, this would include ensuring we have the efficient supply mix, both at the transmission and distribution level given our demand profile, and that consumers are making the right investments in the technologies needed to manage their consumption.[4]

- ***Consumer Benefits*:** Consumers are responsible for most if not all of the costs of the electricity system. Changes to power markets are sometimes evaluated based on the impact the changes will have on the cost to consumers.

  With utilization payments, DR resources would have an incentive to bid values lower than the ceiling price into the energy market as they would receive payment whenever they are activated. This may lead to reduced wholesale energy prices if DR resources are bidding lower than traditional generation. The merit of utilization payments may be evaluated based on their ability to reduce cost to consumers.

- ***Level of Participation or Activation:*** Another consideration that is relevant for DR is the level of participation or the level of activation. The level of participation refers to the amount of DR, typically measured in megawatts, that is registered or contracted. In certain circumstances, the level of participation can be used as a proxy for the level of competition. The level of activation

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[4] Charles River Associates. *How to put Ontario's power market on a faster track to economic efficiency*. October 2016.

refers to the amount of DR that is activated, typically measured in megawatt-hours, over a defined period.

With utilization payments, more DR resources may participate in the market. If more resources are participating in the market the competition is likely to be greater which would like to lower costs. The merit of utilization payments may be evaluated based on their ability to increase the amount of DR participating in the market.

- ***Fairness:*** Another potential consideration is fairness or consistency. In the context of DR, fairness typically refers to how traditional generation resources are compensated relative to demand-side resources.

  DR resources are bidding into the market alongside generation. In the case that they are dispatched rather than generators one could argue that they should be compensated in the same way as the generators.

- ***Materiality:*** A final consideration is materiality. The materiality of the impact of changes to payment structures and payment levels can be a consideration.

  When examining the merit of introducing utilization payments any potential impacts should also be examined by evaluating how significant their impacts. For example, introducing utilization payments may increase participation in the market but this impact may not be significant enough to make any impact on consumer costs.

As a point of consideration, in FERC Order No. 745, the commission ultimately determined that fairness/consistency and materiality outweighed economic efficiency[5].

[5] See Appendix for more detail on FERC 745

3. ECONOMIC EFFICIENCY ARGUMENTS

This section presents the arguments for and against providing utilization payments to DR resources.

3.1 Against Activation Payments in Ontario

3.1.1 Wholesale Price Efficiency

The argument is as follows. Real-time wholesale energy prices are an efficient price signal because they match supply and demand based on bids and offers on a minute-by-minute, hour-by-hour basis.

When price responsive loads are exposed to real-time wholesale electricity prices they assess whether it is more cost effective for them to operate or curtail based on the real-time price signal. During high-price events a customer can choose to curtail and save the cost of electricity. This provides an economically efficient incentive to reduce consumption when prices are higher than a customer is willing to pay.

For example, large industrial customers such as pulp and paper pay for electricity based on the wholesale electricity price. These customers can determine on an on-going basis if it is more economically efficient for them to continue operating and producing pulp and paper given the required input costs of electricity than it would be to stop production leading to loss of production revenues but savings in electricity costs.

Considerations for Ontario: This argument only applies to loads that receive the wholesale energy price. Many large commercial and industrial customers in Ontario are already exposed to wholesale energy prices. These customers are already price responsive. They can determine based on real-time energy prices if it is more cost effective from them to operate or to curtail. These customers would not need an additional payment to be incented to curtail when they are needed by the system. There are some customers in Ontario who are not exposed to the wholesale electricity price. These customers are not exposed to price spikes that occur in the wholesale electricity prices. Since they aren't exposed to the price spikes they are not receiving the signal to curtail when needed by the system. The wholesale price efficiency argument is not relevant in those cases. In Ontario, 58% of the total load is exposed to the market price[6].

3.1.2 Disproportional Benefits

The argument is as follows. Providing a utilization payment compensates a DR resource disproportionally relative to a supply resource, because the DR resource did not incur a cost associated with the production of electricity. Under this argument, a DR resource should be treated as if it had first purchased the power it wishes to resell to the market.

This argument is based on a premise that a megawatt of electricity curtailed (negawatt) is not economically equivalent to producing a megawatt of electricity. This was the argument put forward by a group of economists in support of the Electric Power Supply Association's petition to US Court of Appeals

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[6] http://www.ieso.ca/-/media/files/ieso/document-library/engage/ssm/ssm-20170817-presentation.pdf?la=en

to overturn FERC Order No. 745.[7] This argument was supported by FERC Commissioner Philip D. Moeller, who argued that paying demand response resources full LMP overcompensates those resources because in addition to any incentive payments received, those resources also receive the benefit of not paying the cost of retail energy consumption that they otherwise would have incurred[8].

The underlying factor of this argument is the claim that DR is not a resource in the same way that generation is. A generating resource is providing a product and is paid for that. Opponents of DR utilization payments argue that since DR does not own the power they are not consuming, they should not be paid additionally for not consuming it. Despite this argument, FERC's final 745 ruling[9] was based on the premise that negawatts and megawatts are functionally and economically equivalent.

Considerations for Ontario: This argument is based on a premise that a megawatt of electricity curtailed (negawatt) is not equivalent to a megawatt of electricity. The argument assumes the cost of curtailment (or the value of lost load) for a DR resource is immaterial. Whether the disproportional benefits argument is considered valid in Ontario depends on whether this premise accepted.

3.1.3 Harm to Other Suppliers

The argument is as follows. Utilization payments can lead to greater levels of activation that put downward pressure on wholesale energy prices and negatively impact the profitability of other supply resources.

While initially a benefit to consumers, the argument is that this practice has the potential to harm suppliers in the long term to a point where existing or new generators, required to maintain system reliability, are not able to operate economically. This argument is based on the concept of dynamic efficiency.

The argument is that if more DR resources bid into the market at prices lower than traditional generation they will be dispatched rather than the generation. This is because the more demand response that sees and responds to higher market prices, the greater the competition, and the more downward pressure it places on generator bidding strategies by increasing the risk to a supplier that it will not be dispatched if it bids a price that is too high. This may make it difficult for the generators to recover their costs and ultimately to continue operating. In practice, the impact of providing a utilization payment has not been significant enough to affect generators ability to recover their costs.

Some FERC 745 commenters assert that a power system can function solely and reliably on generating plants and without any reliance on demand response, while the system cannot rely exclusively on demand response because demand response by itself cannot keep the lights on[10].

Considerations for Ontario: To have a material impact on energy prices, utilization payments would have to result in a considerable increase in activation. Also, under the current market structure in Ontario, most generators are under contract or receive regulated rates and hence have a high degree of revenue or price certainty.

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7 https://sites.hks.harvard.edu/fs/whogan/Economists%20amicus%20brief_061312.pdf

8 https://www.cleanenergylawreport.com/energy-regulatory/federal-appeals-court-vacates-ferc-order-no-745-on-demand-response-compensation/

9 https://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf

10 https://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf

3.1.4 Harm to Economy

The argument is as follows. Providing utilization payments may incentivize companies to reduce production to provide demand reductions into the electricity market. Reducing production would in turn reduce the supply of goods in the economy that could increase the cost of these goods.

This argument comes back to the concept of allocative efficiency. It relies on the argument that the wholesale energy price signal is efficient and that introducing a utilization payment will result in inefficient outcomes.

For example, if a company which is producing widgets is incentivized through utilization payments to curtail their load and stop producing widgets fewer widgets will be available to buy. This reduced supply may increase the price of the widgets in the market. In practice, the impact of providing a utilization payment is not expected to be significant enough to cause a material impact on supply of goods (widgets) in the market.

<u>Considerations for Ontario:</u> This argument only valid for supply constrained and non-trade exposed sectors of the economy where prices are set based on local supply and demand. Ontario has a diversified and open economy that responds effectively to changes in supply.

For Activation Payments in Ontario

3.1.5 More DR Activation Reduces Consumer Costs

The argument is as follows. Utilization payments will increase levels of DR participation and activation in lieu of more expensive generation resources.

Utilization payments are a way to incentivize higher levels of DR participation and activation. These DR resources will provide less expensive capacity and energy that in turn will lead to lower consumer costs. This argument is based on the concept of productive efficiency.

For example, if a utilization payment incents DR resources to bid into the energy market at lower prices they will likely be activated more often. If the DR resources are bidding lower than the traditional generation resources the wholesale energy price will be lower. These reduced prices will be passed through to customers in the form of reduced consumer electricity costs.

Large 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 however smaller commercial or residential customers who may have a lower value of lost load are likely to bid into the energy market below the ceiling price. While this will lower energy prices, the impact is not expected to be significant since these resources do not represent a significant amount of the supply required in Ontario.

<u>Considerations for Ontario:</u> To have a material impact on capacity or energy prices, utilization payments would have to result in a considerable increase in levels of participation and activation. Under the current market structure in Ontario, most generators are under contract or receive regulated rates and hence consumer costs are largely fixed. It is also possible that reduced electricity costs could lead to reduced manufacturing costs that may be passed along to consumers as reduced cost of goods.

3.1.6 Disconnect Between Wholesale and Retail Prices

The argument is as follows. There is a disconnect between retail energy prices and wholesale energy prices. Retail prices don't reflect the real-time fluctuations in the cost of electricity and hence are inefficient. DR resources that are exposed to retail prices behave inefficiently because they are not exposed to the true cost of electricity on a short-term basis. Utilization payments are a way of improving the economic efficiency of the retail price during high-price events.

Retail rates paid by some consumers are fixed in advance and do not fluctuate during peak periods. Even when the market price (and the cost) of generating an additional megawatt of electricity during a peak period is relatively high, retail customers (who typically have unlimited access to supply at a fixed rate) do not curtail demand in response to the price signal. For that reason, many economists agree that it may be useful to provide retail consumers with an incentive to avoid using electricity, i.e., to stimulate DR during peak periods.[11] The economically efficient goal should be for resources to reduce their consumption whenever the value of their consumption is lower than the cost of supplying it. It should be noted that many of the existing DR resources in Ontario are exposed to real-time wholesale prices. Emerging DR resources such as aggregated residential or commercial loads are exposed to retail prices as opposed to wholesale prices. As a result, these resources would benefit from a price signal that would incent them to curtail in response to wholesale prices.

Considerations for Ontario: This argument is only valid for customers on retail rates who are not exposed to real-time energy prices. As described previously, many providers of DR in Ontario are already exposed to wholesale rates.

3.1.7 Fairness/Consistency

The argument is as follows. Generation resources receive a utilization payment in the form of an energy payment when they produce electricity. DR resources should be treated fairly/consistently and receive a utilization payment when they curtail electricity.

The argument takes the position that a DR resource and a generation resource providing a megawatt of electricity for the same period are equivalent and should be compensated equivalently. The principle behind this argument is that both demand and supply are "electricity resources". DR has demonstrated that it can serve as a reliable and economic resource for wholesale markets and integrated resource plans. It has demonstrated its ability to mitigate market power that can arise in a generation-only market.

This argument was supported by FERC in the FERC 745 ruling[12]. The Commission argued that when a demand response resource has the capability to balance supply and demand as an alternative to a generation resource, and when dispatching and paying LMP to that demand response resource is shown to be cost-effective as determined by the net benefits, payment by an RTO or ISO of compensation other than the LMP is unjust and unreasonable. When these conditions are met, we find that payment of LMP to these resources will result in just and reasonable rates for ratepayers. FERC indicated that they believe paying demand response resources the LMP will compensate those resources in a manner that reflects the marginal value of the resource to each RTO and ISO.

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[11] https://sites.hks.harvard.edu/fs/whogan/Economists%20amicus%20brief_061312.pdf

[12] https://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf

The Public Service Electric & Gas Company (PSE&G) argues that a MW of demand response does not make the same contribution towards system reliability as a MW of generation, because demand response committed as a capacity resource is only required to perform for a limited number of times over the peak period.

Considerations for Ontario: This argument is the counter-point to the disproportionate benefits argument. Whether the equivalence of the product provided by DR and generating resources is accepted is a main point of contention on utilization payments.

3.1.8 Other Costs Associated with Curtailment

The argument is as follows. For dispatchable loads, electricity is as much an input as an output. The cost of producing a megawatt of electricity for a load is equal to the value of lost load, which can be higher than the price cap imposed in most organized wholesale energy markets (in Ontario the price cap is CAD $2,000 per megawatt-hour).

Another way to think about this argument is that, for a load, the cost of producing electricity in the form of curtailment is equivalent to the lost revenue and additional costs incurred (i.e. lost profit) associated with a reduction in production. DR resources have both fixed costs such the initial investment in technology such as monitoring and controls software to manage and execute DR operational activities and variable costs, such as labor cost and loss of productivity during the DR activation period. This value may vary significantly by DR resource. In jurisdictions where utilization payments are provided, activation levels for DR in the energy market are still relatively low. This suggests that even when provided with a utilization payment, the lost profit or value of lost load may still be much higher.

Considerations for Ontario: For large commercial and industrial customers, the value of lost load (VOLL) can be very high, which could result in limited activation of DR resources regardless of whether utilization payments are offered. Residential customers generally have a lower VOLL ($0/MWh - $17,976/MWh) than commercial and industrial customers (whose VOLLs range from about $3,000/MWH to $53,907/MWh)[13]. Given the sensitivity of VOLL to a variety of specific factors such as customer's consumption profile, a region's macroeconomic and climatic attributes, as well as the types of outage these ranges these ranges may be different for Ontario.

3.2 Considerations for Ontario

The arguments for and against utilization payments are nuanced and prudent. Responsible stakeholders can arrive at different conclusions based on preferences for evaluation criteria.

A unique consideration for Ontario is that today, almost all generation resources are compensated under long-term contract or through regulation that guarantees a certain level of revenue. The economic efficiency arguments under this current market structure are different than they would be if considering the future state of the wholesale power market where generation resources are largely compensated through energy and capacity market revenues. Under the current conditions, more DR activation (as a

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[13] http://www.ercot.com/content/gridinfo/resource/2014/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf

result of bidding into the market at prices lower than traditional generators) would not actually lead to reduced costs to consumers since generators have their compensation guaranteed. In the future when if DR resources compete against generation assets in the capacity market, traditional generators may lose revenue because of being under bid by DR. This would result in reduced (though likely not significant) costs to consumers.

4. WIDER MARKET IMPACTS

Introducing utilization payments for DR can have both direct and indirect impacts on the Ontario electricity system. It is important to consider both types of impacts, particularly in the context of the proposed changes associated with Market Renewal.[14] This section describes the impact on a qualitative basis. Additional effort is required to estimate the quantum of the impacts.

The key question is whether the current Ontario framework of only offering availability payments is sufficient. Considering this:

- Would there be more or different types of DR offered into the market?
- What are the impacts on energy market prices and costs?
- How much and to what extent are other market participants and consumers impacted?

When considering the wider market impacts it is important to keep in mind that if utilization payments do not significantly change the activation levels of DR than the impact on the energy price will be negligible and the additional utilization payments will be minimal.

4.1 Direct Impacts

<u>DR resources change their bids into the energy market and are activated more often</u>
With utilization payments, DR resources would have an incentive to bid values lower than the ceiling price into the energy market as they would receive payment whenever they are activated. Each participating resource would have to determine the value of consuming electricity relative to their avoided cost plus the utilization payment and use that to define their bid into the market. The magnitude of this impact depends on the mix of participating DR resources. Experience in other markets has shown that the impact is likely to be small for traditional DR providers but as technologies change, expanded capabilities and changing business models may result in larger impacts on bidding strategies.

Consider DR aggregators who collect multiple residential or small commercial loads (typically air conditioning) to bid into the energy market. These DR resources have a low value of lost load. If a utilization payment were provided they are likely to bid into the energy market more frequently and at lower prices to get activated more often and get additional revenues.

<u>DR participation increases in both the capacity and energy markets</u>
With the additional incentive of utilization payments, there may be increases in the amount of DR that enters the Ontario system. The magnitude of this impact depends on whether there is a material increase in revenue for traditional DR or if there are viable new business models that can rely on the changed incentives.

Some resource types such as aggregated residential or small commercial loads may have a higher initial cost of DR (such as an incentive cost per customer) but a low value of lost load. If a utilization payment were provided the economics for this type of customer would be more attractive. That would lead to more DR resources offering into the capacity market and more DR resources bidding into the energy market at lower prices. Currently aggregated residential and small commercial load only represents a small amount of DR participation so this is not expected to have a large impact on participation or activations.

[14] Market impacts have to be evaluated in the context of a specific payment structure so the impacts in this section assume that utilization payments are tied to LMP even though there are other utilization payment structures that could be considered.

However, additional technology improvements are leading to more load being available to aggregators for DR participation.

4.2 Indirect Impacts

Energy prices, particularly during price spikes, decrease
If the utilization of DR resources increases, there will be downward pressure on energy prices. The impact depends on whether DR resources change their bids to be below the ceiling price or if there is significant new entry of DR resources due to the changed incentives. If neither of these conditions is true, then the impact on energy prices will be minimal.

As noted above, the introduction of utilization payments may attract more DR resources with higher initial investment but lower value of loss load. This type of resource (e.g. residential AC) is more likely to bid into the energy market at lower prices which would lead to the DR resource being dispatched rather than a more expensive traditional generator. The overall impact would be decreased energy prices though again the impact is not expected to be significant since large C&I customers who represent a significant amount of DR resources typically have a high value of lost load and are not expected to change their bids into the energy market.

Capacity prices change
If DR participation in the market increases and it can meet capacity obligations, then there could be reduced need for other capacity resources. This would put downward pressure on capacity prices. However, reduced energy prices increase the net revenue requirement of traditional resources and they would likely increase their offers into the capacity market which could put upward pressure on capacity prices. The relative impacts of these two dynamics is difficult to estimate.

Considering again aggregated residential or small commercial loads; adding these additional offers into the capacity market will lead to greater competition. Competition generally leads to lower prices however it is possible that traditional generation participating in the capacity auction would need to increase their capacity offers if they anticipated being activated less often and receiving lower revenues through the energy market.

DR resources receive higher revenues
With an additional source of revenue, DR resources would likely receive higher overall revenues. For current market participants, even if they do not change offering/bidding strategies, they would add utilization payments when prices reach the ceiling and they are dispatched. The caveat to the higher revenues is whether there is a reduction in availability prices that offsets the utilization payments.

DR resource with a high value of lost load are unlikely to receive higher revenues. For these resources (typically large C&I customers) it would not be economically efficient for them to change their bids in the energy market even if a utilization payment were provided. For DR resources with lower value of lost load revenues are expected to increase. These resources would bid into the energy market more frequently leading to additional revenues collected through utilization payments.

Improved flexibility
With the additional incentive of utilization payments, there may be increases in the amount of DR that participates in the wholesale market in Ontario. This will lead to additional quick response resources being available to balance the electricity grid which will support system reliability and address resource adequacy.

Activating DR resources rather than traditional supply resources reduce the load on the electricity distribution system which can increase the life of the system equipment and may lead to deferral of capacity projects. They also represent an emissions free resource which leads to additional environmental benefits when these resources are activated rather than traditional supply generators.

System costs change

Each of the indirect dynamics discussed above change the overall system cost. Incremental activation payments to DR providers would increase costs. Decreases in capacity and energy prices would decrease costs. It is challenging to estimate the relative magnitude of the impacts.

If utilization payments are added to the system, but the mix and level of DR participation and activation remains the same, then the overall impact of the change would be minimal. However, if the change resulted in a large increase in participation and activation then the incentives could be a material reduction in system costs.

As described above, if additional residential and small commercial customers participate in the DR auction and then bid into the energy market more often at lower prices they will be activated more often and at a lower price than traditional generators. This will lead to lower overall system costs.

However, if all resources who participate in the DR auction continue to be large C&I customers with value of lost load higher than the energy ceiling price, DR resources will likely continue to bid into the energy market at the market ceiling price and will not be activated any more than they are now. Under this scenario, no changes in system costs would be expected.

Production Losses

With the additional source of revenue some DR resources may be incented to bid into the energy market at lower prices leading to more frequent curtailment. This could lead to declines in the domestic production of other goods, which in turn could change the price of these goods in the economy. These impacts are expected to be minimal, as jurisdictions that added or increased utilization payments did not realize a significant increase in the activation levels of DR.

As described above, if a company which is producing widgets is incentivized through utilization payments to curtail their load and stop producing widgets fewer widgets will be available to buy. This reduced supply may increase the price of the widgets in the market. In practice, the impact of providing a utilization payment is not expected to be significant enough to cause a material impact on supply of goods (widgets) in the market.

5. SUMMARY OF DR PARTICIPATION IN OTHER JURISDICTIONS

5.1 Jurisdictions with Relevant DR Programs

DR is a common resource in organized wholesale power markets. Navigant reviewed markets that have a history of DR, ideally within a power market framework. Navigant reviewed the products in each jurisdiction that are most applicable to Ontario. These include both economic/energy DR and reliability/capacity DR.

In many jurisdictions, the same DR resource can participate in both an economic/energy and reliability/capacity programs at the same time, which allows them to collect both availability and utilization payments. DR can participate in ancillary service markets in many jurisdictions, however, the requirements for these markets are very specific and the use of utilization payments in these markets is widely accepted. For this reason, ancillary services DR is not discussed within this section but is covered in Appendix A, where additional cross-jurisdictional details are provided.

The jurisdictions reviewed were selected to cover diverse geography, payment structures, and payment levels. Navigant reviewed publicly available documentation for all jurisdictions to understand the DR resource requirements and payment structures. Interviews were also conducted with contacts at the PJM, CAISO, ERCOT, AEMO (Australia) and with an expert on the DR auction in South Korea.

Most markets in the US are FERC jurisdictions and because of the recent FERC ruling have a requirement to provide utilization payments. As a result, Navigant and the IESO identified a need to examine jurisdictions outside of North America as well. Within the US, PJM was selected since it represented the most established market for DR participation in power markets. California was selected to cover innovative ways of incorporating DR into power markets through the DRAM mechanism. New York was selected as a less mature jurisdiction which also included the types of DR being examined (economic and reliability). ERCOT was selected as a non-FERC US jurisdiction which represents alternative compensation mechanisms to FERC jurisdictions. Outside of North America, Navigant and the IESO worked to identify regions with applicable DR programs (economic and reliability) that are relatively well established. This led to the identification of Finland (which is a relatively well establish region for DR participation in the power markets), France (which is also a well-established DR market and has recently introduced a capacity certificate program), Australia (which has recently gone through a review process for potential introduction of a DR mechanism that would allow aggregators to bid DR into power markets) and South Korea (which has very recently added DR participation to the power markets).

Seven of the eight jurisdictions examined have economic DR. Five of the eight jurisdictions have reliability DR.

5.2 Payment Structures and Levels

5.2.1 Economic DR

Navigant examined the features of economic DR across all jurisdictions. The economic DR products are like the IESO's existing DR market structure, in that they bid directly into the wholesale energy market and are dispatched using the ISOs' security constrained dispatch algorithm. They differ from the IESO's existing DR market structure in that they receive utilization payments for the provision of economic/energy DR. Economic DR resources do not receive capacity payments in exchange for bidding into the energy market.

The jurisdictions reviewed include FERC jurisdictions (California, NYISO and PJM) and non-FERC jurisdictions (France, Finland, Australia, South Korea). ERCOT does not have an exclusively economic/energy DR product. In 2011, the FERC in the US ruled that DR resources bidding into the Day-Ahead and Real-Time energy markets should be paid the full locational marginal price (LMP) like other generation resources bidding into the markets. This set a requirement for California, NYISO and PJM to provide utilization payments equivalent to LMP.

All three jurisdictions opposed FERC Order No. 745 and have suggested that LMP minus generation is a more appropriate payment level. Australia, France, Finland and South Korea are non-FERC jurisdictions. These jurisdictions provide a utilization payment equal to the wholesale energy price. For the two jurisdictions where Navigant completed interviews (Australia and South Korea) this incentive level was reported to have been selected based on consistency, since the DR resources are participating in the energy market like other supply resources.

Some key features of the payment structures and levels for energy/economic DR are noted below.

1. In all jurisdictions reviewed resources that provide economic/energy DR receive utilization payments.
2. In jurisdictions that also procure reliability/capacity DR, resources can participate in both (and receive availability payments for providing reliability DR and utilization payments for providing economic DR).
3. Participation and activation levels vary considerably by jurisdiction.
    - In NYISO no resources have bid into the energy market even though the program is available to do so. This may indicate that the cost to curtail is higher than the ceiling price.
4. Some jurisdictions have a floor price for DR bidding into the wholesale energy market. FERC Order No. 745 set a net benefit price requirement that represents the price at which the benefits incurred by a reduction in wholesale prices from the economic DR will exceed the cost to pay for the economic DR. The net benefit price is set as the minimum price at which DR can bid into the market.
5. The magnitude of the utilization payment has been debated across regions (e.g. wholesale market clearing price vs. wholesale market clearing price minus cost of generation).

Jurisdiction	Name of Service	Notification Time	Utilization Payment Levels	Participation
California	Proxy DR	Day Ahead (by 3pm) or Real Time	Wholesale market clearing price	160[15] MW
NYISO	Day-Ahead DR Program (DADRP)	Day-ahead and 2-hours prior	Wholesale market clearing price	0 MW (No bidding activity since 2010)
Mid Atlantic US (PJM)	Economic DR	30 minutes	Wholesale market clearing price	2,096 MW in 2017 (decreasing or stagnant)
France	NEBEF Energy Wholesale	Day ahead or Real Time	Wholesale market clearing price	600-1000 MW[16]

[15] https://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf

[16] http://www.smartenergydemand.eu/wp-content/uploads/2015/09/Mapping-Demand-Response-in-Europe-Today-2015.pdf

Jurisdiction	Name of Service	Notification Time	Utilization Payment Levels	Participation
Finland	Elspot & Elbas	Day ahead or Intraday	Wholesale market clearing price	200-600 MW Day-Ahead; 0-200 MW Intraday
South Korea	Load Curtailment	Day Ahead	System Marginal Price	Unknown
Australia	Economic DR	Day Ahead	Wholesale market clearing price	Unknown

5.2.2 Reliability DR

Five of the eight jurisdictions examined have reliability DR programs. These programs are like the IESO DR market structure from the perspective that they provide an availability payment in exchange for the ability to use DR in a reliability event. In some jurisdictions, reliability resources also receive utilization payments when activated. They are also able to participate in economic DR programs that can lead to higher levels of activiation for which they are further compensated with additional utilization payments. They differ from the IESO DR market structure in that these resources are not also required to bid into the energy market. They are dispatched administratively by the ISOs.

In addition to the five jurisdictions with reliability DR that is integrated into power markets, France has a capacity mechanism that acts as a decentralized market which does not interface with the energy market. Generators and suppliers trade capacity certificates. Capacity certificates come with a right to the corresponding energy. DR resources are eligible to participate in the capacity mechanism. By trading capacity certificates, DR resources would be able to collect a payment that would be analogous to an availability payment. No additional energy payments are received.

DR resources in PJM, NYISO, and South Korea are all able to participate in both economic/energy and reliability/capacity programs. They are provided an availability payment through the capacity/reliability program in exchange for being available to be dispatched during a reliability event. They are also paid a utilization payment when dispatched by clearing the energy market or when dispatched administratively by the ISO through reliability DR.

California recently introduced a Demand Response Auction Mechanism (DRAM), which is a pay-as-bid auction of monthly local, system, and flexible capacity for third party offerors. Bidding in the DRAM is done by the utilities rather than customers themselves. Each utility has a target of DR capacity that they are required to acquire.

Some key features of the payment structures and levels for reliability/capacity DR are noted below.

1. Resources that are participating in the reliability DR programs receive availability payments for being available in a reliability event.
2. Resources are dispatched administratively, they are not typically dispatched by the ISOs' security constrained economic dispatch algorithm.
3. When activated, reliability DR resources are paid a utilization payment in 4 of the 5 jurisdictions.
4. Resources can participate in both reliability/capacity and economic/energy DR programs. In theory, this enables higher levels of activation, as DR resources are dispatched when economic and for reliability reasons. Both reliability and economic dispatch are compensated by utilization payments.

5. For NYISO and PJM, participation in the reliability DR programs is significantly higher than participation in the economic DR programs.[17] This suggests that wholesale prices are not high enough for many customers to be incented to reduce demand and that the availability payment is a larger driver.

Jurisdiction	Name of Service	Notification Time	Payment Type & Level	Participation
California	DRAM	Day Ahead (by 3pm) or Real Time	Availability & Utilization (Wholesale price)	200 MW under contract for 2018/19[18]
NYISO	Installed Capacity – Special Case Resource (ICAP-SCR)	2 hour and Day Ahead	Availability & Utilization (Wholesale price)	1,192 MW 2016[19]
Mid Atlantic US (PJM)	Limited, Extended Summer, Annual, Base DR	30 min	Availability & Utilization (Wholesale price)	9,123 MW 2016[20]
Texas - ERCOT	ERS or Load Resources	10 min or 30 min	Availability Payment	896 MW (Oct 17-Jan 18)[21]
South Korea	Capacity DR	1 hour	Availability & Utilization (Wholesale price)	3,885 MW 2016[22]

5.3 Motives and Outcomes

DR is playing an expanding role in electricity systems in many jurisdictions. Participation levels vary across jurisdictions and have been impacted by the magnitude of the availability and utilization payments available. Anecdotally, jurisdictions with higher wholesale prices have experienced higher levels of DR activation.

In the jurisdictions reviewed by Navigant, only utilization payments are made to DR resources for economic/energy DR. Availability payments and utilization payments are made to reliability/capacity DR resources.

PJM, NYISO, and CAISO are all FERC jurisdictions and are required to follow FERC Order No. 745. Under this order, FERC requires ISOs to compensate DR when activated with utilization payments equal

[17] This may also be true for South Korea, however, the economic DR participation is not available publicly.

[18] Program is still in pilot phase

[19] http://www.nyiso.com/public/webdocs/markets_operations/market_data/demand_response/Demand_Response/Reports_to_FERC/2017/NYISO%202016%20Annual%20Report%20on%20Demand%20Response%20Programs_Final.pdf

[20] https://pjm.com/~/media/markets-ops/dsr/2017-demand-response-activity-report.ashx

[21] http://mis.ercot.com/misapp/GetReports.do?reportTypeId=11465&reportTitle=ERS%20Procurement%20Results&showHTMLView=&mimicKey

[22] South Korea has recently moved from a contract model to market based participation. Not clear how much of the DR is actually being activated in the energy market.

to LMP. Proponents of this ruling argued that DR resources should be paid like other supply resources, since they are providing a similar product and the gains seen through bill reductions only cover a portion of the variable costs incurred by the DR resources when curtailed. Many of the ISOs in the US argued that paying the full LMP was overcompensating DR. The ISOs recommended compensating the DR provider as if it had first purchased the power it wishes to resell to the market.[23]

PJM indicated during an interview with Navigant that it does not support the full LMP utilization payment, because it is an implicit subsidy. They noted that the introduction of LMP utilization payments lead to higher activation levels, though not significantly, leading to an immaterial impact financially. Long term, PJM wants to revisit the payment structure. ERCOT, which does not have to follow FERC Order No. 745, elected to not provide utilization payments since DR resource customers are receiving the wholesale energy price signal.

Following the FERC ruling, jurisdictions experienced higher, though not significantly, DR activation levels. Following FERC Order No. 745, PJM reported:

- an increase in energy market participation;
- an increase in the amount of energy market activity in the day-ahead market; and
- better performance (actual delivered load reductions closer to amount dispatched in real-time market or cleared in day-ahead market).

PJM indicated the potential for a significant increase in economic DR activity, since most DR resources who are registered have not submitted offers into the real-time or day-ahead market and the majority of emergency DR resources do not participate as an economic DR resource. The average megawatts settled after FERC Order No. 745, relative to immediately before, grew (approximately 20 MW to over 60 MW). However, the utilization factor for DR in the energy market is still only a very small fraction (~3 percent) of the overall DR capability. Only a small percentage of the DR which is registered is activated through the energy/economic DR. This suggests that wholesale prices are not high enough for most customers to be incented to reduce demand.[24]

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[23] http://www.caiso.com/Documents/FinalSupplementalOpiniononEconomicIssuesRaisedbyFERCOrder745.pdf

[24] http://pjm.com/-/media/markets-ops/dsr/20150701-order-745-impact-on-economic-dr.ashx?la=en

APPENDIX A. ADDITIONAL JURISDICTIONAL SCAN DETAILS

Navigant reviewed publicly available documentation for each of the jurisdictions selected to determine:

1. What types of DR (economic/energy, capacity/reliability, etc.) does each jurisdiction procure from loads.
2. The structure (market-based, program-driven, etc.) used to remunerate loads for providing these services. In particular, to determine whether DR resources are offered utilization payments in addition to (or instead of) availability payments.
3. Where utilization payments *are* offered, how those payments are made, e.g., a fixed payment per event, LMP-based, etc.

Navigant was also able to complete interviews with contacts from 5 jurisdictions (PJM, CAISO, ERCOT, Australia and South Korea) to discuss the motivations behind providing the incentive types they offer.

The table below provides a summary of the jurisdictional scan findings and is followed by a detailed description of each jurisdiction.

Table 1: DR Jurisdictional Scan Summary

Jurisdiction	Type of DR	Name of Service	Notification Time	Payment Type	Bid into wholesale markets?
California	Emergency	Optional Binding Mandatory Curtailment Program	15 min	Contract payment	No
	Economic	Proxy DR	Day Ahead (by 3pm) or Real Time	Utilization payment	Real Time and Day Ahead
	Capacity	System/Flexible/Local DR	Day ahead or Real Time	Capacity & Utilization payment	DRAM auction
New York (NY-ISO)	Emergency	Emergency DR Program (EDRP), Installed Capacity – Special Case Resource (ICAP-SCR)	2 hour and Day Ahead	Contract payment	No
	Economic	Day-Ahead DR Program (DADRP)	Day ahead or Real Time	Utilization payment	Day ahead or Real Time
	Ancillary	Demand Side Ancillary Services Program (DSASP)	Fully Automated, 4 s, 10 min	Spot price for service	Ancillary services market
Mid Atlantic US (PJM)	Emergency	Limited, Extended Summer, Annual, Base DR	30 min	Availability Payments & Energy Payments	Real time and Day Ahead
	Economic	Economic DR	Day ahead or Real Time	Utilization Payment	Real time energy markets

Jurisdiction	Type of DR	Name of Service	Notification Time	Payment Type	Bid into wholesale markets?
	Ancillary	Synchronized reserve, Frequency regulation	10 min or 30 min	Spot price for service	Ancillary services market
Texas (ERCOT)	Emergency	Emergency Response Service	10 min or 30 min	Availability Payments	No
	Capacity	Load Resource	5 min	Availability Payments	Real time energy markets
	Ancillary	Responsive Reserve	Fully automated, 4 s or 10 min depending on service	Spot price for service	Ancillary services market
France	Economic	NEBEF Energy Wholesale	Day ahead or Real Time	Utilization (spot price) payments	Day Ahead and Intraday
	Balancing, Ancillary Services and Reserves	Balancing, Ancillary Services and Reserves	<30 s, < 400 s, 13 min, 30 min depending on service	Availability & Utilization payments	Ancillary service markets
	Capacity	Capacity Mechanism	Day Ahead	Decentralized market which does not interfere with the energy market	No
Finland	Economic	Elspot & Elbas	Day ahead or Real Time	Utilization Payments	Day ahead or intraday
	Ancillary	FCR-N, FCR-D, FRR-A, Balancing Power market	Automatic, 5 s, 30 s, 2 min, 15 min based on service provided	Availability & Utilization Payments	Ancillary service markets
Australia	Ancillary	Ancillary services	6 s, 1 min, and 5 min depending on product	Spot price for service	Ancillary services market

Jurisdiction	Type of DR	Name of Service	Notification Time	Payment Type	Bid into wholesale markets?
South Korea	Economic	Load Curtailment	Day Ahead	Utilization Payment (System Marginal Price)	Real time and day ahead market
	Capacity	Capacity DR	1 hour	Availability & Utilization Payments	No

A.1 New York (NYISO)

DR programs in NYISO can be broadly classified into two categories, reliability DR and economic DR. Participants in NYISO can participate in one reliability and one economic DR program in parallel. Participation in both programs in parallel is most closely aligned to the IESO DR auction. When participating in both, participants receive an availability payment (through the reliability program) and bid into the wholesale energy market (through the economic program). Some key differences should be noted: (1) participants can be activated administratively (because of a reliability event) through the reliability program (2) participants receive a utilization payment when activated through either the reliability or economic programs.

Reliability Based Programs*:* During periods of increased demand, or when the grid is affected by unplanned events such as inclement weather, the NYISO's market pays participants in these programs for load reductions that lessen stress on the electric grid. Program rules unique to the ICAP-SCR program also enable participants to receive monthly payments (called "capacity payments") based on the obligated level of load reduction (i.e., the committed level of load reduction at the facility when the NYISO requests that participants reduce load). There are two reliability based program available:

- Installed Capacity – Special Case Resource (ICAP-SCR) program
- Emergency DR Program (EDRP) program

Economic Based programs*:* These programs provide participants the opportunity to offer load reduction into New York's electricity markets in response to high electricity prices. Day-Ahead DR Program (DADRP) participants submit to the NYISO an "energy offer" to reduce consumption at the price the participants determine. Similarly, Demand Side Ancillary Services Program (DSASP) participants submit "reserves" and/or "regulation" service offers to the NYISO. If the offer is accepted and scheduled by the NYISO, DSASP participants are eligible to receive market payments based upon actual performance.

Table 2: NYISO Capacity and Energy Market Summary

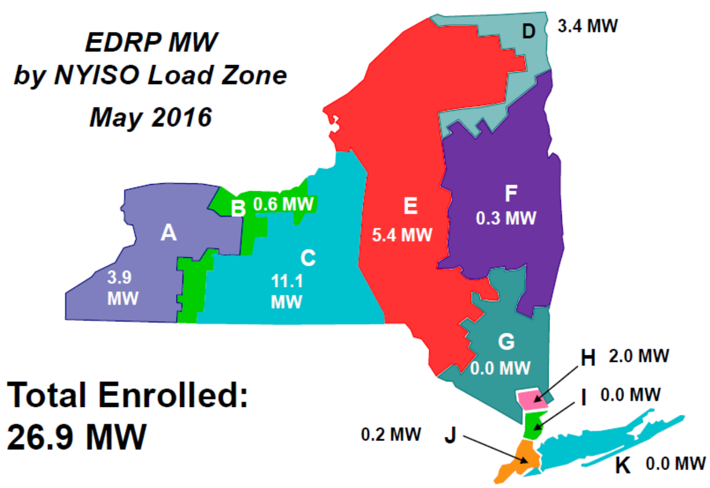
Category	Capacity Market	Energy Market
Program Period	Annual (can bid seasonally or monthly)	Annual (bid at will)
Event Windows	Anytime	Based on bidding and clearing
Dispatch Limits	4 hours	Based on bidding and clearing
Notification Time	Day-ahead and 2-hours prior	Day-Ahead or Real-Time, based on bidding and clearing
Curtailment Limits	None	Based on bidding and clearing
Tests	1 per season (Summer and Winter)	N/A
Enrollment Deadlines	Monthly	Daily bidding
Payments	Monthly	Monthly
Minimum Size	100 kW	1 MW

Category	Capacity Market	Energy Market
Metering Requirements	1 hour	1 hour
Baselines	Average Coincident Load (highest 20 hours of load in the system 40 peak hours)	Customer Baseline: High 5 of 10 days

Source: Navigant Research and NYISO website

The ***Installed Capacity (ICAP) Special Case Resources (SCR) program*** provides financial incentives for electricity consumers larger than 100 kW to reduce their electricity use or operate on-site generation during periods of electricity reserve shortage. NYISO provides 2-hour notice of curtailment events as well as day-ahead advisories. Participants receive two separate payment streams: a capacity payment based on their committed load reduction and energy payments for their actual load reductions during curtailment events. Participants face non-compliance penalties if they do not curtail their committed amount when called by NYISO. Individual customers must participate through an authorized Responsible Interface Party (RIP) who coordinates transactions with NYISO, and cannot commit the same resources in both the Emergency DR program and the SCR program.

Figure 1: Summer 2016 EDRP Enrollment



Source: NYISO's Semi-Annual Report to FERC (June 1, 2016)

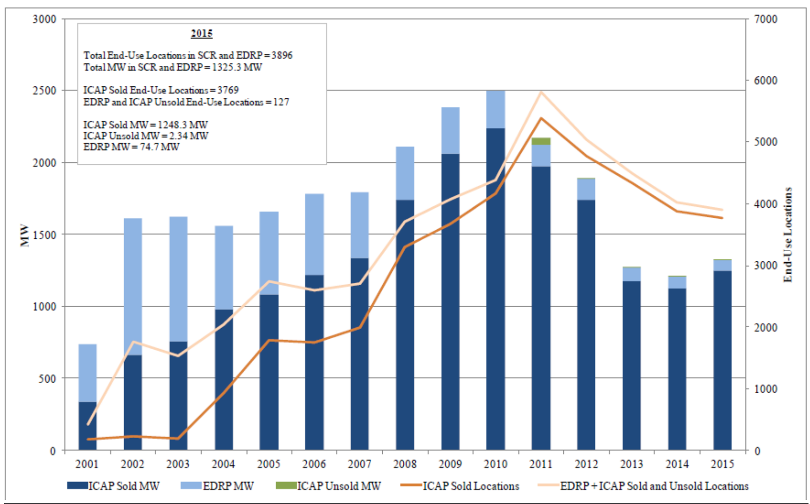
Payment: Monthly Capacity payments are based on sales made through ICAP auctions or bilateral contracts. The energy payments are based on performance in events & tests; Locational Based Marginal Pricing (LBMP) with daily guarantee of strike price recovery.

The ***Emergency DR Program (EDRP)*** provides financial incentives for electricity users to voluntarily reduce consumption and/or operate on-site generation during periods of electricity reserve shortage in New York. NYISO typically provides 2-hour notice of curtailment events as well as day-ahead advisories (although in some cases immediate deployment is requested). Participants receive the higher of $500/MWh or the real-time zonal Locational Based Marginal Price (LBMP) for their curtailments.

Participation in any curtailment event is voluntary, and there are no penalties for non-performance. Individual customers can either participate directly in EDRP (if their load reduction is at least 100 kW) or through an authorized curtailment service provider (CSP), such as a utility, energy service company, or curtailment customer aggregator. Customers cannot participate in both the Emergency DR Program and the Installed Capacity Special Case Resources (SCR) program (see above). EDRP and SCR are dispatched separately by NYISO, with SCR resources dispatched first, and EDRP customers called only if additional resources are needed.

Payment: The energy payments are based on measured energy reduction during an event, with a minimum rate of $500/MWh or the actual LBMP, if higher.

Figure 2: Historical Program Growth SCR and EDRP



Source: NYISO's Semi-Annual Report to FERC (January 12, 2016)

Table 3: NYISO EDRP & SCR Events and Payments

Summer	#Resources and Registered MW	Events	Avg Hourly Response	Energy Payments	Avg. payment per MWh
2009	4,067 2,384 MW	No events	N/A	N/A	N/A
2010	4,386 2,498 MW	31 hours downstate 19 hours TDRP, plus 12 ICAP/SCR & EDRP	1.85 MW (TDRP) 178.1 MW (ICAP/SCR & EDRP Energy)	$1.09 million	$500
2011	5,807 2,173 MW	11 hours downstate 5 hours Upstate	7/21/11: 414 MW 7/22/11: 1065.2 MW	$3.8 million	$500

Summer	#Resources and Registered MW	Events	Avg Hourly Response	Energy Payments	Avg. payment per MWh
2012	5,032 1,888 MW	39 hours Downstate including 9 hours TDRP, 30 hours ICAP/SCR & EDRP, 20 hours Upstate ICAP/SCR & EDRP	3.6 MW (TDRP) 1196 MW (June 21 Statewide ICAP/SCR & EDRP)	$5.9 million	$514
2013	4,495 1,270 MW	27 hours Downstate 10 hours Upstate	915.2 MW (July 19 Statewide ICAP/SCR & EDRP)	$6.9 million	$524
2014	3,704 900 MW	6 hours Statewide	236.2 MW (Jan 7 ICAP/SCR & EDRP)	$346,356	$509
2015	3,896 1,325 MW	No events	N/A	N/A	N/A

Source: NYISO website

The ***Day Ahead DR Program (DADRP)*** provides electricity users with the opportunity to bid load reductions into New York's day-ahead wholesale electricity market, where their bids compete with generators' offers to meet the state's electricity demand. At their discretion, customers can submit load reduction bids on a day-ahead basis by indicating the load reduction amount, price (between $50 and $1,000 per MWh), and time period. If the customer's bid is accepted and the customer fully curtails, they receive payment for their accepted bid, based on the greater of the bid price or the day-ahead LBMP.

If the customer fails to fully curtail, they will pay the higher of the day-ahead price (LBMP) or the real-time price for the amount of incomplete scheduled load reduction. Individual customers can either participate directly in DADRP if their load reduction is at least 1 MW, or through an authorized curtailment service provider, such as a utility, energy service company, or a curtailment customer aggregator. Most of these providers require a customer to be able to reduce load by at least 100 kW in each hour. Unlike in the EDRP and SCR programs, standby generators are not eligible for participation. Day-ahead participants can also be registered in EDRP.

DADRP enrollment has been static for several years and enrolled resources have not submitted demand reduction offers for more than four years. DADRP enrollment remained unchanged since the January 2016 Report.

Payment: The incentive payment is the product of Day-Ahead LBMP (wholesale market clearing price) and the lesser of actual or Day-Ahead scheduled load reduction. The curtailment initiation can be paid on a daily basis, if applicable. Some program providers allow customers to bid both a price for each hour's load reduction bid and an additional amount, called the curtailment initiation cost (CIC). The CIC places a floor on the total payment received if the bid is accepted.

NYISO also offers a ***Demand-Side Ancillary Services Program (DSASP)***, through which loads can provide 10- and 30-minute non-spinning operating reserves. To participate, registered demand-side resources submit availability bids to the day-ahead market. If these bids are accepted, the demand-side customer is paid the market clearing price for that level of reserves (e.g., 10- or 30-minute). In return, the customer must comply with load reduction signals from NYISO. If the resource is asked to actually reduce demand in real time, it will also be paid the real-time market price for energy. If the customer changes its operating reserve offer in real time, the difference between this and the day-ahead reserve amount is financially settled at the real-time operating reserve price. A demand-side resource cannot offer the same capacity in the DADRP and DSASP on the same day.

For DSASP, participants have to get modeled in the NYISO system model and the undergo testing before being allowed to participate. Historical participation is low, around 150 MW.

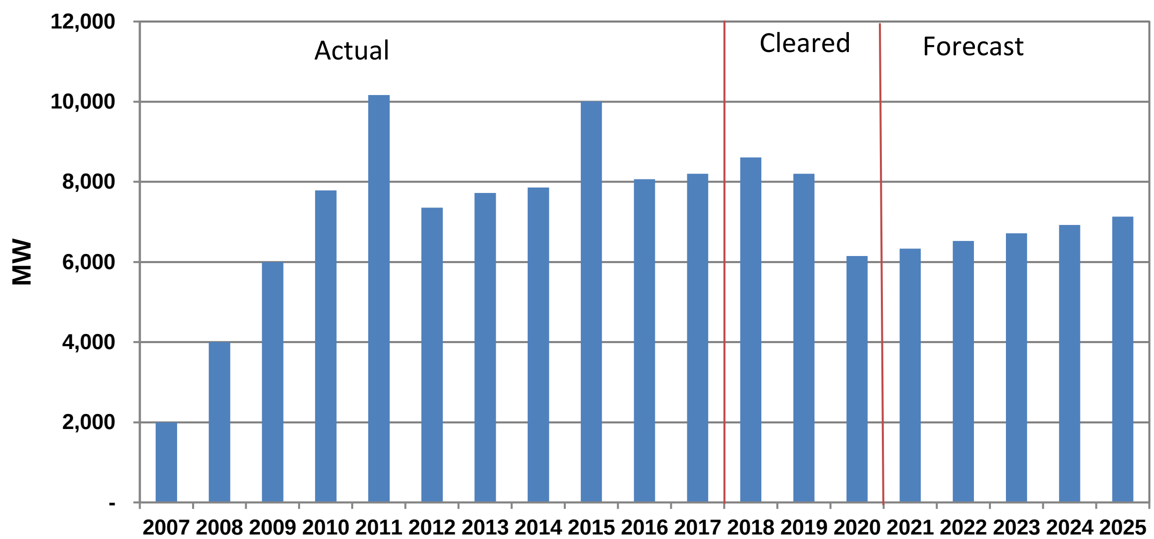
Payment: Resources are paid marginal clearing prices for Ancillary Service product scheduled. This price is based on auction clearing price which is dependent on location and the product.

A.2 PJM

PJM's DR opportunities enable retail electricity consumers to earn a revenue stream for reducing electricity consumption when either wholesale prices are high or the reliability of the electric grid is threatened. DR participation is broken in two broad classifications, economic and emergency. An electricity consumer may participate in either or both depending on the circumstances. In the PJM region, DR has accounted for as much ~10% of the total.

Similar to NY, resources in PJM territory can participate in both the economic and emergency programs in parallel. The emergency program provides an availability payment and if activated (either administratively through the emergency program or based on wholesale price in the economic program) they receive a utilization payment.

Figure 3: PJM Historical and Projected DR volume



Source: PJM data and Navigant estimates

Pre-Emergency and Emergency DR primarily represents a mandatory commitment (referred to as Load Management Resources AND Demand Resources (DR)) to reduce load or only consume electricity up to a certain level when PJM needs assistance to maintain reliability under supply shortage or expected emergency operations conditions. This is considered a mandatory commitment to which penalties are applied for noncompliance. The Curtailment service provider's (CSP) resources must be available to respond to PJM's request to reduce load where the availability depends on the product selected by the CSP as follows:

- ***Limited DR*** (only available through 17/18 Delivery Year) – resource is available for up to 10 weekdays from June through September, where each request may be up to six hours in duration.
- ***Extended Summer DR*** (only available through 17/18 Delivery Year) – resources are available for all days from May through October, where each request may be up to ten hours in duration
- ***Annual DR*** – resources is available for all days from June through May of following year, where each request may be up to 15 hours in duration
- ***Base DR*** (only available for 18/19 and 19/20 Delivery Years) – resource is available for all days from June through September, where each request may be up to ten hours in duration

Table 4: PJM Capacity Market DR

Category	Current	Capacity Performance
Program Period	Summer (June-September)	Annual
Event Windows	12-8 PM	May-Oct: 10 am-10 pm; Nov-Apr: 6 am-9 pm
Dispatch Limits	6 hours per event	None
Notification Time	30 minutes	30 minutes
Curtailment Limits	10 events	None
Tests	1 per year	1 per year
Enrollment Deadlines	May each year	May each year
Payments	Monthly	Monthly
Minimum Size	100 kW	100 kW
Metering Requirements	1-hour interval meter	1-hour interval meter
Baselines	Firm Service Level using Peak Load Contribution	Firm Service Level using Peak Load Contribution (Summer and Winter)

Source: PJM Website and Navigant Research

As of 2017, PJM will only procure Annual Capacity performance products. PJM considers these resources like a generator and fully expects them to perform at the time when the grid most needs it to avoid brownouts and/or rolling blackouts within the PJM service territory. The CSP is responsible for managing their portfolio of customers to meet their obligations and avoid creating an operational problem on the grid and/or receiving financial penalties.

The revenue stream derived from participation is largely driven by the "Capacity" market as defined under the Reliability Pricing Model (RPM). The revenue earned is a function of the relevant price and the load reduction commitment. The resource is paid to be “available” during expected emergency conditions on a monthly basis for a commitment that is made for one year, which starts on June 1 and ends on May 31 of the following year.

Emergency DR (Load Management) Event Penalties are assessed by curtailment service providers and distributed, as a bonus, to resources that perform above expectations, based on the ratio of the relevant resource’s bonus performance level to the total bonus performance from all resources over the same Performance Assessment Hour.

Economic DR primarily represents a voluntary commitment to reduce load in the energy market when the wholesale price is higher than the published monthly PJM net benefits price. The net benefit price represents the price at which the benefits incurred by a reduction in wholesale prices from the economic DR will exceed the cost to pay for the economic DR. The economic DR will be used to displace a generation resource and PJM expect the resource to perform and will assess deviation charges if the amount of load reductions realized is significantly different than the amount of load reductions dispatched by PJM.

An economic DR resource may also provide **Ancillary Services** to the wholesale market with the appropriate infrastructure and qualification by PJM. There are three Ancillary Services markets in which economic DR resources may participate: Synchronized Reserves (the ability to reduce electricity consumption within 10 minutes of PJM dispatch), Day-Ahead Scheduling Reserves (the ability to reduce electricity consumption within 30 minutes of PJM dispatch) and Regulation (the ability to follow PJM’s regulation and frequency response signal). Participation in the market is voluntary; however, if a resource clears, performance is mandatory. PJM fully expects the CSP to perform to maintain system reliability. Currently, there are several electricity customers that provide synchronized reserves into the wholesale market.

Table 5: PJM Energy Market DR

Category	Description
Program Period	Annual (bid at will)
Event Windows	Based on bidding and clearing
Dispatch Limits	Based on bidding and clearing
Notification Time	Day-Ahead or Real-Time, based on bidding and clearing
Curtailment Limits	Based on bidding and clearing
Tests	N/A
Enrollment Deadlines	Daily bidding
Payments	Monthly

Category	Description
Minimum Size	100 kW
Metering Requirements	1 hour
Baselines	Customer Baseline: High 4 of 5 days

Sources: Navigant Research

A.3 California (CAISO)

California is going through a period of transition in their DR market. Utilities run DR programs in California[25] through bilateral contracts with customers and DR aggregators and DR Auction Mechanism (DRAM). In the future, DR will be allowed to participate directly in CAISO markets. The DRAM in California or the Proxy DR is most closely aligned with the DR auction in Ontario since this program will involve bidding DR resources directly into the market. However, in the DRAM, the bidding will be done by the utilities rather than the customers themselves. Each utility has a target of DR capacity that they are required to acquire. Since CAISO is a FERC jurisdiction, customers are paid full LMP based on energy bid into the market.

As part of an effort to replace utility DR programs into demand- and supply-side resources and then integrate DR resources into the California Independent System Operator's (CAISO) markets by 2018, the California PUC established a ***DR Auction Mechanism (DRAM)*** pilot for third parties to provide DR outside of utility programs. During the pilot, the IOUs and third parties offer portions of their own DR portfolios into the CAISO market.

It is a pay-as-bid auction of monthly local, system, and flexible capacity for Offerors to bid directly in the California Independent Operator System ("CAISO") market. Offerors must bid directly into the CAISO energy market and any resulting revenues or liabilities allocated solely to the Offeror.

- ***System Capacity***: IOU-wide, can be bid into CAISO market. Must bid per CAISO must-offer obligation in day ahead and/or real-time market.

- ***Local Capacity***: Must be located in Local Capacity Areas (LCAs). For SCE, covers the LA Basin and Big Creek/Ventura Substations; for PGE, Local Capacity Product must be within one of PG&E's seven LCAs; SDG&E, entire service area. Same must-offer obligation (MOO) as System.

- ***Flexible Capacity***: Bids in to Day Ahead and Real Time Energy market, able to ramp and sustain energy output for a minimum of three hours, must be a PDR resource. Addresses variability and unpredictability created by intermittent resources. Must bid per CAISO must-offer obligation for flexible resources.

Offeror's DR resource shall be comprised of a Proxy Demand Resources ("PDR") or Reliability DR Resource ("RDRR") or multiple PDRs and RDRRS that aggregate customers.

Proxy DR (PDR) resources can be bid economically in the day-ahead and real-time markets as supply. The total amount of proxy DR that was awarded in the day-ahead market decreased by almost half in

[25] https://energy.gov/eere/femp/energy-incentive-programs-california

2016 from the previous year. Day-ahead market awards for proxy DR were most significant in June, July and September on several days with particularly high day-ahead forecasts and peak system loads.

The total amount of proxy DR capacity registered in 2016 decreased to about 160 MW from almost 200 MW during 2015. Only a fraction of this capacity was bid into the market. Between June and December, scheduling coordinators bid in a combined average of about 10 MWh of proxy DR capacity for about 4 hours during peak weekday periods.

The current Commission DR requirements to qualify for local and flexible Resource Agency mandate the DR resource to bid into the CAISO energy market under the CAISO Must-Offer Obligation (MOO) for DR as one or more PDR(s) or RDRR(s) as defined in the CAISO Tariff.

Many utility programs also provide DR opportunities:

The ***Automated DR (Auto-DR) program*** provides free technical assistance and incentives to customers of PG&E, SCE, and SDG&E for installing automated DR equipment.

Participation is open to customers enrolled in a qualifying DR or time-varying pricing programs (PG&E's Peak Day Pricing or SCE and SDG&E's Critical Peak Pricing program). Auto-DR uses communication and control technology to automatically implement the customer's chosen pre-programmed load reductions, providing a fast and reliable way to respond to peak events, while still leaving the customer in complete control.

Incentives range from $125 to $400/kW of reduction capability, depending on level of automation and utility. Eligible equipment includes energy management systems and software, wired and wireless controls for lighting, HVAC, thermostats, motors, pumps and other equipment capable of receiving curtailment signals. SCE also offers the Auto-DR Express program to smaller customers (up to 400 kW peak demand).

The Base Interruptible Program (BIP) offered by PG&E, SCE, and SDG&E pays participants to reduce electric load to (or below) a level pre-selected by the customer (called the firm service level or FSL) that is below its historic average maximum demand. Customers receive a monthly incentive payment or credit based on the size of the curtailable portion of their load, in return for committing to reduce to the FSL when called upon by the utility with thirty minutes' notice. The incentives typically range from $7 to $9 per committed kW per month, even if no events are called. There is a minimum curtailment commitment of 100 kW, or 15% of the monthly average peak demand (whichever is larger). PG&E and SDG&E also offer a longer, 3-hour, notice in exchange for a lower incentive option ($3/kW), and SCE offers a shorter, 15-minute notice option for a higher incentive. Requests for curtailments (which can last up to four hours) cannot exceed one per day, ten per month, or 120 hours per year (90 hours for the lower incentive options). Penalties apply for customers that fail to reduce load as requested—the amount depends on the utility and the incentive option.

All three utilities have contracted with numerous third-party aggregators who recruit customers to participate in BIP and manage their participation process. By serving as an intermediary, the aggregators can handle many of the details on customer's behalf and help them develop load reduction strategies. The aggregators may also offer innovative program features – for example, by assuming the risk of non-compliance penalties or by allowing customers to participate who might otherwise be too small to enroll directly in the utility's program. BIP participants are also be eligible for simultaneously participating in one of the other DR programs, (e.g., time-varying pricing or PG&E/SCE's Demand Bidding Program), which allows customers to take advantage of rate credits, reduced energy charges and incentives associated with both programs, with some restrictions.

Under the ***Capacity Bidding Program*** (CBP), PG&E, SCE, and SDG&E participants receive a monthly incentive for pledging to reduce their energy use to a pre-determined amount in the event a CBP event is called by the utility, which can occur weekdays from May through October, 11 a.m. to 7 p.m. The program offers either a day-ahead or day-of notification option. Customers receive the monthly payment (varies by utility, time of year and notification option) whether an event is called. Failure to reduce the pledged amount during an event will result in reduced incentives and possible penalties for not meeting at least 50% of the pledge. Customers typically enroll in CBP through a third-party aggregator, who manages their participation and relays their monthly reduction pledge, which can vary. Participants can opt for day-ahead notification, or receive higher incentive levels by choosing "day of" event notification. PG&E CBP participants may also be eligible to concurrently participate in additional PG&E DR programs.

Critical Peak Pricing (CPP) from SCE and SDG&E (also called the Summer Advantage Incentive) is a rate structure that offers lower electricity rates year-round in return for setting a higher rate on specific summer afternoons. The rate is three to five times higher than the regular rate on up to fifteen "critical peak" afternoons during the summer with customers notified of CPP days on a day-ahead basis. It is also the default rate for large commercial and industrial customers of SCE. For new program entrants, a bill protection option is available that prevents participants from paying more than they would have under their previous rate during the first year of CPP participation. Participants may also opt for technical assistance to help them better take advantage of the program. SDG&E customers participating in the Day-Ahead option of the Capacity Bidding Program are not eligible for CPP.

Peak Day Pricing (PDP), very similar to SCE's and SDG&E's Critical Peak Pricing (see above), is the default rate for PG&E's large commercial, industrial and agricultural customers. Small and medium business customers (demand 200 kW and less) will automatically transition to PDP beginning November, 2014. PDP is a "time varying" pricing plan with additional charges added during critical peak times (2-6 p.m. on 9 to 15 "Peak Event Days" per year, with some alternative durations available). Participants shield their exposure to high prices during PDP events by shedding load during the peak price hours. Customers on E-19 and E-20 rate schedules (demand of 500-999 kW and 1000+ kW respectively) have the option to mitigate bill fluctuation by allotting a portion of their load to a "capacity reservation."

The ***Demand Bidding Program (DBP)*** offered by PG&E and SCE provides incentive payments of up to $0.50/kWh for curtailment commitments. Participants place bids online the day before a peak event for the amount of power they are willing to reduce (minimum 10 kW each hour), in increments of two hours or more. DBP events usually take place from noon to 8:00 p.m. and can occur on any weekday excluding holidays. There is no penalty for failure to reduce electric load during an event.

PG&E and SCE offer the ***Optional Binding Mandatory Curtailment Program***, which provides customers with exemptions from rotating power outages if they can reduce their circuit load during Stage 3 emergencies. Participants must reduce their power consumption by 15% below their established baseline load for the duration of every rotating outage event. The penalty for failure to reduce as requested is $6.00 per kWh for energy use that exceeds an established baseline.

SCE's ***Summer Discount Plan and SDG&E's Summer Saver program*** offer summer air conditioner cycling programs to commercial customers These programs provide a credit on participants' summer season electric bills in return for allowing the utility to cycle air conditioners when needed during the months of May to September. Customers can choose among several options regarding the frequency and duration of curtailments, each with corresponding remuneration levels.

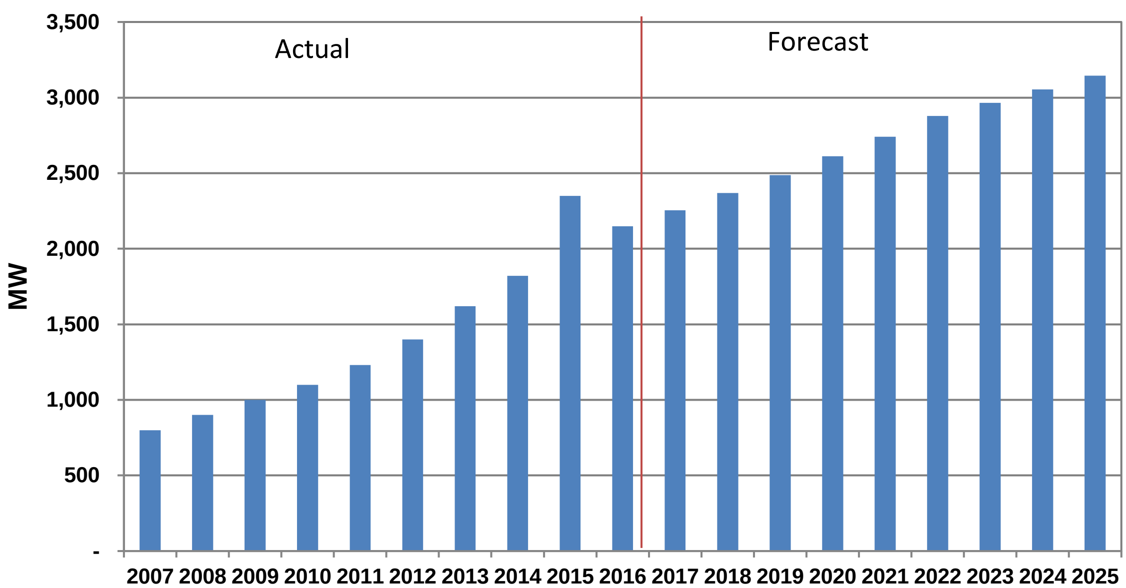
SCE offers the ***Scheduled Load Reduction Program (SLRP)*** to qualified bundled-service customers whose average monthly demand is 100 kW or more. The program provides a $0.10 per kWh on-bill credit for reducing load on prescheduled days and times on weekdays from June 1 through September 30.

PG&E and SCE offer financial incentives for implementing technologies that permanently shift electric load by storing thermal cooling capacity during off-peak hours (e.g., by chilling water or making ice) in order to meet cooling load during subsequent peak hours.

A.4 Texas (ERCOT)

Federal customers can receive payments for providing load curtailments through several programs offered by the Electric Reliability Council of Texas (ERCOT). DR participation in ERCOT territory can be split broadly into economic and emergency DR. Through the economic DR program, customers bid DR into the energy market and are paid a utilization payment. Since ERCOT is not a FERC jurisdiction they are not required to pay the full LMP. ERCOT provides payment of LMP-G for DR resources which are cleared in the energy market. These resources are not paid an availability payment for participation in the energy market but may also participate in one of the emergency DR programs through which they would receive availability payments.

Figure 4: ERCOT Historical and Projected DR volume



Source: ERCOT and Navigant. Combination of LR and ERS programs

Table 6: ERS & Energy Market DR summary ERCOT

Category	ERS	Energy Market DR
Program Period	Annual, broken into three 4-month offer periods	Annual (bid at will)
Event Windows	Broken into 6 weekly and daily bidding windows	Based on bidding and clearing
Dispatch Limits	None	Based on bidding and clearing

Notification Time	Can choose 10 or 30 minutes	Real-Time: Resources with bids at marginal LMP must be capable of moving load incrementally in either direction every five minutes, based on dispatch instructions
Curtailment Limits	12 hours per 4-month contract period	Based on bidding and clearing
Tests	1 per year	N/A
Enrollment Deadlines	30 days prior to start of contract period	Daily bidding
Payments	Monthly	Monthly
Minimum Size	100 kW	1 MW
Metering Requirements	15-minute interval meter	15-minute interval meter
Baselines	Choose between several options: Regression, High 8 of 10, Matching Day, Weather-Sensitive	Compare telemetered load to basepoint instructions

Sources: Navigant Research

Load Resource Participation[26] : Customers who can change their load in response to an instruction and can meet certain performance requirements may qualify to become Load Resources (LRs). Qualified LRs may participate in ERCOT's real-time energy market (Security-Constrained Economic Dispatch, or SCED) and/or may provide operating reserves in the ERCOT ancillary services (AS) markets. In the ERCOT markets, the value of a Load Resource's load reduction is equal to that of an increase in generation by a generating plant. Load Resources in SCED submit bids to buy power "up to" their specified level, and are instructed by ERCOT to reduce Load if wholesale market prices equal or exceed that level. Load Resources that are scheduled or selected in the ERCOT Day-Ahead AS Markets are eligible to receive a capacity payment regardless of whether they are curtailed.

Voluntary Load Response: A customer may decide independently to reduce consumption from its scheduled or anticipated level in response to price signals or high demand on the ERCOT system. This is known as Voluntary Load Response[27].
Depending on how the retail contract with their Load Serving Entity (LSE) is structured, these customers may have the opportunity to benefit financially during periods when wholesale market prices are high.

[26] http://www.ercot.com/services/programs/load/laar
[27] http://www.ercot.com/services/programs/load/vlrp

Emergency Response Service (ERS): As with the Load Resource program, customers bid to provide load reductions. However, this program is aimed solely at alleviating emergency (as opposed to high price) conditions on the ERCOT grid. ERCOT procures ERS three times annually for four-month Standard Contract Terms (SCT). In each SCT, ERCOT procures ERS per two different response times—thirty minutes and ten minutes[28].

For all programs, the customer participates through its Retail Electricity Provider (REP), and transactions with ERCOT are conducted by the qualified scheduling entity (QSE) for the customer's REP. The specific terms for customer participation, including compensation, are based on the contractual arrangement between the customer and their REP.

Table 7: DR Participation in ERCOT ERS

Year	MW
2017	890
2018	935
2019	982
2020	1,031
2021	1,082

Sources: ERCOT website; DR forecasts are Navigant estimates

A.5 France

France has a mature market which allows DR to participate in all markets (day-ahead, intraday, balancing, ancillary services, reserves and capacity). This has been achieved by allowing aggregators to operate independently of suppliers. Prequalification of all products participating in the markets is completed by the TSO to validate the capacity. These prequalification test are designed by the RTE and are different for each product depending on the service required. The NEBEF Mechanism is most closely aligned to the IESO DR auction since it involves bidding DR into the wholesale market. Participation in the NEBEF mechanism provides only utilization payments (no availability payments). DR resources are paid the spot price when they are activated. Participation was high in 2016 due to high wholesale prices.

NEBEF Mechanism (Day-Ahead and Intraday markets)*:* The NEBEF mechanism allows DR to bid directly into the wholesale market as energy. This mechanism has been in place since 2013 for the day-ahead and January 2017 for the Intraday markets. The volume of DR activated through the Day-Ahead market was low to begin (310 MWh in 2014), partially due to a mild winter. Since then the participation has been 1.522 GWh (2015) and 10.313 GWh (2016)[29]. Offers through the NEBEF mechanism were intensive at the end of 2016 due to high wholesale prices. To participate in the NEBEF mechanism, the DR provider is required to sign a contract with the TSO. The minimum size of DR bids must be 0.1 MW. Activation of DR through the wholesale market is managed by the TSO based on the system requirements. The DR is bid directly into the EPEX Spot market and DR are paid the spot price when they are activated.

[28] http://www.ercot.com/services/programs/load/eils

[29] http://www.smartenergydemand.eu/wp-content/uploads/2017/04/SEDC-Explicit-Demand-Response-in-Europe-Mapping-the-Markets-2017.pdf

Balancing, Ancillary Services and Reserves: Two ancillary service markets (The Frequency Containment Reserve (FCR) and the Automatic Frequency Restoration Reserves (aFRR)) are open to DR participation. Historically, bids into the ancillary service markets and balancing programs needed to include only DR or only generation. Beginning in January 2017, aggregated DR and generation was allowed to bid experimentally into the FCR. Contracts for FCR and aFRR total 600-700 MW capacity each. Both the FCR and aFRR have minimum bid sizes of 1 MW, are activated automatically, receive very short notification times (<400 s) and can be triggered an unlimited number of times. FCR and aFRR are paid availability payments based on their contracts and when activated are paid the spot price in the market. In cases where the DR is not available, penalties are based on the spot price rather than the availability payments.

Two Balancing Mechanism markets manual Frequency Restoration Reserve (mFRR) and Replacement Reserves (RR) are open to DR participation in France. A maximum of 1000 MW is contracted for mFRR and a maximum of 500 MW is contracted for RR. The participation in 2016 was 480 MW. The mFRR and RR have minimum bid sizes of 10 MW, are activated manually, receive short notification times (<30 min) and can be triggered an unlimited number of times. The TSO activates bids based on the most economic offer. DR therefore competes against generation. The mFRR and RR are paid both an availability payment and when activated an energy payment based on their bid. In cases where the DR is not available, penalties are based on the spot price rather than the availability payments.

Capacity Mechanism*:* The capacity mechanism was launched in January of 2017 in response to growing concerns about security of supply[30]. The capacity mechanism is a decentralized market which does not interfere with the energy market. Capacity certificates are traded apart from the energy market and owning a capacity certificate does not give any rights to the corresponding energy. All capacity owners in France have an obligation to commit on their availability during peak periods 3 years in advance. All suppliers must own capacity certificates which correspond to the consumption of their customers during the peak periods. In its first year, the capacity market included 1700 MW of certified exchangeable capacities and 800 MW of capacity obligation reduction from retailers. The capacity will reflect only the availability of DR in the market. Its effective activation will be counted through the balancing mechanism or wholesale market[29].

A.6 Finland

In Finland, DR can participate in all markets (day-ahead, intraday, balancing, ancillary services, reserves and capacity) however Finland is able to source a significant amount of their capacity needs from neighboring countries which may be limiting actual DR participation in the markets. Participation in the Economic DR is most closely aligned to the IESO DR auction. DR resources are paid only a utilization payment (spot price) for participating. No availability payments are provided.

Economic DR (Day-Ahead and Intraday Markets)*:* Operating on the Elspot (day-ahead) and Elbas (intraday) markets requires an agreement with Nord Pool, as well as an agreement with an open electricity provider, which also covers balance responsibility. Historic participation in the day-ahead market has been between 200-600 MW and participation in the intraday market has been between 0-200 MW. The day-ahead and intraday markets both require a minimum demand resource size of 0.1 MW to participate. DR participating in the wholesale markets is paid the spot price for energy. In the wholesale

[30] http://www.ceem-dauphine.org/assets/dropbox/DGEC-_Etienne_Hubert.pdf

markets, penalties are based on the imbalance settlement price which corresponds to the Nordic balancing market price.

Ancillary and Balancing Services*:* Finland allows participation of DR in all ancillary services through Fingrid. A summary of the services, contract types, minimum size requirements, activation time and payments is provided below[31].

Summer	#Resources and Registered MW	Events	Avg. Hourly Response	Energy Payments	Avg. payment per MWh	Payment Type
Frequency controlled normal operation reserve (FCR-N)	Yearly and hourly markets	0.1 MW	1 MW	Automatic - 3 minutes	Constantly	Yearly market + Price of electricity
Frequency controlled disturbance reserve (FCR-D)	Yearly and hourly markets	1 MW	240 MW	Automatic 5 s / 50% 30 s / 100%, when f under 49,9 Hz OR 30 s, when f under 49,7 Hz and 5 s, when f under 49,5 Hz	Several times per day	Yearly Market
Frequency controlled disturbance reserve (on-off-model) (FCR-D)	Long-term contract	10 MW	240 MW	Automatic Instantly, when f under 49,5 Hz	About once a year	Availability + Activation Fee
Automatic Frequency Restoration Reserves (FRR-A)	Hourly market	5 MW	0 MW	Automatic Must begin within 30 s of the signal's reception, must be fully activated in 2 minutes	Several times a day	Hourly market + energy price
Balancing power market	Hourly market	10 MW	100-300 MW	15 minutes	According to the bids, several times per day	Market price

31 http://www.fingrid.fi/en/electricity-market/Demand-Side_Management/Market_places/Pages/default.aspx

Summer	#Resources and Registered MW	Events	Avg. Hourly Response	Energy Payments	Avg. payment per MWh	Payment Type
Fast disturbance reserve	Long-term contract	10 MW		15 minutes	About once a year	Availability + Activation Fee

A.7 Australia

Australia has enabled DR participation in the wholesale market however third parties (aggregators) are not allowed to bid in. When participating in the wholesale market, resources are paid a utilization payment only (electricity spot price). Participation directly in the wholesale market has not been very high however retailers who cover the majority of the electricity consumption use DR as a tool to manage their costs.

The energy market has already developed innovative solutions to facilitate consumers' DR, reflecting the absence of any barriers to demand side participation. Retailers have at least 235 MW of DR capacity under contract, and demand side management providers are managing at least 310 MW of DR capacity. Other estimates suggest 2000 MW of DR capacity that is available to respond to wholesale market prices.[32]

DR Mechanism (DRM)*:* Australia investigated implementing a DRM which would unbundle the provision of energy from the provision of ancillary services. The proposal was to allow DR to be settled through the wholesale market by third parties however the mechanism was determined to be unnecessary in the market today. The review determined that the benefits of the regulatory mechanism can be achieved under existing conditions. Market and technology developments mean that large customers, retailers, DSM providers and businesses can already negotiate commercial arrangements with one another leading to a competitive DR market.

Ancillary Services*:* As of July 2017, DR will have access to ancillary services markets. Currently the following Ancillary service products are available: Regulating, Fast, Slow, Delayed[33]. *Payment:* Ancillary services are procured daily at the spot price on the Ancillary services market.

The Ancillary Services Unbundling changes will enable third parties to register and sell Frequency Control Ancillary Service (FCAS) using aggregated loads independently of the retailer. This means that at the commencement of the DRM, the DRAs will be able to offer DR as FCAS if it satisfies the NEM's technical requirements. The existing technical and procedure requirements will apply to the DRAs.
Any load offered by a DRA as ancillary service cannot simultaneously be offered as DRM load for a DR interval and the DRM process has no involvement in the settlement of that DRA or load in providing FCAS.

When required, Australia goes through a tender process to acquire DR as a capacity resource. Resources provide bids which include three payments, an availability fee, a pre-activation fee and an energy payment. If selected the resources are paid the availability fee and then if activated are paid the pre-activation and energy payment.

[32] http://www.aemc.gov.au/Rule-Changes/Demand-Response-Mechanism/Draft/AEMC-Documents/Draft-Determination.aspx

[33] http://www.brattle.com/system/publications/pdfs/000/005/220/original/AEMC_Report.pdf?1448478639

A.8 South Korea

In April 2014, legislation was passed in South Korea allowing DR to participate in its wholesale capacity market. DR resources which previously were under contract bid into the DR auction when it opened in 2014. These resources receive availability payments. They then bid into the energy market and receive the system marginal price for energy when activated.

South Korea has a system peak of about 80GW, more than 80% of which is from commercial and industrial energy users. With electricity consumption growing at a rapid rate and a reliance on fuel imports to meet nearly 100% of its needs, South Korea is actively promoting DR to help ensure reliability, encourage competition, and develop an ecosystem of IT-based energy businesses. The enablement of DR is one of the requirements of South Korea's 'Creative Economy' initiative, which in the energy sector is broadly revolved around measures to deal with domestic energy demands and to respond to global climate change[34].

Table 8: DR Summary South Korea

Category	Capacity DR	Energy DR
Program Period	Bidding (Twice / year)	Day Ahead bidding
Notification Time	1 hour ahead	Day Ahead
Payment	Capacity* + Variable cost of Marginal Gen	SMP** (System Marginal Price)

**Capacity payment in first 6 months of 2017: 19,894.7 won/kw*
***Average SMP in first 6 months of 2017: 84.36 won/kwh*
Source: Interview with Korea Electrotechnology research institute

The DR (DR) market was introduced in the Korean electricity market in November 2014. In the past, demand management was implemented through the program by Korea Electric Power Corporation (KEPCO) in Korea. However, after the DR market was opened, a third party called "the load aggregator" was allowed to participate in the Korean electricity market. Load aggregators have recruited the resources of KEPCO's customers who have participated in demand management.
DR resources (DRR) have been traded in the Korean wholesale electricity market since November 2014. Customers can join the DR market only through a load aggregator. There are 17 load aggregators registered in the electricity market as of June 2017. In the DRR market, peak curtailment DRRs (or capacity DRRs) and price responsive DRRs are traded separately.

In the case of ***capacity DRRs (peak curtailment)***, Korea Power Exchange (KPX) (Independent System Operator in Korea Electricity Market) instructs a load curtailment an hour ahead, and these resources assume a role to substitute for high-cost generators. The customers participating in the load curtailment are compensated with incentives such as ***payments for availability and performance***[35].

The payment for availability is calculated in the same method as the capacity price of generators and the payment for performance is determined based on the resources' actual curtailment and the highest variable generation cost at that time.

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[34] https://www.engerati.com/article/demand-response-comes-south-korea

[35] DR Resource Allocation Method Using Mean-Variance Portfolio Theory for Load Aggregators in the Korean DR Market; Jaeyong Chae and Sung-Kwan Joo; June 2017

In the case of ***Energy DRR (price responsive)***, the resources bid on the day-ahead electricity market and curtail the load if the demand reduction price is lower than the bid prices of generators, and are compensated with incentives based on the system marginal price (SMP).

At this point DR does not seem to participate in the Ancillary services market in South Korea[36].
The Korea Power Exchange (KPX), the transmission grid operator for South Korea, implemented its Smart DR program several years ago. This program was an all-automated DR approach for commercial and industrial (C&I) customers. KPX also pursued 500 MW of wholesale market DR participation with its Smart DR initiative. It achieved this through capacity auctions and other market-based mechanisms similar to the constructs in the U.S. RTO markets (e.g., PJM and ISO-NE). These programs were funded by the government, separate from the competitive electricity market.

The DR program starts with seasonal procurements of DR resources. DR may bid into the day-ahead energy market within the committed load reduction, and then it is obliged to reduce up to the committed load reduction when KPX orders a load reduction in real-time. The KPX DR program is intended to encourage DR aggregators to participate in the market, and utilities such as the Korea Electric Power Corporation are not allowed to participate.

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[36] http://www.globalsmartgridfederation.org/wp-content/uploads/2016/12/flexibilitylow.pdf

APPENDIX B. FERC 745 RULING

The details of the FERC 745 ruling are included in this appendix. Under the law, FERC has jurisdiction over wholesale electricity markets, which reach across state lines, but states have legal authority over their individual retail markets. The Electric Power Supply Association (EPSA), the national trade association for competitive power suppliers, argued that Order 745 crossed over too much into these retail markets, constituting an overreach of federal authority[37]. The Supreme Court disagreed with EPSA. In a 6-2 decision with Justice Samuel Alito recusing himself, the nation's highest judicial body ruled that FERC acted within its powers enumerated under the Federal Power Act (FPA) in issuing the order, which aims to ensure that DR providers are compensated at the same rates as generation owners. Many of the ISOs and econometricians oppose the ruling.

B.1 Federal Regulatory Energy Commission ("The Commission") Final Rule

In their original ruling[38], FERC argued that providing LMP as compensation to 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.

The Commission argued that when a demand response resource has the capability to balance supply and demand as an alternative to a generation resource, and when dispatching and paying LMP to that demand response resource is shown to be cost-effective as determined by the net benefits, payment by an RTO or ISO of compensation other than the LMP is unjust and unreasonable. When these conditions are met, we find that payment of LMP to these resources will result in just and reasonable rates for ratepayers.

FERC indicated that they believe paying demand response resources the LMP will compensate those resources in a manner that reflects the marginal value of the resource to each RTO and ISO.

The Commission emphasized that these findings reflect a recognition that it is appropriate to require compensation at the LMP for the service provided by demand response resources participating in the organized wholesale energy markets only when two conditions are met:

- The first condition is that the demand response resource has the capability to provide the service, i.e., the demand response resource must be able to displace a generation resource in a manner that serves the RTO or ISO in balancing supply and demand.
- The second condition is that the payment of LMP for the provision of the service by the demand response resource must be cost-effective, as determined by the net benefits test described herein.

Rather than requiring compensation at LMP in all hours, the Commission requires the use of the net benefits test described herein to ensure that the overall benefit of the reduced LMP that results from dispatching demand response resources exceeds the cost of dispatching those resources. When the above-noted conditions of capability and of cost-effectiveness are met, it follows that demand response resources that clear in the day-ahead and real-time energy markets should receive the LMP for services provided, as do generation resources. LMP represents the marginal value of an increase in supply or a

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[37] https://www.utilitydive.com/news/updated-supreme-court-upholds-ferc-order-745-affirming-federal-role-in-de/412668/

[38] https://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf

reduction in consumption at each node within an ISO or RTO, i.e., LMP reflects the marginal value of the last unit of resources necessary to balance supply and demand.

Barriers to demand response participation at the wholesale level identified by commenters include the lack of a direct connection between wholesale and retail prices, lack of dynamic retail prices (retail prices that vary with changes in marginal wholesale costs), the lack of real-time information sharing, and the lack of market incentives to invest in enabling technologies that would allow electric customers and aggregators of retail customers to see and respond to changes in marginal costs of providing electric service as those costs change. The Commission concludes that paying LMP can address the identified barriers to potential demand response providers.

Removing barriers to demand response will lead to increased levels of investment in and thereby participation of demand response resources (and help limit potential generator market power), moving prices closer to the levels that would result if all demand could respond to the marginal cost of energy. To that end, the Commission emphasizes that removing barriers to demand response participation is not the same as giving preferential treatment to demand response providers; rather, it facilitates greater competition, with the markets themselves determining the appropriate mix of resources, which may include both generation and demand response, needed by the RTO and ISO to balance supply and demand based on relative bids in the energy markets.

The Commission disagrees with commenters who contend that demand response resources should be paid LMP-G in all hours. First, as discussed above, demand response resources participating in the organized wholesale energy markets can be cost effective, as determined by the net benefits test described herein, for balancing supply and demand and, in those circumstances, it follows that the demand response resource should also receive compensation at LMP. Second, such comments largely rely on arguments about economic efficiency, analogizing to incentives for individual generators to bid their marginal cost. These arguments fail to acknowledge the market imperfections caused by the existing barriers to demand response, also discussed above. In Order No. 719, the Commission found that allowing demand response to bid into organized wholesale energy markets "expands the amount of resources available to the market, increases competition, helps reduce prices to consumers and enhances reliability."

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," notwithstanding the particular costs of production of individual resources.

Some arguments advocating paying LMP-G rather than LMP assume that demand response resources need to purchase the energy in day-ahead markets or by other means and then "resell" the energy to the market in the form of demand response. However, The Commission does not view demand response as a resale of energy back into the energy market. Instead, as the Commission also explained in EnergyConnect and in Order No. 719-A, the Commission asserts jurisdiction with respect to demand response in organized wholesale energy markets because of the effect of demand response and related RTO and ISO market rules on Commission-jurisdictional rates.

B.2 LMP-G Arguments

Many econometricians have argued that Demand Response resources should be compensated LMP-G rather than LMP[39].

They argue that "the customer has an option to purchase electricity to satisfy demand with the strike price in the option set at the retail price: if you exercise the option and consume you pay the retail price, but if you don't exercise the option, and don't consume, you don't pay the retail price. As always with other options, the market value of the option is the difference between the market price of the product and the strike price of the option. Think of the analogy to stock options. If the stock market price is $50 and you have an option to buy the stock at $30, then the value of the option is $20. In the parlance of the Order 745 discussion, the strike price is treated as "G" and the market value of the demand response is "LMP-G."

They have also indicated that paying LMP may introduce a double payment problem. They indicate that "there are many examples of perverse incentives created by the demand response compensation at LMP. For instance, distributed generation built just before the customer meter would be worth much less than the same plant built just after the customer meter. Even setting aside the (related) perverse incentives of retail net-metering, you should build you next generator on the customer side of the meter; you could use the generator output without changing your actual consumption; you would not be seen as buying from the grid so you would save the LMP; and you would be credited for a "negawatt" and be paid the LMP again!"

They also indicate that "the money to pay for demand response has to come from somewhere, and it comes precisely from the wholesale generators as a group (this is the point of the net benefits test). Demand response will reduce short-term energy market prices, allowing the mandate to collect the extra demand response costs from the remaining loads without increasing the apparent average short term price to those loads. Hence, we see the rule operating as a regulation to further induce supply-side price suppression."

B.3 Additional Resources

The following articles provide a number of views related to the FERC 745 ruling.

https://www.greentechmedia.com/articles/read/supreme-court-rules-in-favor-of-demand-response#gs.6AN95=g
https://www.utilitydive.com/news/updated-supreme-court-upholds-ferc-order-745-affirming-federal-role-in-de/412668/
http://www.scotusblog.com/2016/01/opinion-analysis-court-blesses-lower-wholesale-power-rates/
https://www.forbes.com/sites/peterdetwiler/2016/01/25/scotus-finds-strongly-in-favor-of-demand-response/#63cc9516408d
https://sites.hks.harvard.edu/fs/whogan/Hogan_DR_pricing_021516.pdf

[39] https://sites.hks.harvard.edu/fs/whogan/Hogan_DR_pricing_021516.pdf

TAB 9

EB-2019-0242

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

AND IN THE MATTER OF an Application by the Association of Major Power Consumers in Ontario, pursuant to section 33 of the *Electricity Act, 1998, S*.O. 1998, c. 15, Sched. A and Rule 17 of the Ontario Energy Board *Rules of Practice and Procedure* for review of amendments to the Independent Electricity System Operator market rules related to the implementation of a Transitional Capacity Auction (MR- 00439-R00-R05).

AND IN THE MATTER OF a notice of motion by the Association of Major Power Consumers in Ontario, pursuant to section 33 of the *Electricity Act, 1998, S*.O. 1998, c. 15, Sched. A and Rule 17 of the Ontario Energy Board *Rules of Practice and Procedure* to stay the operation of amendments to the Independent Electricity System Operator market rules pending determination of the Application.

AFFIDAVIT OF
Brian Rivard, Adjunct Professor at the Ivey Business School and
Research Director of the Energy Policy and Management Centre, Western University

November 8, 2019
Revised: November 21, 2019

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N.	Exhibit "N"	Paper by David Brown and David Sappinton published in the Journal of Regulatory Economics in 2016

TAB 1

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I, Brian Rivard, of the Town of Paris, in the Province of Ontario, MAKE OATH AND SAY AS FOLLOWS:

A. INTRODUCTION

A.1 Q: Please state your name and occupation.

1. My name is Brian Rivard. I am Adjunct Professor at the Ivey Business School at Western University and the Research Director of the school's Energy Policy and Management Centre.

A.2 Q: For whom are you testifying in this proceeding?

2. I am testifying on behalf of Kingston CoGen Limited Partnership ("KCLP"). Attached hereto as **Exhibit "A"** is a signed copy of Form A pursuant to the Ontario Energy Board's (the "Board") Rules of Practice and Procedure.

A.3 Q: What is your educational background?

3. I hold a Ph.D. and M.A. in Economics from Western University. My field of specialization is industrial organization with an emphasis on the study of competitive markets, economic efficiency, and regulatory economics. I also have a B.A. in Economics from the University of Windsor.

A.4 Q: What is your professional background?

4. A copy of my curriculum vitae is attached hereto as **Exhibit "B"**. I began my career working as an Economist and then as a Senior Economist at the Canadian Competition Bureau. The Competition Bureau is the agency responsible for enforcing the Canadian *Competition Act* and protecting the Canadian economy against anti-competitive business conduct such as collusion or price fixing, abuse of dominant position, and anti-competitive mergers. My primary function as an Economist at the Competition Bureau was to conduct economic analysis in support of the Bureau's various enforcement actions.

5. After briefly working as a Senior Economic Consultant for the economic consulting firm, LECG, I joined the Independent Electricity System Operator ("IESO") (then called the Independent Electricity Market Operator) in 2000 as a Senior Economic Advisor in the Market Assessment and Compliance Division, reporting to the Market Surveillance Panel. Within this role, I was responsible for monitoring the Ontario electricity market for anomalous conduct, including abuses of market power or gaming, and for structural or market design deficiencies.

6. In 2006, I was promoted to Manager of Economics with the responsibility of conducting analysis of the effects of changes in wholesale electricity market design or government policy on the efficient operation of the IESO's wholesale market.

7. In 2010, I assumed the role of Manager of Regulatory Affairs and Sector Policy Analysis. In this role, I represented the IESO on the ISO-RTO Council ("IRC") as a member and Chair of the IRC's Market Committee. The IRC is a member group of North America's competitive wholesale market operators.[1] I was the Chair of the Market Committee at the time the United States Federal Energy Regulatory Commission (the "Commission") issued its Final Rule in Docket No. RM10-17-000, Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets* ("FERC Order No. 745").[2]

8. In 2013, I was appointed the position of Director of Markets. As Director of Markets, I was responsible for evolving the design of the Ontario electricity market to ensure it operated fairly and efficiently. As Director, I oversaw the transition of the responsibility for administering demand response programs from the Ontario Power Authority

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[1] In addition to the IESO, the IRC includes the Alberta Electric System Operator ("AESO"), the California Independent System Operator Corporation ("CAISO"), the Electric Reliability Council of Texas, Inc., ("ERCOT"), ISO New England, Inc., ("ISO-NE"), the Midcontinent Independent System Operator, Inc. ("MISO"), the New York Independent System Operator, Inc. ("NYISO"), PJM Interconnection, L.L.C., ("PJM") and the Southwest Power Pool ("SPP").

[2] Being Tab 8 to the IESO's Book of Authorities in Response to AMPCO's Request for a Stay, dated November 5, 2019, available online at: http://www.rds.oeb.ca/HPECMWebDrawer/Record/657752/File/document [FERC Order No. 745].

("OPA") to the IESO. I initiated the design and implementation of the IESO Demand Response Auction ("DRA").

9. In 2015, I left the IESO to join Charles River Associates International as a Principal in their Energy Practice. I advised clients on a variety of issues, most notably competitive wholesale market design, market power and market manipulation issues.

A.5 Q: What is your current position?

10. I am Adjunct Professor and Research Director of the Energy Policy and Management Centre for the Ivey Business School at Western University. My primary role at Ivey is to further the mission of the Energy Centre which is to:

    a. Contribute to energy policy-making through the production and dissemination of evidence-based research and analysis on major policy issues affecting the electricity, gas, oil and pipeline sectors in Canada;

    b. Provide a transparent and reliable forum for industry, government, academia, and interested stakeholders to discuss and exchange ideas on energy sector development and policy; and

    c. Educate students, executives, and government officials on national and global energy sector issues.

A.6 Q: What other professional experiences do you have?

11. I serve as a peer reviewer for the Energy Journal. I am a Member of the International Association of Energy Economists. I am an occasional lecturer at Ryerson University and Osgoode Hall Law School.

A.7 Q: Have you previously submitted testimony before Board or other regulatory agencies?

12. I provided oral testimony before the Board on behalf of the IESO in EB-2007-0040 (regarding the 3x Ramp Rate). I provided written and oral testimony before the

Commission on behalf of Shell Energy North America (US), L.P. in Docket No. EL02-71-057.

A.8 Q: What is the purpose of your testimony in this proceeding?

13. I was retained by counsel for KCLP to review the Association of Major Power Consumers of Ontario's ("AMPCO") Notice of Appeal (the "Appeal") to Market Rule Amendments MR-00439-R00-R05 (the "Amendments") and supporting evidence, and to offer my independent views on the economic merit of AMPCO's position in this proceeding.

14. The Amendments enable the evolution of the IESO's DRA into a Transitional Capacity Auction ("TCA") that will allow non-contracted and non-regulated generators ("non-committed dispatchable generators") to participate in future capacity auctions alongside Demand Response ("DR") resources.

15. The focus of the Appeal is the appropriate level of compensation for DR resources. The IESO provides non-committed dispatchable generators an energy payment if / when the generators respond to an IESO instruction to produce energy based upon their offered price. Under the Amendment, DR resources will not receive an energy payment (or "utilization payment") when DR resources respond to an IESO instruction to reduce their energy consumption (an "economic activation").[3] AMPCO claims that this

[3] Application for Review of an Amendment to the Independent Electricity System Operator Market Rules, Notice of Appeal, EB-2019-0242, filed September 26, 2019, available online at: http://www.rds.oeb.ca/HPECMWebDrawer/Record/653723/File/document, at para. 12. The terms "energy payment" and "utilization payment" are used interchangeably in the proceeding material. For clarity, a ***utilization payment*** is a payment made to a demand response market participant that responds to an instruction from the system operator (IESO) to reduce the amount of electricity (energy) that they are consuming. The instruction from the IESO to a demand response resource to reduce energy consumption is referred to as an ***energy activation***. For this reason, utilization payments are sometimes referred to as ***activation payments***. Utilization payments at the wholesale market-clearing price are called ***energy payments***. A DR resource could receive an energy activation instruction from the IESO as part of the IESO's economic dispatch process, called an ***economic activation***, as a test of the DR resources capability, or for reliability or emergency reasons. The issue in the Appeal is compensation for economic activation. The IESO plans to compensate DR resources if the IESO instructs the resource to reduce consumption to test the resources capability or for reliability and emergency reasons.

represents inequitable and unfair treatment of DR resources, places DR resources at a competitive disadvantage to non-committed dispatchable generators in the TCA, and results in a TCA that is unfair and inefficient, and effectively anticompetitive and discriminatory. AMPCO also contends that the Commission, in FERC Order No. 745, has definitively recognized "that failure to compensate DR resources for such services is unjust and unreasonable."[4]

16. Counsel further asked that I address the issue the Board raised in Procedural Order No. 2. The Board stated that "it is particularly interested in receiving evidence that describes the experience with compensation for DR in markets in other relevant jurisdictions, and the extent to which that experience is informative in the context of the Amendments having regard to any pertinent differences such as differences in market design or structure."

17. Specifically, my evidence will:

a. analyze the economic merit of AMPCO's assertions of inequitable and unfair treatment, competitive disadvantage, and the negative impacts on competition and efficiency; and

b. identify pertinent similarities or differences between the United States wholesale markets and the Ontario market, such as differences in market design or structure, to inform the Board of the applicability of FERC Order No. 745 to Ontario and in the context of the Amendments.

A.9 Q: How is your testimony organized?

18. The remainder of my testimony consists of three parts. In Part B, I offer my analysis of the economic merit of AMPCO's assertions. In Part C, I summarize the conclusions of FERC Order No. 745 and identify unique aspects of the Ontario market that should

[4] *Ibid* at para. 36.

inform a conclusion on the applicability of the Order to Ontario. In Part D, I provide my summary conclusions.

A.10 Q: What are your conclusions?

19. In my opinion, the Amendments provide an equitable treatment of TCA participants. I give evidence that demonstrates the Amendments afford fair and equitable treatment to TCA participants, do not place DR resources at a competitive disadvantage to non-committed dispatchable generators, and promote fair and efficient competition to the benefit of Ontario consumers. I further conclude that the application of FERC Order No. 745 in Ontario will not achieve the effects the Commission intended when it issued its decision. This is due to several unique aspects of the Ontario electricity market, each of which I will speak to herein.

B. AMPCO'S ASSERTIONS ARE VOID OF FACTUAL SUPPORT AND LACK ECOMOMIC MERIT

B.1 Q: What is your understanding of the basis of AMPCO's appeal?

20. The basis of AMPCO's appeal is that generators receive a payment for energy services provided (economic activations) but DR resources do not. AMPCO asserts that this represents "an inequity in treatment between generation resources and DR resources."[5] AMPCO further asserts that this unequitable treatment puts "DR resources at a competitive disadvantage to generators"[6] in the TCA and would allow generators to "effectively and unfairly displace"[7] DR resources in the TCA. AMPCO concludes that this would "undermine competition"[8] and is "inimical to the IESO's own objective of

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[5] *Ibid* at para. 4.

[6] *Ibid* at para. 22.

[7] *Ibid* at para. 4.

[8] *Ibid* at para. 14.

enhancing competition for the benefit of consumers."[9] The failure to compensate DR resources for economic activations "would result in a capacity market that is unfair and inefficient, and effectively anticompetitive and discriminatory."[10]

B.2 Q: What evidence has AMPCO provided to establish competitive disadvantage?

21. AMPCO's assertion of competitive disadvantage is articulated in the Affidavit of Mr. Colin Anderson at paragraphs 12 through 19. Mr. Anderson reasons as follows:

a. In the existing DRA, the only revenue stream available to participants is a capacity payment (called an availability payment). There are currently no payments made for energy activations. If the TCA proceeds in December 2019, non-committed dispatchable generators will qualify for an availability payment and an energy payment when economically activated. DR resources will still only qualify for an availability payment.[11]

b. Non-committed dispatchable generators will be able to submit a capacity offer into the TCA taking into account their anticipated energy payments. They will be able to set a capacity offer price that is lower by the amount of their anticipated energy payments. DR resources will not have the same opportunity.[12]

c. DR resources incur "legitimate costs" when they are economically activated to curtail demand. If they do not receive an energy payment, they will not be able to recover these costs.[13]

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[9] *Ibid* at para. 25.

[10] *Ibid* at para. 45.

[11] Affidavit of Colin Anderson, sworn October 11, 2019, available online at: http://www.rds.oeb.ca/HPECMWebDrawer/Record/655144/File/document, at para. 12.

[12] *Ibid* at para. 14

[13] *Ibid* at para. 19.

d. DR resources will have two options on how to deal with this. First, they can include the anticipated cost of activation in their capacity offer price. This would put DR resources at a competitive disadvantage to non-committed dispatchable generators that do not have to include these costs in their capacity offer price. Second, they could omit including the anticipated cost of activation in their capacity offer price, but then risk not recovering these costs when economically activated.[14]

B.3 Q: If a market participant cannot recover legitimate cost in the market does that not place it at a competitive disadvantage to others that can recover their cost?

22. From an economic perspective, if a DR resource incurs a cost when economically activated to curtail demand that it would ***avoid*** if it continued to consume, then it could be competitively disadvantaged by the Amendments. However, AMPCO has provided no factual evidence or even conceptual evidence that explains the nature, magnitude or legitimacy of these ***avoidable*** costs.

23. By contrast, a natural gas fired generator could provide both conceptual and factual evidence that it incurs a fuel cost when economically activated in order to produce energy that it can avoid (save) by not producing. This evidence is readily and publicly available, and is the basis for the energy payments made to these generators.

B.4 Q: Why does it make economic sense to pay a generator an energy payment for economic activation?

24. In order to induce a generator to produce energy, it must receive a payment that allows it to recover its avoidable cost of activation. If it did not receive a payment, it would be in its economic interest not to produce to avoid incurring the fuel cost. To induce efficient energy production, the IESO pays generators the energy market-clearing price to cover these costs.[15] The market-clearing price is designed to reflect the cost to

[14] *Ibid.*

[15] The IESO currently operates a "two-schedule" pricing and dispatch energy market, which is described in the IESO's "The Single Schedule Market Backgrounder." In the two-schedule system, the physical limitations of the

produce one more MW of electricity (marginal cost), or the value to reduce one more MW of consumption (marginal willingness to pay) on the system. Paying generators this price incentivizes only those generators whose avoidable cost of economic activation is less than the market price. This is how the IESO manages the efficient use of the province's generation assets.

B.5 Q: Based on your experience in the electricity industry, what types of costs might a DR resource incur with an economic activation?

25. To my knowledge, the only cost that a DR resource may incur with an economic activation is the value of lost consumption, or what is sometimes called the value of lost load.[16] The value of lost load is the amount a consumer would be willing to pay to avoid disruption of service (i.e., to maintain its level of consumption). If a DR resource receives an energy activation when its value of lost load is greater than the price it would pay to consume, it would incur a legitimate cost from activation that it could have avoided if it had continued to consume. In this instance, the cost from activation would equal the difference between the value of lost load and the price the DR resource would have paid had it consumed.

B.6 Q: Does AMPCO provide evidence that DR resources are at risk of incurring this cost with an economic activation?

26. No. In fact, the IESO market rules provide DR resources the means to manage this risk. Two types of DR resources can participate in the TCA and the IESO's energy market: dispatchable loads and Hourly Demand Response ("HDR") resources.

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system are ignored in the "pricing" schedule that sets an Ontario-wide market price and establishes the most economic set of resources to meet demand. This requires a second "dispatch" schedule that includes the physical limitations of the system. The result is there are times when resources who cleared the market based on economics are told they cannot proceed, and others that were initially unsuccessful are told they are required to run in order to reliably meet demand. The differences between the two-schedules requires a complex system of out-of-market compensation to some participants.

[16] Navigant's Demand Response Discussion Paper, being Exhibit "I" to the Affidavit of David Short, sworn October 25, 2019, available online at: http://www.rds.oeb.ca/HPECMWebDrawer/Record/656576/File/document ["Navigant Report"]. The Navigant Report considers the costs associated with curtailment of a DR resource. This is the only type of cost they identified.

27. Dispatchable loads submit hourly energy bids to the IESO that define the quantities of energy they are willing to consume at different price levels. They receive dispatch instructions from the IESO every 5-minutes based on these energy bids. When they consume, they pay the market-clearing price (the 5-minute price) for the amount they consume. When the market-clearing price is above the price in their energy bid, they receive an economic activation to reduce their demand as per the amount stated in their energy bid. Dispatchable loads that are successful in the TCA are eligible to receive an availability payment by submitting and maintaining energy bids in the day-ahead through to real-time markets during a defined availability window that changes between the summer and winter months but generally covers the expected peak demand hours on business days. The energy bid prices must be greater than $100/MWh but less than $2,000/MWh, which is the maximum market-clearing price. As long as the price in the dispatchable load's energy bid reflects their value of lost load, they are not at risk of incurring a cost from an economic activation; they will only be economically activated when the market price exceeds their value of lost load.

28. HDR resources also submit hourly energy bids. When they consume, HDR resources pay the Hourly Ontario Energy Price ("HOEP"). In order to receive an availability payment, HDR resources must submit energy offers within the hours of availability. HDR resources receive a "standby report" in advance of a potential economic activation between 15:00 EST of the day ahead until 07:00 EST on the dispatch day, if the IESO's pre-dispatch schedules signal they could be curtailed for the hours of availability. In this instance, HDR resources must continue to submit energy bids for the dispatch day consistent with their capacity obligation. HDR resources are economically activated when the pre-dispatch 3-hour ahead price is greater than their energy bid price. The HDR resource is notified that they will be economically activated by receiving an Activation Notice approximately 2.5 hours before the start of the first dispatch hour to which it relates. HDR resources may be activated once per day for up to four consecutive hours. Attached hereto as **Exhibit "C"** is a copy of IESO Market Manual 4, which sets out the rules for activating HDR resources at section 7.2. Like dispatchable loads, HDR resources can manage the risk of incurring a cost associated with lost load from an

economic dispatch through their energy price bid. As the IESO evidence indicates, HDR resources have been economically activated on only one occasion since the implementation of the DRA.

B.7 Q: In response to Board Staff Interrogatory question 1, AMPCO provided a list of costs related to curtailment. What are your views on the nature of these costs?

29. AMPCO identified two types of costs related to economic activation under the heading "Cost per Curtailment." AMPCO called the first set of costs "lost opportunity". These costs all influence the price the DR resource is willing to pay to consume, i.e. the value of lost load. AMPCO indicates that there are several things to consider in establishing the value of lost load for a DR resource, and these things vary over time, even day to day and hour to hour. However, these costs all should be captured in the DR resource's energy bid price. As discussed above, the DR resource can avoid incurring a lost opportunity cost by properly estimating its value of lost load and using this estimated value for its energy bid price. This is not to say that it is easy to estimate the value of lost load, and that there is not a risk that the estimate is wrong and that there is ex post regret that they bid too low or too high. This is possible in the same way it is possible that when a generator submits an energy offer with an expectation of its fuel costs and operating conditions: they guess wrong and fail to recover some costs.

30. AMCPO calls the second set of costs "semi-variable costs," which included labour cost and other overhead costs for the production facility. These costs are costs that the DR resource must incur to ensure that they are available as a capacity resource to respond to an economic dispatch. These costs are not avoided if the DR resource is not economically activated. These are costs that can be avoided only if the DR resource chooses not to be available. I would call these costs fixed avoidable costs. For example, if they wanted to operate as a non-dispatchable load, they may require fewer staff on shift to monitor for dispatch instructions from the IESO. These costs should be recovered through the availability payment and not through an energy payment. This is no different than the types of costs that a non-committed generator may incur to make

sure a generator is available to respond to an IESO dispatch. Non-committed dispatchable generators would also need to recover these types of fixed avoidable costs if they choose to sell capacity and be available for dispatch by the IESO. They would include these costs in their capacity offer price, not in their energy offer price.

B.8 Q: If a generator receives an energy payment for balancing supply and demand, but a DR resource does not, is this not inequitable treatment, and does it not place the DR resource at a competitive disadvantage?

31. Contrary to AMPCO's assertion, I contend that *providing* DR resources an energy payment for economic activations would represent *inequitable treatment* and afford DR resources a *competitive advantage* over non-committed dispatchable generators in the TCA. I come to this conclusion by applying the concept of horizontal equity and by way of example.

B.9 Q: What is horizontal equity?

32. *Horizontal equity* requires that people who are alike in all relevant respect be treated the same. It corresponds to common notions of fair play and non-discrimination. For example, if two people have the same pre-tax income, they would have equal after-tax incomes. *Vertical equity* holds that people who differ in relevant respects should often be treated differently. This notion of equity is more contentious. Vertical equity is typically concerned with the "preferred" distribution of wealth in society. What represents the "preferred" distribution of wealth is a normative question that requires a value judgement. For example, it can be argued that those who earn higher pre-tax income *should* pay higher taxes.

B.10 Q: How does this concept of equity draw you to conclude that providing DR resources an energy payment would be inequitable?

33. I come to this conclusion through an example. The example is an adaptation of the example the IESO presented to stakeholders in the Demand Response Working Group

on March 11, 2018 to elicit views on the issue of the equal treatment of "negawatts and megawatts."[17]

34. Consider two companies, DR Corp. and GEN Corp. DR Corp. consumes 6 MW of electricity. Its value of lost load is $10,000/MWh. DR Corp. also owns a behind-the-meter generator. The generator has a capacity of 4 MW. It incurs a cost of $100/MWh to generate electricity. DR Corp. also incurs a fixed cost of $1,000 to staff and maintain the generator so that it is available to produce electricity when needed. If DR Corp. chose not to maintain the generator to be available to produce electricity, it would avoid incurring this cost. This makes the $1,000 a fixed avoidable cost. GEN Corp. is exactly the same as DR Corp. with one arbitrary exception: GEN Corp. is electrically connected to the IESO market metered separately as a load and a generator, while DR Corp. is connected by meter to the IESO market as a load with its generator operating behind the meter. Figure 1 depicts the situation for both companies.

35. To simplify the discussion, assume there is just one hour in the year and based on the prevailing supply and demand conditions, the two companies expect the energy market price to be $100/MWh. Both companies plan to compete in the IESO TCA. DR Corp., because it is metered with the IESO as a load, competes as a DR resource and can offer 4 MW of capacity (the amount of net-metered load it is capable of decreasing through use of its behind-the meter generator). If successful in the TCA, DR Corp. will be obligated to submit an energy bid in the IESO's energy market for 4 MW. The energy bid price that DR Corp. will submit is equal to $100/MWh as it will be less costly to use its generator to self-supply its demand than to buy energy from the IESO energy market at a price higher than $100/MWh. GEN Corp. competes as a non-committed generator and can offer 4 MW of capacity in the TCA. If successful in the TCA, GEN Corp. will

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[17] IESO Presentation to Demand Response Working Group on Utilization Payments Discussion, dated March 1, 2018, being Exhibit "J" to the Affidavit of David Short, sworn October 25, 2019, available online at: http://www.rds.oeb.ca/HPECMWebDrawer/Record/656576/File/document at 10-14 ["IESO March 1 Presentation"]. A "negawatt" is a unit of energy saved, such as through the curtailment of demand. This issue of whether a "negawatt" and a "megawatt" are functionally and economically equivalent is a contentious issue. The issue was addressed in FERC Order No. 745 where Commissioner Moeller disagreed with the Commission majority that the two were equivalent.

be obligated to submit an energy offer in the IESO's energy market for 4 MW. The energy offer price it will submit is \$100/MWh, which is its marginal cost of generation.

36. Assume in the first instance, as per the Amendments, DR resources do not receive an energy payment for an economic activation. What will be the capacity offer price of each company? I answer this with reference to Figure 1.A.

Figure 1: DR Corp. and GENCorp. are identical in all relevant aspects

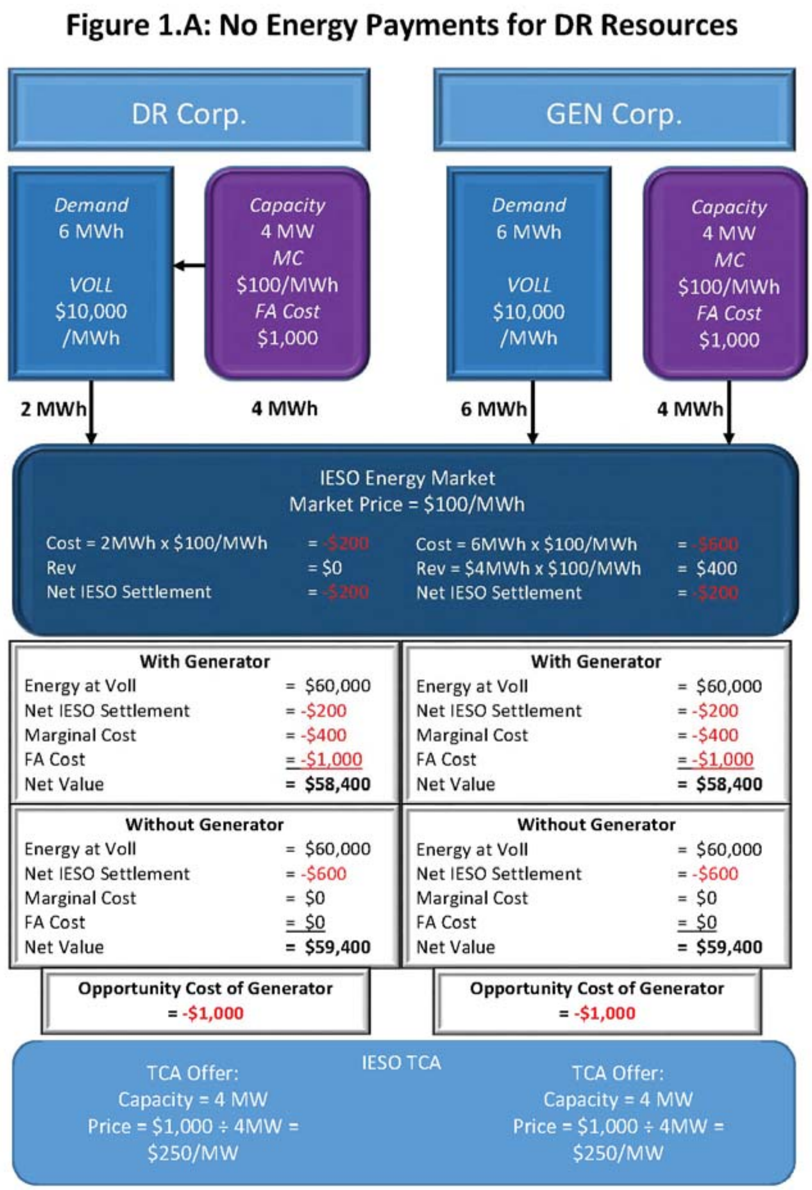
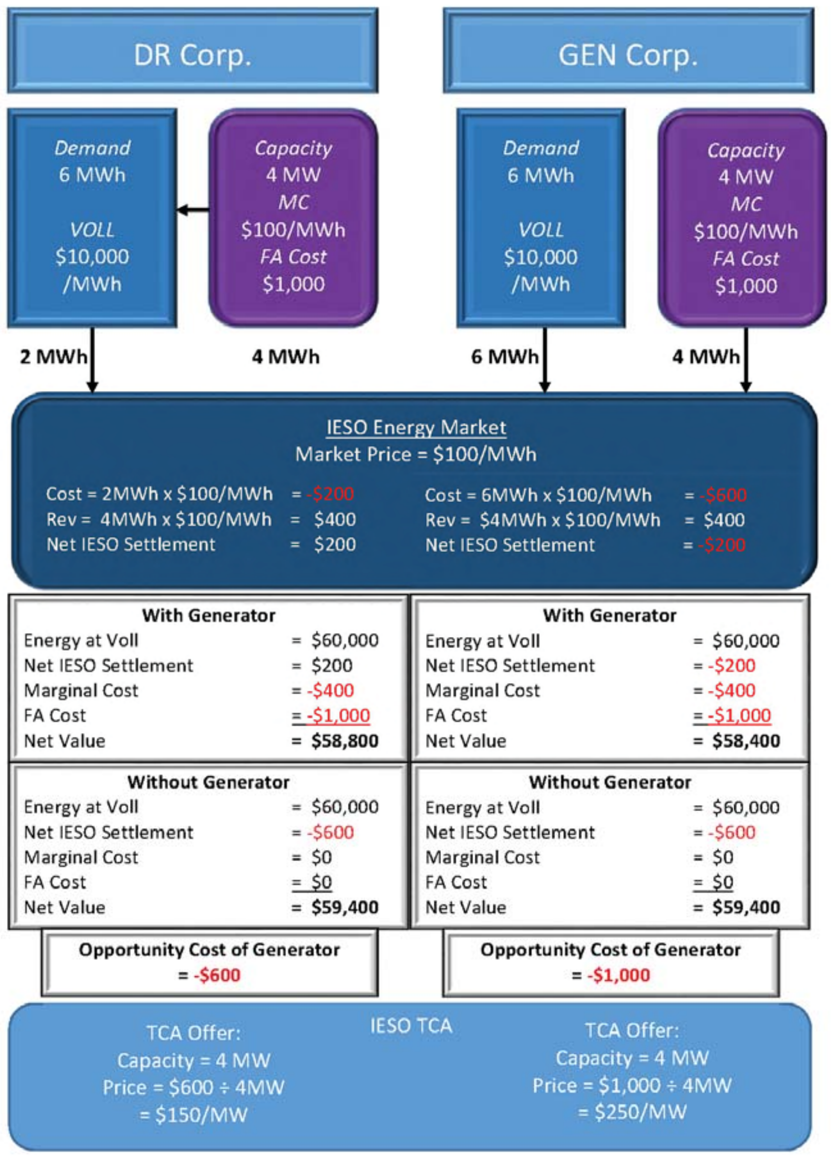


Figure 1.B: Energy Payments for DR Resources



37. With an expected market price of $100/MWh, DR Corp. anticipates that it will receive an economic activation to reduce its net-metered load by 4 MWh. It will not receive an energy payment for this activation, so as AMPCO argues, it will not be able to incorporate this revenue in the calculation of its capacity offer price. DR Corp. will make an energy payment to the IESO of $100/MWh x 2 MWh = $200 for its net-metered demand. It will incur a cost of $100/MWh x 4 MWh = $400 to generate electricity to

supply the balance of its 6 MWh of consumption. It will incur the fixed avoidable cost of $1,000 to ensure the generator is available. Overall, DR Corp. will realize a net value of $58,400 for its activities. These calculations are listed in the box for DR Corp. titled "With Generator" in Figure 1.A (numbers in red are negative values).

38. For it to be profitable for DR Corp. to participate in the TCA, the net value it realizes if successful must be greater than the net value it would realize by shutting down its generator and buying all of its electricity from the IESO. This net value is calculated in the box for DR Corp. titled "Without Generator" in Figure 1.A and is equal to $59,400. The net opportunity cost of DR Corp of participating in the TCA is the difference between these two values and is equal to -$1,000. That is, DR Corp. can increase its net value by $1,000 by shutting down its generator and saving the fixed avoided cost of $1,000 to maintain the availability of the generator. Therefore, to keep the generator available, it must recover this amount in the TCA through the availability payment. DR Corp. will submit a capacity offer price of $250/MW for 4 MW of capacity with the hope of recovering the fixed avoided cost of making the generator available. If it is not successful in the TCA, it will shut down the generator.

39. With an expected market price of $100/MWh, GEN Corp. anticipates that it will receive an economic activation to generate 4 MWh of energy. The IESO will pay GEN Corp. the market price per MWh of energy produced for a total energy payment equal to $400. As AMPCO conjectures, GEN Corp. can anticipate earning this energy revenue when calculating its capacity offer price. <u>**However, it costs GEN Corp. $400 to generate the electricity.**</u> What GEN Corp. factors in to its capacity offer price is not the revenue it earns, but the net revenue it earns which is the difference between the energy payment and variable energy cost. This is the "benefit" that GEN Corp. receives by participating in the energy market. As I will discuss more below, it is important to draw the distinction between the energy payment and the net revenue when considering the AMPCO's assertion of competitive advantage. In this case, the market price and GEN Corp.'s marginal cost are equal; GEN Corp. earns zero net revenue. Like DR Corp., GEN Corp. computes its capacity offer price based on the difference between the net value it realizes

from making its generator available and the net value it realizes if it shuts down the generator, which is -$1,000. GEN Corp. submits a capacity offer price in the TCA equal to $250/MW, the same as DR Corp. This is what we might expect given that DR Corp. and GEN Corp. are identical but for the arbitrary physical positioning of their meters.

40. Assume now that contrary to the Amendments, DR resources are paid the market price for an economic activation. How does this affect each company's participation in the TCA and in the energy market? This is presented in Figure 1.B above.

41. First, note that by receiving the market price for an activation, DR Corp. has an incentive to lower its energy bid price. It will be optimal to use its generator to self-supply its demand whenever the market price is greater than half its marginal generation cost (i.e., market price > $50/MWh). To see this, assume the market price is $51/MWh, and DR Corp. does not use its generator to self-supply. DR Corp. pays $51/MWh x 6 MWh = $306 to the IESO. If instead, DR Corp. does use its generator to self-supply, it pays only $51/MWh x 2 MWh = $102 to the IESO to consume, receives an energy payment for economic activation equal to $51/MWh x 4 MWh = $204, and incurs a generation cost of $400 for a net cost of $298. It is better off to self-supply when the energy market price is $51/MWh. By this reasoning, DR Corp.'s net cost of participation in the IESO market if it self-supplies is lower whenever the market price exceeds $50/MWh. As a result, DR Corp. will lower its energy bid price to $50/MWh from $100/MWh.

42. Now assuming that DR Corp.'s lower energy bid price does not result in a lower energy price (which it could), it will now factor this additional energy payment into its capacity offer price calculation. As Figure 1.B demonstrates, the net value to DR Corp. increases when it is eligible for an energy payment for an economic activation. DR Corp. requires a smaller capacity offer price of $150/MW in order to cover its fixed avoided cost of making its generator available. This capacity offer price is lower than the capacity offer price of GEN Corp.

B.11 Q: Can you summarize what this example demonstrates of AMPCO's assertions of inequality and competitive disadvantage?

43. Yes. The example shows that AMPCO's assertions are incorrect. In my example, DR Corp. and GEN Corp. are identical but for the physical placement of a meter; an arbitrary and irrelevant difference. Horizontal equity requires like treatment for people (or corporations) that are alike. When DR resources do not receive an energy payment for an economic activation, DR Corp. and GEN Corp., whom are identical, are treated alike for their participation in the IESO markets and realize the same net value for their activities. When DR resources receive an energy payment for an economic activation, DR Corp. avoids the cost of consuming by reducing its net-metered load (a benefit). At the same time, it receives a payment from the IESO to avoid this cost (a second benefit). This amounts to a double benefit for the energy service provided (as evidenced by DR Corp.'s willingness to submit an energy bid price that is half its marginal generation cost). As a result, DR Corp. realizes a higher net value than GEN Corp. for participation in the IESO markets, even though the two companies are identical. The preferential treatment gives DR Corp. a competitive advantage over GEN Corp. in the TCA. What amounts to a double benefit for the energy service allows DR Corp. to cover more of its fixed avoided cost through the energy market. DR Corp requires less in the way of an availability payment to cover these costs and hence they can submit a lower capacity offer price than GEN Corp. in the TCA.

B.12 Q: What other conclusion do you draw through this example?

44. Through this example, I can demonstrate that contrary to AMPCO's assertions, paying DR resources an energy payment for economic activations would harm fair and efficient competition. With only slight modifications to the example I described above, I can show that providing DR resources an energy payment for economic activations can lead to more expensive resources being selected before less expensive resources in the TCA and more expensive resources being dispatched ahead of less expensive resources in the energy market.

45. In Figure 2, I assume DR Corp. incurs a fixed avoided cost of $1,100 to staff and maintain its generator to ensure it is available to produce electricity, which is $100 higher than the previous example. DR Corp. is now a higher cost capacity resource than GEN Corp. DR Corp. will have to recover $100 more in the TCA than GEN. If as per the Amendments, DR resources do not receive an energy payment for economic activations, DR Corp. will submit a capacity offer price of $275/MWh in the TCA. It has less chance of success in the TCA than GEN Corp. From the perspective of promoting fair and efficient competition, this is the desired outcome; the least cost capacity resource is selected ahead of the higher cost resource. If in the alternative, DR resources are provided an energy payment for economic activations, DR Corp. can anticipate a benefit of reducing its energy payment to the IESO and receiving an energy payment from the IESO for doing so, (i.e., a double benefit). This reduces the amount of fixed avoided cost that it must recover through the TCA by $400. DR Corp. is now able to reduce its capacity offer price to $175/MW, which is lower than GEN Corp.'s capacity offer price of $250/MW. DR Corp. now has an advantage over GEN Corp. in the TCA, even though it is the higher cost capacity resource. As a result, it is possible that DR Corp. is successful in the TCA and GEN Corp. is not. GEN Corp. would be forced to shut down its generator. This would be a wasteful and inefficient use of the province's resources. Providing DR resources an energy payment for economic activations would be harmful to fair and efficient competition.

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

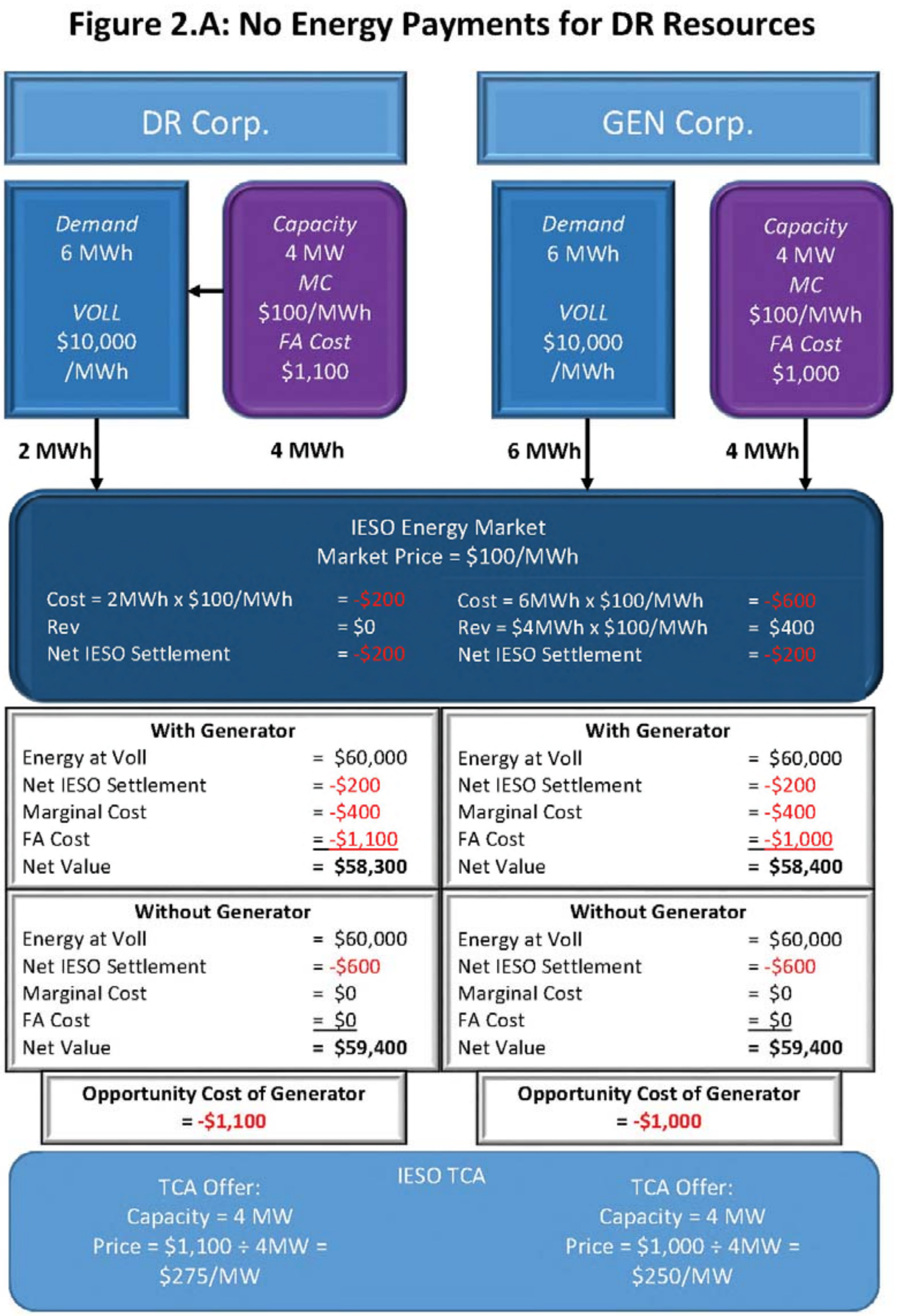


Figure 2.B: Energy Payments for DR Resources

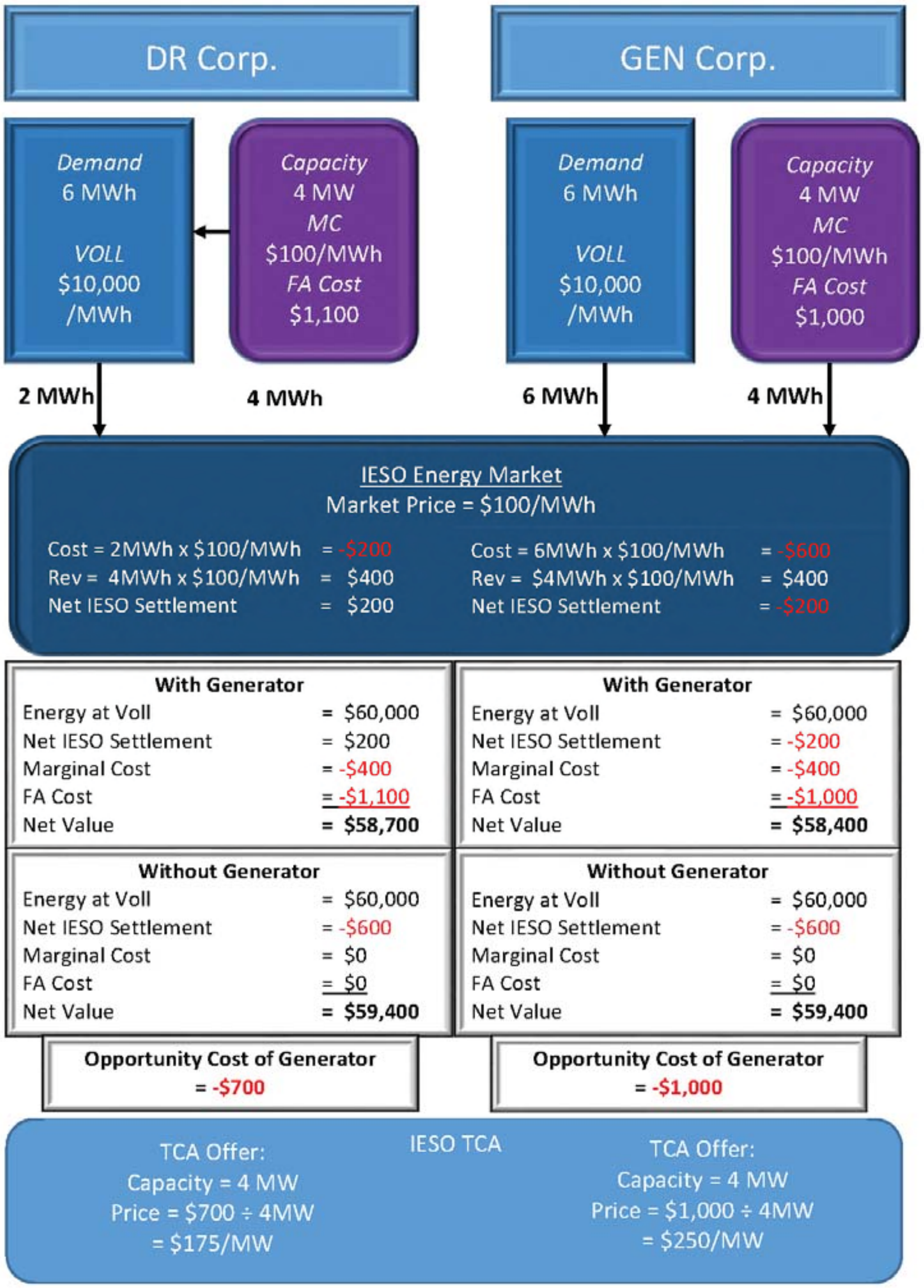


Figure 3: GEN Corp. has a lower marginal generation cost

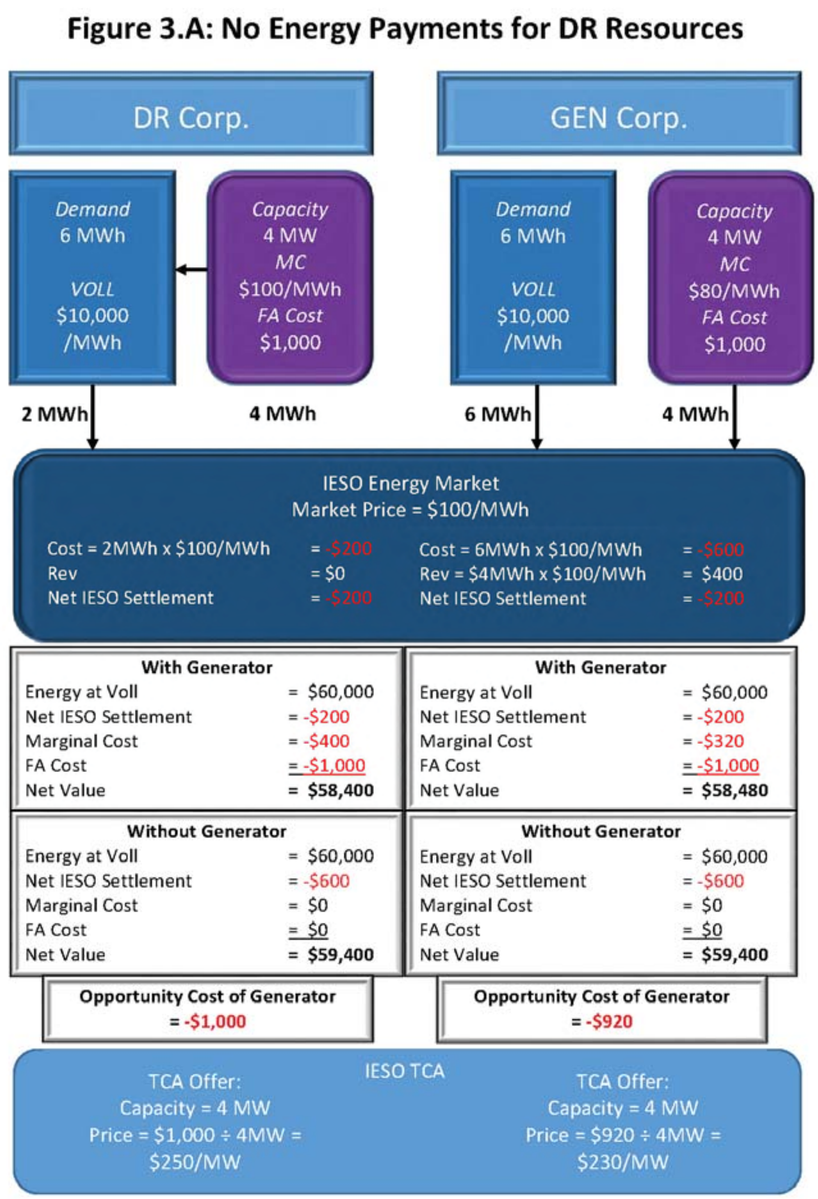
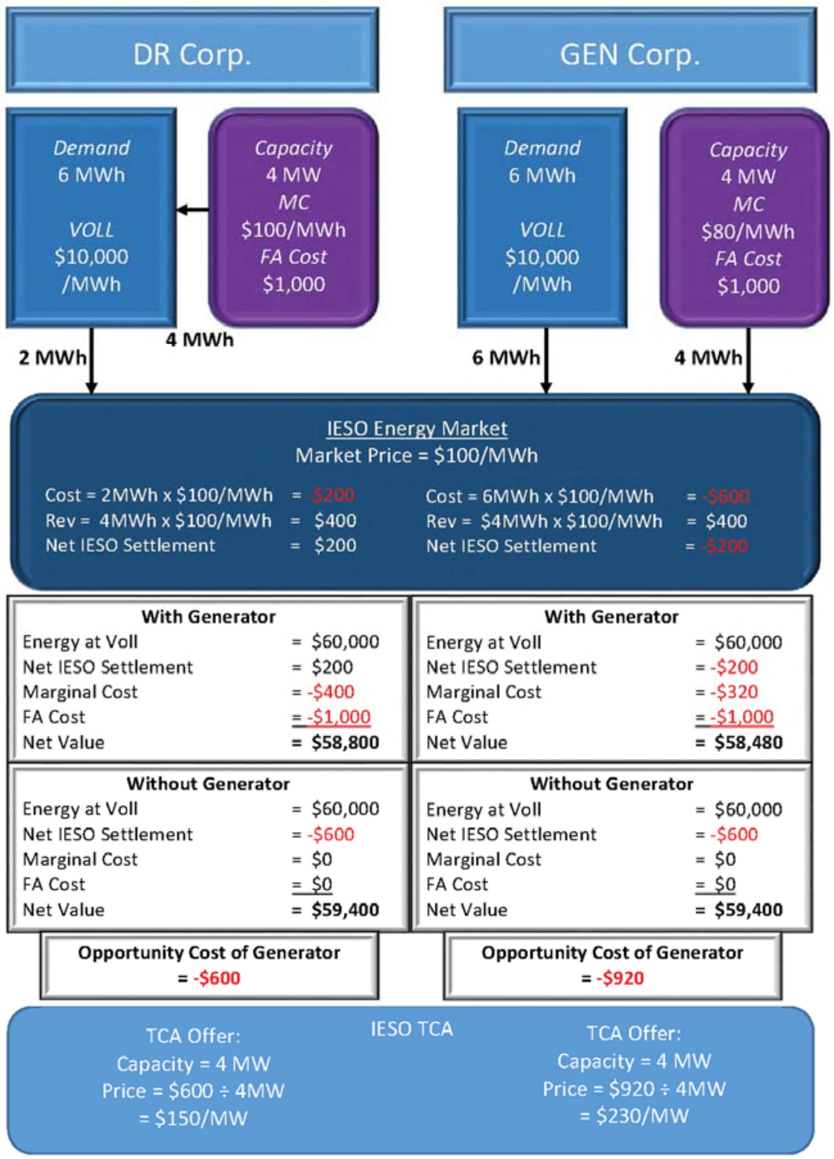


Figure 3.B: Energy Payments for DR Resources



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

payment; GEN Corp. will factor only the net revenue into its capacity price calculation as this is the only true benefit it receives from the energy market.

47. If DR resources are provided an energy payment for economic activations, Figure 3 illustrates that DR Corp. will submit a lower capacity offer price than GEN Corp. That is, because of the double benefit DR. Corp. receives from activation (a benefit for the energy payment it avoids and a benefit for the energy payment it receives) it has a competitive advantage over GEN Corp. It is also the case that because DR Corp. lowers its energy bid to $50/MWh, (half of its marginal generation cost) it will be dispatched ahead of GEN Corp. for energy. This is not only harmful to fair and efficient competition in the TCA, it leads to the inefficient dispatch of the province's generation resources, which is in conflict with the IESO's least cost dispatch objective.

B.13 Q: In your examples, you did not consider the effects of the Global Adjustment. How does the Global Adjustment affect your conclusions?

48. The manner in which consumers are charged the Global Adjustment will also provide certain DR resources a competitive advantage in the TCA over non-committed dispatchable generators, even if DR resources are not provided energy payments for an economic activation as per the Amendments.

49. The Global Adjustment is an accounting mechanism through which the fixed costs to build and maintain generation assets in the province and to deliver Ontario's conservation programs are recovered from Ontario electricity consumers. It is, at a high level, calculated as the differences between payments made to generators at the wholesale market price and payments made through regulation or contract that differ from the market price. The Global Adjustment was established in 2005 as a means to attract private investment in new generation capacity and to offer Ontario consumers price stability. The Global Adjustment has become the largest component of an average consumer's electricity cost, representing between 45 to 60 percent of a typical electricity bill. Attached hereto as **Exhibit "D"** is a copy of a policy brief I authored on this subject.

50. The Industrial Conservation Initiative ("ICI") is a government policy that defines how the costs in the Global Adjustment are allocated to different classes of consumers. Large consumers, known as Class A consumers, are charged global adjustment on the basis of their share of the total system demand during the highest five peak hours of the year. Class A consumers include consumers with an average monthly peak demand greater than 1 MW and consumers in certain manufacturing and industrial sectors, including greenhouses with an average monthly demand greater than 500 kilowatts (kW). Smaller consumers, known as Class B consumers, pay Global Adjustment as a monthly fee based on the kilowatt-hours of electricity they consume in the month, or as part of their regulated time of use prices. I understand that most AMPCO members qualify as a Class A consumer.

51. The Board's Market Surveillance Panel has shown that the ICI provides Class A consumers with an extreme price incentive to reduce their demand in the expected system peak demand hours to avoid paying the Global Adjustment. This will provide DR resources that are Class A consumers a competitive advantage over non-committed dispatchable generators in the new TCA. I demonstrate this in Figure 4. Attached hereto as **Exhibit "E"** is the Market Surveillance Panel's Report.

52. Figure 4 assumes the same characters for DR Corp. and GEN Corp. as Figure 1, except it also considers the effects of the incentives provided by the ICI. Both DR Corp. and GEN Corp. qualify as a Class A consumer. Assume that both companies anticipate the Global Adjustment charge to be $5,000/MWh. The Global Adjustment is charged based on the metered quantity consumed at the level of the IESO (i.e., based on metered quantities at the transmission level). As a result, DR Corp. can avoid Global Adjustment charges by self-suppling its demand and reducing its net-metered quantity with the IESO to 2MWh. GEN Corp. cannot avoid Global Adjustment by generating. As Figure 4.A demonstrates, even if DR resources are not provided an energy payment for economic activations, DR Corp. has an extreme incentive to generate electricity to avoid $5,000 x 4MWh = $20,000 in Global Adjustment charges. This decreases the opportunity cost of not incurring the fixed avoided cost to maintain the availability of its generator by

$20,000. DR Corp. is clearly better off by maintaining the availability of its generator; it will do so even if it does not earn an availability payment through the TCA. DR Corp. can offer a capacity price of $0/MWh in the TCA. In effect, the ICI rewards DR resources that are also Class A consumers by compensating them twice for making their generator available; once through the avoidance of the Global Adjustment (which recovers the capacity cost of the committed generator) and once through the availability payment. As Figure 1.B demonstrates, paying DR resources an energy payment for an economic activation would only further DR Corp.'s competitive advantage over the non-committed generator of GEN. Corp.

Figure 4: Effects of the Global Adjustment

Figure 4.A: No Energy Payments for DR Resources

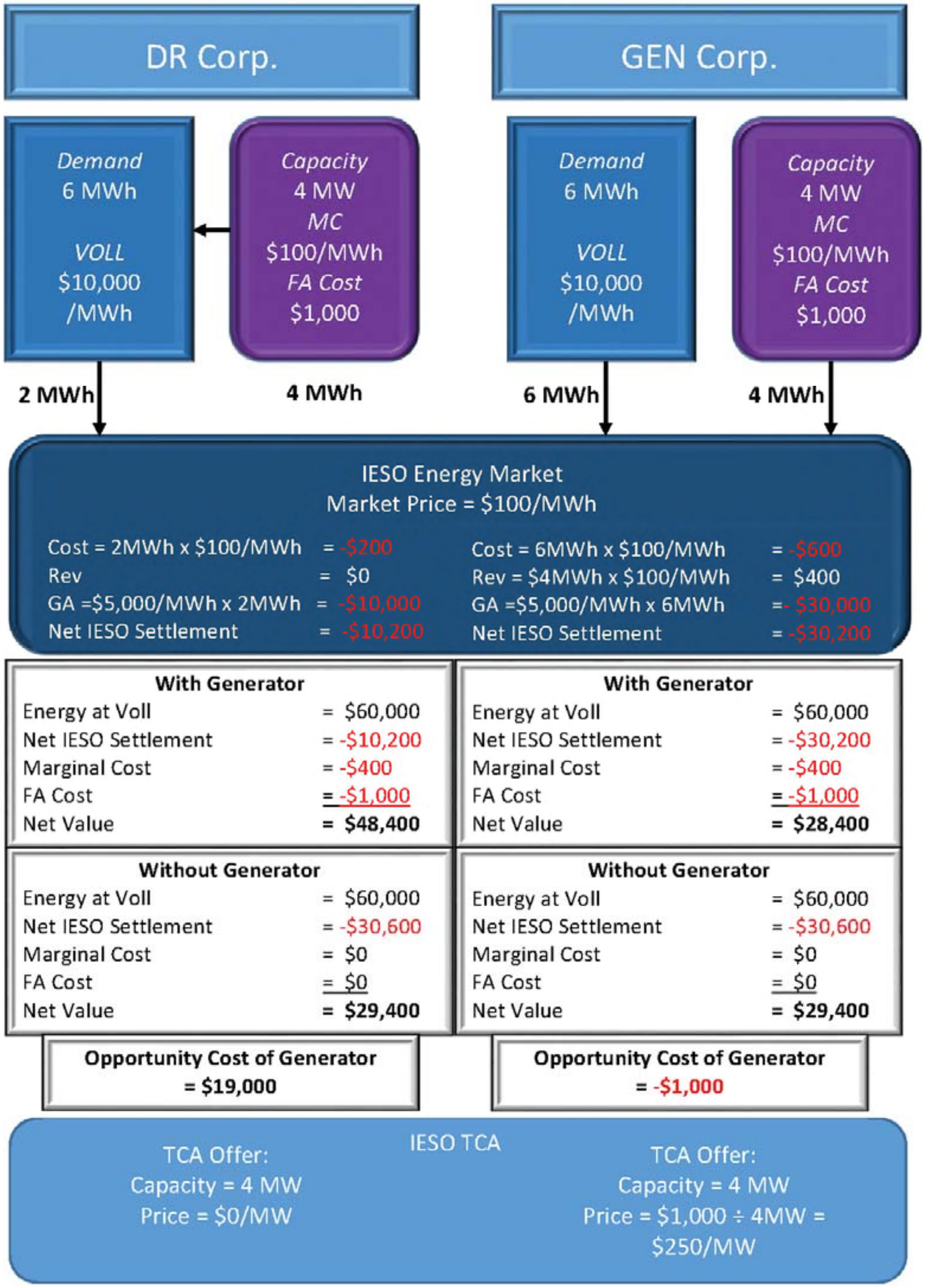
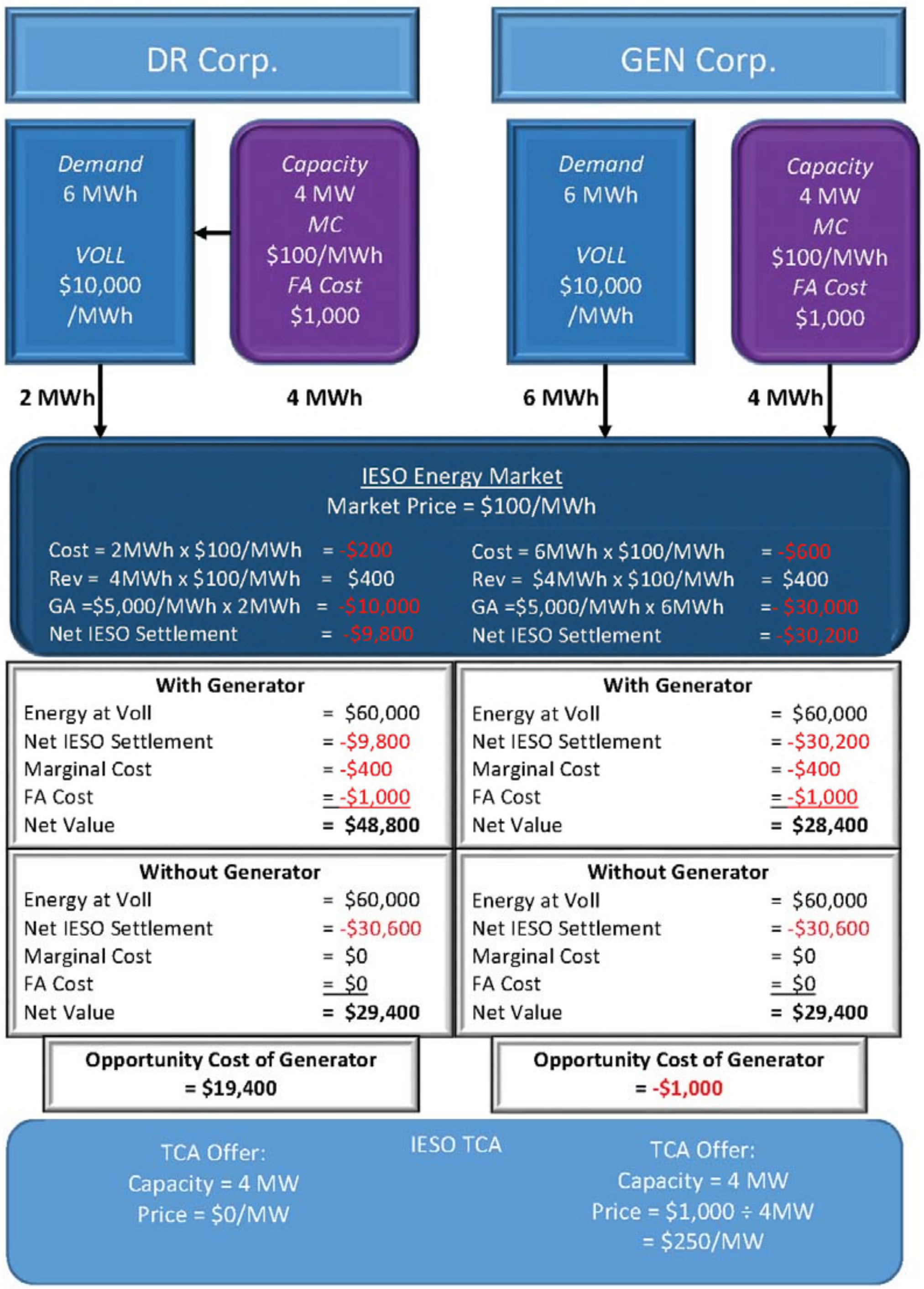


Figure 4.B: Energy Payments for DR Resources



C. APPLICATION OF FERC ORDER NO. 745 IN ONTARIO WILL NOT ACHIEVE THE COMMISSION'S INTENDED EFFECTS

C.1 Q: Can you briefly describe the conclusions of FERC Order No. 745

53. Yes. FERC Order No. 745 addressed the issue of compensation of DR resources in Regional Transmission Organization ("RTO") and Independent System Operator ("ISO") organized wholesale energy markets in the United States.[18] The Commission concluded that when a DR resource satisfies two conditions, it "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)."[19] ***First,*** the DR resource must have the capability to provide the service, which is described as displacing a generation resource in a manner that serves to balance supply and demand. ***Second***, the payment of the market price to the DR resource for the provision of the service must be "cost-effective" as determined by a "net-benefits test."

C.2 Q: What was the basis for the Commissions' conclusion?

54. The key objective of FERC Order No. 745 was to "remove barriers to participation of demand response resources in organized wholesale electricity markets."[20] FERC Order

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[18] FERC Order No. 745 at para. 9 focused on "customers or aggregators of retail customers providing, through bids or self-schedules, demand response that acts as a resource in organized wholesale energy markets".

[19] *Ibid* at para. 2.

[20] *Ibid* at para. 5. The Commission states this objective is "consistent with national policy requiring facilitation of demand response." It references Energy Policy Act of 2005, Pub. L. No. 109-58, § 1252(f), 119 Stat. 594, 965 (2005):

> "f) FEDERAL ENCOURAGEMENT OF DEMAND RESPONSE DEVICES.—It is the policy of the United States that time-based pricing and other forms of demand response, whereby electricity customers are provided with electricity price signals and the ability to benefit by responding to them, shall be encouraged, the deployment of such technology and devices that enable electricity customers to participate in such pricing and demand response systems shall be facilitated, and unnecessary barriers to demand response participation in energy, capacity and ancillary service markets shall be eliminated. It is further the policy of the United States that the benefits of such demand response that accrue to those not deploying

No. 745 was promulgated on the premise that "active participation by customers in the form of demand response in organized wholesale energy markets helps to increase competition in those markets."[21] Ensuring the competitiveness of organized wholesale energy markets is "integral to the Commission fulfilling its statutory mandate" and to ensuring "just, reasonable, and not unduly discriminatory or preferential rates."[22] The Commission observed that prior to the Order, "the level of compensation for demand response" varied from market to market, and that "some existing, inadequate compensation structures hindered the development and use of demand response." The Commission acknowledged that customers "must have confidence that appropriate price signals will be sustained by stable competitive pricing structures, before they will make an investment in demand response." Attached hereto as **Exhibit "F"** is a copy of the Commission's Notice of Proposed Rule Making in which these observations were made.

C.3 Q: Did the Commission elaborate on the types of barriers to DR resources that it was concerned with, and how FERC Order No. 745 would eliminate those barriers?

55. The Commission reasoned that "[d]ue to a variety of factors, demand responsiveness to price changes is relatively inelastic in the electric industry and does not play as significant a role in setting the wholesale energy market price as in other industries."[23] The Commission cited as barriers:

> "the lack of a direct connection between wholesale and retail prices, lack of dynamic retail prices (retail prices that vary with changes in marginal wholesale costs), the lack of real-time information sharing, and the lack of market incentives to invest in enabling technologies that would allow

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such technology and devices, but who are part of the same regional electricity entity, shall be recognized."

[21] *Ibid* at para. 9.

[22] *Ibid* at para. 8.

[23] *Ibid* at para. 57.

> electric customers and aggregators of retail customers to see and respond to changes in marginal costs of providing electric service as those costs change."

The Commission concluded, "paying LMP can address the identified barriers to potential demand response providers."[24]

C.4 Q: You indicated that for DR resources to be eligible for compensation it must be cost-effective as determined by the FERC net benefits test. Can you explain this test?

56. Yes. The Commission recognized that paying DR resources the market price to curtail demand would have two effects. First, paying DR resources the market price would encourage more participation of these resources in the energy market. Their participation would involve an energy bid in the wholesale market. Additional energy bids in the market would lead to a lower wholesale energy price whenever a DR resource's bid was selected in the energy market ahead of a generator offer. All other consumers (non-DR consumers) would realize a benefit from the lower price. Second, these non-DR consumers would have to make an additional payment to the DR resource equal to the market price times the amount of demand curtailed. The net benefits test is satisfied when the savings the non-DR consumers realize from the lower wholesale price are greater than the additional payment they must make to DR resource. FERC Order No. 745 refers to this as the "the billing unit effect of dispatching demand response."[25] In this sense, paying DR resources is deemed cost effective if it leads to lower bills for all non-DR consumers.

C.5 Q: Is this how an economist would define "cost-effective"?

57. No. As many commentators noted in the FERC proceeding, in economics, an outcome would be defined as cost-effective if it leads to society making the best use of its

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[24] *Ibid* at para. 58.

[25] *Ibid* at para. 3.

available resources. Economist call this an allocatively efficient outcome. An allocatively efficient outcome maximizes the benefits to all participants. This is sometimes called "total surplus" which is equal to the sum of consumers' surplus (the difference between what they are willing to pay and the price they pay) and producers' surplus (the difference between the price they receive and avoided variable cost). The IESO's dispatch model seeks to maximize allocative efficiency or total surplus. The net benefits test seeks to maximize the benefit to non-DR participants, or non-DR consumers' surplus and comes at the expense of producers' surplus. Promoting efficiency is also a purpose of the *Electricity Act, 1998*.

C.6 Q: Do you see any implications for the IESO or Ontario consumers if the IESO were required to apply a net benefits test in order to pay DR resources the market-clearing price?

58. Yes. If the intent of the FERC net benefit test is to compensate DR resources only when it results in a reduction in the bills of non-DR consumers (non-DR consumers' surplus), then the IESO would have to take into account the effect of the Global Adjustment in this calculation. This has two implications for the IESO and Ontario consumers. First, it means that (all else held constant) the net benefits test will be satisfied less frequently (if ever) than in the United States markets.[26] Second, it adds additional complications for the IESO in implementing the test that the United States RTO/ISOs did not have to encounter. Furthermore, as several commenters noted in the FERC proceeding, "cost-effective" as defined by the net benefits test, and "allocative efficiency" are different things. An additional implication of Ontario implementing the net benefit test is that it could, if ever satisfied, contribute to a less efficient dispatch of resources and less efficient use of the province's generation resources. This is a point I already established above.

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[26] This same point was recognized in Section 3.2 of the "Navigant Report".

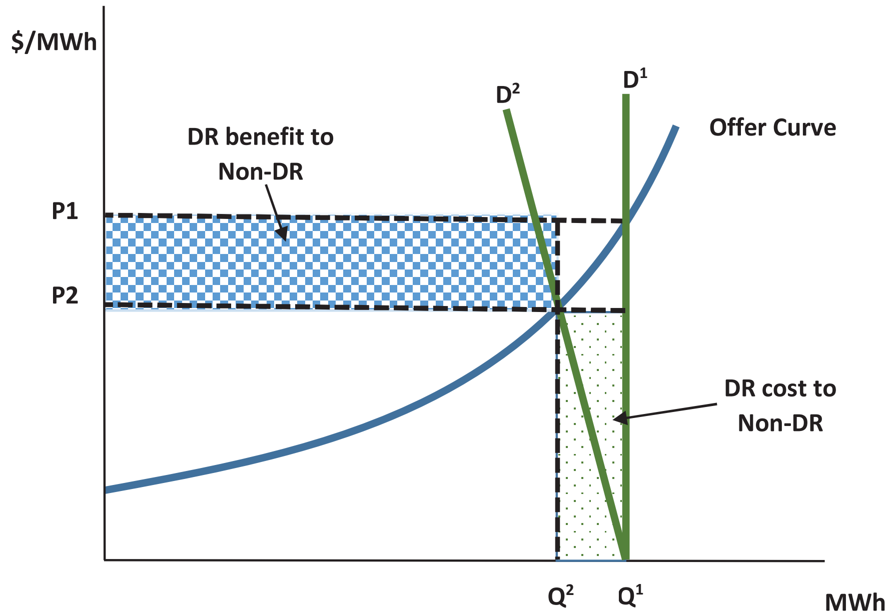
C.7 Q: Can you explain why the Global Adjustment means the net benefits test is not likely to be satisfied on Ontario?

59. Yes. This can be explained with reference to Figure 5. In Figure 5, an hourly offer curve and an hourly demand curve (labeled D^1) are drawn. The demand curve D^1 is drawn under the assumption that DR resources are not provided an energy payment for an economic activation. The market-clearing price is determined as the intersection of the hourly offer curve and the hourly demand curve, which is P^1 in Figure 5. This illustration is based on a figure contained in the Californian ISO's final proposal for implementation of FERC Order No. 745, which is attached hereto as **Exhibit "G".**

60. Paying a DR resource the market-clearing price for an economic activation changes the DR resource's incentives for participation in the market. This was the desired effect of the Commission in FERC Order No. 745. As I outlined above, in the Ontario context, if a DR resource is paid the market price for an economic activation, it will be incentivized to submit a lower energy bid price.[27] This causes the demand curve to become more "elastic" and shift downward. This is represented by the new hourly demand curve D^2 in Figure 5. The lower DR resources' energy bids mean that the market clears at the lower price of P^2.

[27] This point was discussed in the "IESO March 1 Presentation" at 5.

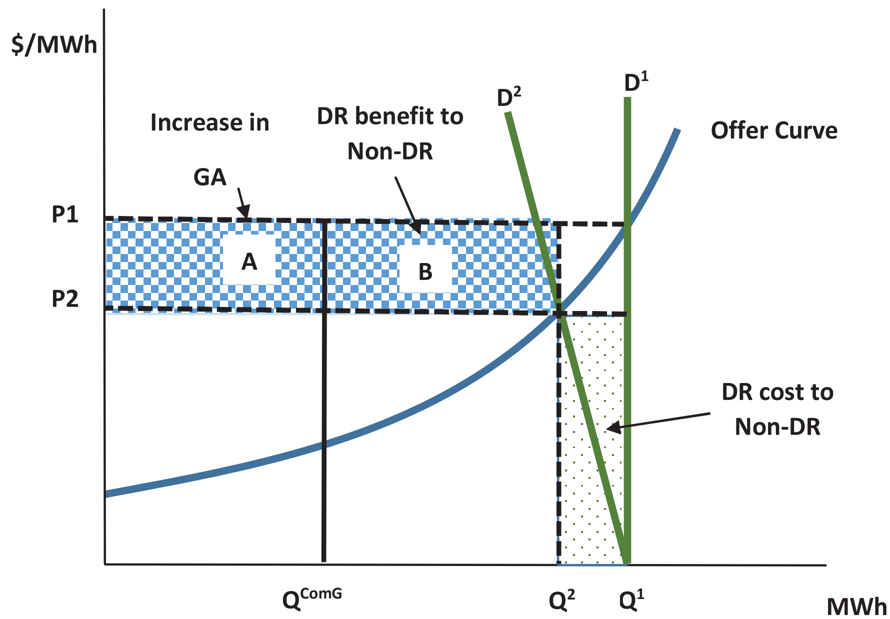
Figure 5: The Net Benefits Test under FERC Order No. 745



61. The FERC net benefits test is satisfied if the savings the non-DR consumers realize from the lower wholesale price are greater than the additional payment they must make to DR resources. Under the FERC model, this occurs when the shaded blue area is greater than the shaded green area in Figure 5.

62. If the net benefits test were applied to Ontario, the IESO would have to incorporate the effects of payments made to contracted and regulated ("committed") generators by non-DR consumers through the Global Adjustment. As discussed above, the Global Adjustment includes differences between payments made to generators at the wholesale market price and payments made through regulation or contract that differ from the market price. If providing DR resources an energy payment for economic activations lowers the market-clearing price as the Commission expected in FERC Order No. 745, in Ontario, a portion of the benefit non-DR resources get from the lower energy price will be offset by an increase in the payments the same consumers have to make to committed generators through the Global Adjustment. This means that all else held constant, the net benefits test condition for compensating DR resources will be satisfied less often in Ontario than in the United States. This is illustrated in Figure 6.

Figure 6: The Net Benefits Test illustrated for Ontario



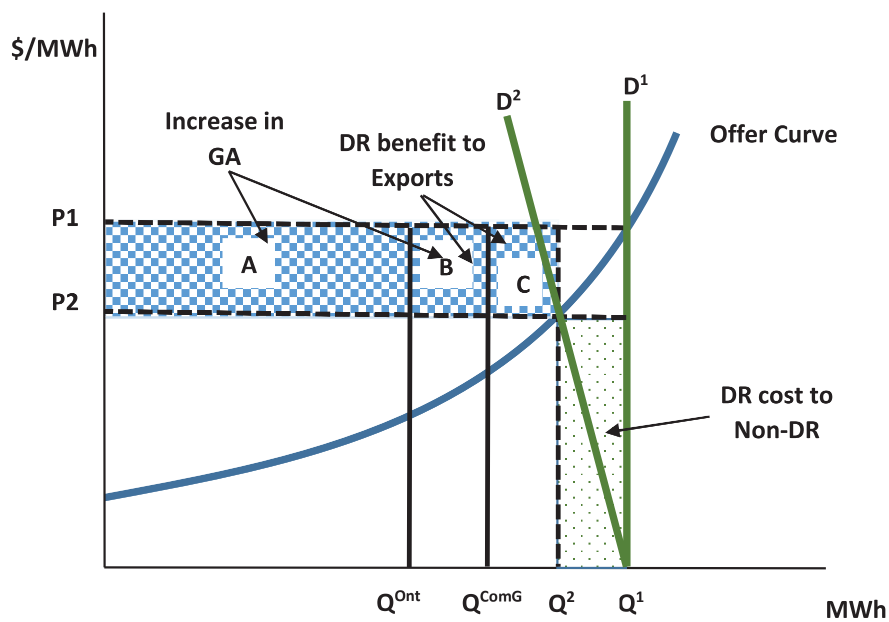
63. In Figure 6, the amount of supply provided by committed generators is Q^{COMG}. When lower energy bid prices of DR resources cause the energy market price to fall from P^1 to P^2, the amount of net revenues earned by the committed generators falls in proportion to the price decrease (the area marked as A in Figure 6). The decline in net revenue is fully offset by higher payments to the committed generators as per their contract terms or regulated rates. Non-DR consumers cover these higher payments through higher Global Adjustment charges. As a result, the benefit that non-DR consumers receive from the lower energy price is reduced by the amount A; they realize the smaller benefit represented by area B. Since the net benefit is smaller in Ontario, it is less likely that the net benefits test condition will be satisfied in Ontario.

C.8 Q: Are there conditions in Ontario in which the net benefits test is certain to fail?

64. Yes. Ontario is a large net exporter. Exporters do not pay the Global Adjustment. In many hours, committed generators are required to produce to meet both the Ontario demand and the export demand. When the amount of energy provided by committed

generators exceeds the Ontario demand, energy price decreases caused by lower DR resource energy bids would lead to an increase in Ontario non-DR consumers' Global Adjustment charges that exceeds benefits they realize from lower energy market prices. That is, exports would realize the benefit of the lower market prices, but because Ontario consumers must cover the higher Global Adjustment charges, they would be worse off, even before paying DR resources not to consume. This is illustrated in Figure 7.

Figure 7: Sufficient condition for Net Benefits Test failure in Ontario,



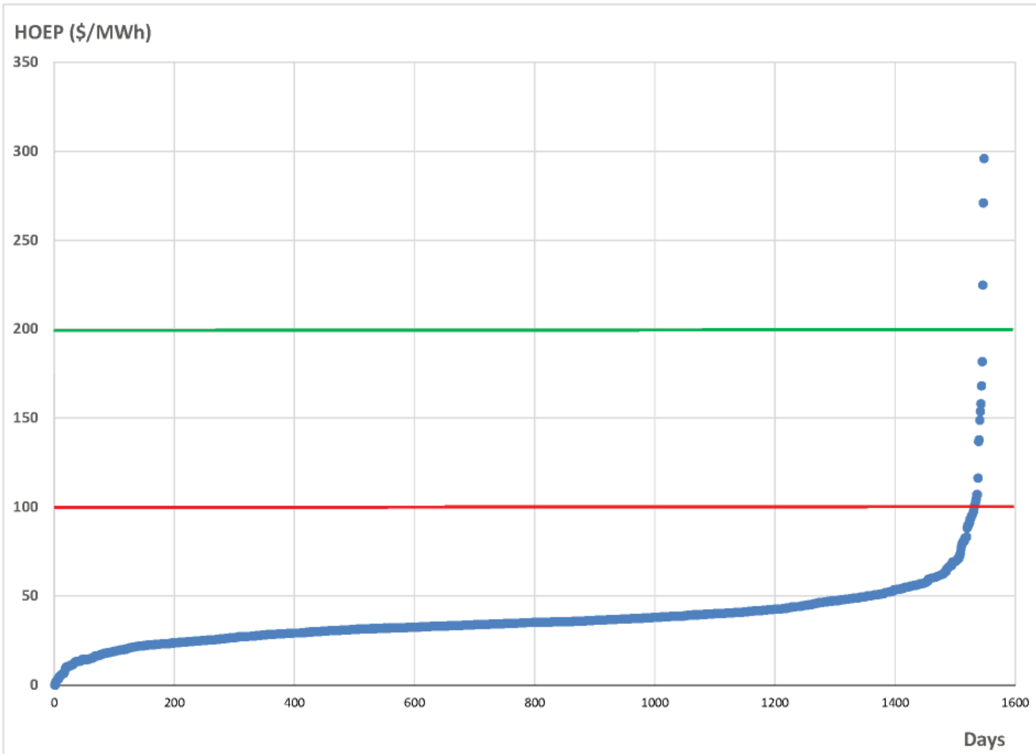
65. In Figure 7, the Ontario non-DR consumers' demand is Q^{ONT}. The difference between Q^2 and Q^{ONT} is export demand. The amount of energy produced by committed generators is Q^{COMG}, which is greater than the Ontario non-DR consumers' demand. The benefit that non-DR consumers realize from the energy price reduction is represented by the area A. However, the amount of Global Adjustment that these consumers will have to pay increases by the area A + B. Ontario non-DR consumers are made strictly worse off by compensating DR resource for economic activations. They are made worse off even before accounting for the amount they have to pay to DR resources for economic activations (the green shaded area).

C.9 Q: Have you done any analysis that could provide the OEB some guidance on the likelihood that the net benefits test would be satisfied in Ontario?

66. Yes. The IESO provided me with hourly data for the period January 1, 2018 to October 28, 2019 which is attached hereto as **Exhibit "H"**. The data included hourly HOEP and hourly quantities of Ontario non-dispatchable demand, Ontario dispatchable load demand, committed generation output, non-committed generation output, exports and imports for a total of 15,984 hours. I calculated the number of hours when output from committed generators exceeded Ontario non-dispatchable demand plus dispatchable load demand (the sufficient condition for the net benefits test to fail in Ontario). There were 14,436 hours out of 15,984 hours (90.3% of hours) in which the output of committed generators exceeded the Ontario demand between January 1, 2018 and October 28, 2019. The net benefits test would have failed in these hours.

67. In the remaining 1,548 hours (9.7% or hours) when Ontario demand was greater than the output of committed generators, I considered the likelihood that compensating DR resources for economic activations would lead to sufficient reductions in DR resources' energy bid prices to cause a decrease in the energy market price. If DR resource energy bid prices remain relatively high, then it is not likely a price decrease could occur and hence a net benefit to non-DR consumers is not possible. Figure 8 provides some insights in the number of hours that this might be possible. Figure 8 ranks the 1,548 hours between January 1, 2018 to October 28, 2019, in which Ontario demand exceeded committed generation output, from lowest HOEP to highest HOEP.

Figure 8: HOEP in hours with Ontario demand greater than committed generation Output, January 1, 2018 to October 28, 2019



68. First, DR resources must submit energy bid prices that are greater than $100/MWh. Compensating DR resources for economic activations could not have a net benefit in hours when the HOEP was less than $100/MWh because DR resource energy bid reductions could not fall below this price level. HOEP exceeded $100/MWh in only 17 of the 1,548 hours (0.106% of all hours in the data set).

69. IESO analysis found in a presentation to the Demand Response Working Group indicated the following:

> The historical contracting programs required DR energy bids to be priced at $200/MWh. Once the $200 price requirement was removed for HDR resources, the IESO observed that the majority of DR bids were priced by participants much higher than $200/MWh. This implies DR

participant's value of energy consumption is much higher than this level.[28]

70. If we consider prices above $200/MWh as the benchmark for a possible price effect, there were only 3 of the 1,548 hours (0.019% of the total hours in the data set) in which the HOEP exceed this benchmark.

71. Overall, recent historical data suggest that the net benefits test would rarely, if ever, be satisfied in Ontario (0.019% of the time).

C.10 Q: You also said that there would be additional complications for the IESO to implement the FERC net benefits test. What are the additional complications?

72. FERC Order No. 745 required the RTO/ISO's "to develop a mechanism as an approximation to determine a price level at which the dispatch of demand response resources will be cost-effective."[29] Essentially, the ISO and RTOs are required to use historic offer data, adjusted to reflect resource availability and fuel costs, to create a representative aggregated supply curve for a trade month.[30] This representative curve is used to determine "the monthly threshold price corresponding to the point along the supply stack beyond which the overall benefit from the reduced LMP resulting from dispatching demand response resources exceeds the cost of dispatching and paying LMP to those resources."[31] The ISO and RTOs must post this threshold price on their website and update it on a monthly basis.

73. As discussed above, the IESO will require additional information to implement the net benefits test in Ontario. They will require a forecast of Ontario non-DR load, the production of committed generation and the amount of net exports. Realistically, these values will change often during the month, which makes the use of a representative

[28] "IESO March 1 Presentation" at 7.

[29] FERC Order No. 745 at para. 4.

[30] This is described in Exhibit "G".

[31] FERC Order No. 745 at para. 4.

supply stack and a monthly price test less practical. Furthermore, applying a blunt monthly test is more likely to lead to false positives and harm to Ontario consumers given the unique conditions and relative infrequency in which the net benefits test is likely to be satisfied. The IESO would likely have to identify improvements to the way the nets benefits test is implemented in Ontario compared to the United States to limit false positives.

C.11 Q: Do you think there are any other aspects of the Ontario market that should inform a decision of whether or not to apply FERC Order No. 745 in Ontario?

74. Yes. As I outlined above, the key objective of FERC Order No. 745 was to "remove barriers to participation of demand response resources in organized wholesale electricity markets."[32] The Commission stated in its Notice of Proposed Rule Making that:

> "Despite the benefits of demand response and various efforts by the Commission, ISOs and RTOs to address barriers to and compensation for demand response participation, demand response providers collectively play a small role in wholesale markets. After several years of observing demand response participation in ISO and RTO markets with different, and often evolving, demand response compensation structures, the Commission is concerned that some existing, inadequate compensation structures have hindered the development and use of demand response."[33]

75. FERC Order No. 745 further describes the types of barriers to demand response participation that concerned the Commission. These barriers primarily related to the disconnect that existed at the time between wholesale and retail prices and the lack of incentives this created for the investment in the capability to be price responsive.[34]

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[32] *Ibid* at 113.

[33] Exhibit "F" at para. 9.

[34] FERC Order No. 745. This was a point made by Commissioner Moeller on his dissenting opinion: "the lack of dynamic prices at the retail level is the primary barrier to demand response participation."

FERC Order No. 745 sought to remedy these barriers by providing DR resources additional compensation.[35]

76. However, the types of barriers to demand response the Commission was concerned with at the time of FERC Order No. 745 do not seem relevant to present day Ontario. First, as Navigant noted in a report prepared for the IESO:

> "It is important to note that Ontario is different from many U.S. jurisdiction in that many of the DR resources are wholesale market participants or large customers that are exposed to real-time electricity prices as opposed to retail prices. This means that Ontario DR customers avoid the entire real-time electricity price when curtailing and are exposed to high price spikes. When DR providers are only exposed to retail rates as they are in many U.S. jurisdictions, they are unlikely to have the same avoided cost benefit when curtailing during spikes in prices."[36]

77. Second, Ontario has already done a great deal to help DR resources recover the costs of investments needed to enable their participation in wholesale markets. As early as 2007, the IESO (formerly the OPA) recognized the capacity value of DR resources and implemented the DR3 program. The DR3 program procured DR resources through multi-year standard offer contracts that paid DR resources both an availability payment and a utilization payment. The proceeds of the availability payment could contribute in the investment in meters and control systems that would enable price responsiveness. It

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[35] *Ibid.* Commissioner Moeller in his dissenting opinion challenged the majority on this point. Commissioner Moeller stated in his dissent:

> "The Rule [FERC Order No. 745] finds that "greater uniformity in compensating demand response resources" is required and as justification for its action, references the existence of various barriers that limit the participation of demand response in the energy markets. The majority ultimately concludes that these barriers can be removed by better equipping demand response providers with the financial resources to invest in enabling technologies. This is to say that the majority believes that paying demand resources more money will help overcome these barriers and encourage more participation. The Rule, however, never clearly explains how the existence of barriers, in turn, justifies a payment of full LMP to demand resources."

[36] "Navigant Report".

also helped fund investments made by load aggregators to sign-up and compensate consumers that could reduce demand upon an activation from the IESO. In 2015, the former OPA DR3 program was integrated into the IESO-administered market through a program called capacity backed demand response and through the DRA. This provided further learning for the IESO and DR resources on how demand response could respond to economic activations. DR resources were provided availability payments for providing the capacity service, which again could be used to fund investments in the technologies needed to enable demand response. These availability payments were made during a time when Ontario had more than enough capacity to meet its obligations. This means Ontario consumers paid to help remove the barriers to demand response when it did not need the capacity. Arguably, as evidenced by the number of DR resources that now participate in the DRA, Ontario has been successful in removing the types of barriers to demand response participation in the wholesale market that were the focus of FERC Order 745.

78. Third, the ICI has been very effective at stimulating demand response during peak demand periods. The Market Surveillance Panel estimates that "ICI participants reduced their consumption by 42% during peak demand conditions in 2016."[37] They do so to reduce the amount of Global Adjustment that they pay. The Panel "estimates that by reducing consumption by one megawatt during each of the five peak demand hours in 2016, a Class A consumer would have saved approximately $520,000 in Global Adjustment charges."[38] The benefit from reducing peak hour consumption are so significant, it "creates an incentive for Class A consumers to invest in new generating or storage capacity located at their facilities."[39]

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[37] Exhibit "E" at 2.

[38] *Ibid* at 8.

[39] *Ibid* at 16.

C.12 Q: Are you aware of any research that demonstrates the effect that FERC Order No. 745 has had on the United States wholesale markets?

79. Yes, in the short time that I had to prepare this testimony, I conducted a non-exhaustive scan of the academic literature and reports prepared by the RTOs, ISOs and their market monitors for empirical evidence on the effects and implications of the implementation of FERC Order No. 745. I was surprised to find only a few reports or academic papers on the topic.

80. Monitoring Analytics LLC, the market monitor for PJM, prepare quarterly and annual reports on the PJM market. They dedicate a section in the reports specifically to demand response. Attached hereto as **Exhibit "I"** and **Exhibit "J"**, are the 2015 and 2019 Quarterly State of the Market Reports. The 2015 report states that FERC Order No. 745 "increased incentives to participate" in the PJM economic demand response program.[40] Figure 6-2 shows a sudden increase in both credits paid to economic demand response and economic MWh reductions starting in April 2012, when PJM implemented the Order No. 745. The 2019 report includes the same Figure 6-2, which shows the elevated levels of credits, and MWh reductions largely continued through 2019 and then subsided, although they are still above the April 2012 levels.[41]

81. The reports also provide the monthly net benefits test threshold prices. Threshold prices have never exceeded $34.07/MWh since April 2012 when PJM implemented Order No. 745.[42]

82. Steve Dahlke and Matt Prorok published a paper in the Energy Journal in 2019 that estimated the consumer savings, CO_2 emission reductions, and price effects that *could* be achieved in the MISO electricity market through the removal of regulatory and market rule barriers to market-based deployment of DR. This paper is attached hereto as **Exhibit "K"**. They argue that even after implementation of FERC Order No. 745,

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[40] Exhibit "I" at 213.

[41] Exhibit "J" at 297.

[42] *Ibid* at 300.

there continue to be barriers to DR participation in MISO and that considerable consumer savings and CO_2 emissions could be realized through the removal of the barriers. Through their analysis, they uncover a shortcoming of the FERC net benefits test. They note that DR resources that reduce their consumption in a peak hour because of an economic activation often shift their consumption to future off-peak hours. The shift in consumption increases the price in the future hours and reduces some of the benefits to non-DR resources. That is, "deploying demand response resources that pass the net benefits test in the hour they were deployed actually increased overall costs after taking into account the off-peak increase of energy."[43]

83. Kai Van Horn et al, published a paper in the Electricity Journal in October 2013 that also identified shortcomings in the net benefits test and proposed improvements to the test. This paper is attached hereto as **Exhibit "L"**. Van Horn et al, argue the failure of the net benefits tests "to integrated the impacts of transmission is a significant limitation that has unintended consequences for the total benefits which DR resources may bring to the system and for the distribution of those benefits among the buyers in the system."[44]

84. Xu Chen and Andrew N. Kleit published a paper in the Energy Journal in 2016 (attached hereto as **Exhibit "M"**) that provided empirical result to show how incentive-based DR programs can be "manipulated" to inflate customer baseline load measurement. They suggest, "policy makers in FERC, RTOs and states regulatory agencies consider the threat of manipulation when modifying DR market rules following the Supreme Court's recent upholding of the FERC Order 745."[45]

85. Finally, David Brown and David Sappington published a paper in the Journal of Regulatory Economics in 2016 that derives an optimal DR policy and uses the optimal

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[43] Exhibit "K" at 258.

[44] Exhibit "L" at 152.

[45] Exhibit "M" at 201.

policy to estimate the welfare losses that can arise under FERC Order No. 745. This paper is attached hereto as **Exhibit "N"**. They show that the implementation of Order No. 745 overcompensates DR resources and "reduces welfare well below the level secured by the optimal DR policy."[46] They argue that the policy offered by the critiques to FERC Order No. 745, to compensate DR resources the difference between LMP and the retail rate provided higher welfare than compensation at full LMP as per the FERC Order No. 745.

D. SUMMARY CONCLUSIONS

D.1 Q: Can you summarize for the Board the key findings of evidence?

86. Yes. The evidence in my testimony demonstrates the following.

87. First, the Amendments provide an equitable treatment of TCA participants. Horizontal equity requires that like people be treated alike. I show by way of example, that two identical companies, which differ only by the arbitrary placement of their meters, are treated exactly alike under the Amendment; *horizontal equity*. I then show that compensating DR resources for an economic activation provides preferential treatment to the company that operates a behind-the meter generator; *horizontal inequity*. The company that operates the behind-the-meter generator, DR Corp. is provided preferential treatment because it benefits twice when it reduces its net-demand with the IESO: first, it reduces the energy payment it makes to the IESO, and second, it receives a payment from the IESO for doing so.

88. In my opinion, applying the horizontal equity test is a more accurate way of assessing equitable treatment, than a test of functional equivalence in service provided, which is the test I understand AMPCO has asked the Board to rely on in this matter. As my example demonstrates, both DR Corp. and Gen Corp. are functionally equivalent in terms of their capability of balancing supply and demand on the IESO controlled grid;

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[46] Exhibit "N" at 265.

one by reducing demand and one for producing electricity. Doing so fails to recognize that DR Corp. is effectively compensated twice for reducing demand while GEN Corp. receives no net benefit for producing electricity (i.e., it earns zero net revenue). I argue that when designing fair and efficient electricity markets, it is important to understand the underling incentives of participants.

89. Second, the Amendments do not place DR resources at a competitive disadvantage to non-committed dispatchable generators in the TCA as per AMPCO's assertion. To the contrary, pay DR resources the market price for economic activations would place non-committed-generators at a competitive disadvantage. Through examples, I show that paying DR resources the market price for an economic activation compensates them twice for their demand reduction. This double benefit would allow them to bid lower in the energy market, and offer lower capacity prices in the TCA to the disadvantage of non-committed generators. Furthermore, I demonstrate that DR resources that are Class A consumers already have a competitive advantage over non-committed generators in the TCA since they can avoid paying Global Adjustment as a capacity resource. This later point creates incentives for large-consumers to invest in behind-the-meter generation at a cost greater than the cost to operate and maintain a non-committed generator facility.

90. Third, the Amendment is consistent with the promotion of fair and equitable competition as it provides the proper incentives for DR resources to operate efficiently within the TCA and the IESO's energy market.

91. Fourth, 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 to even further studying the merits of the application of the net benefits test in Ontario.

92. Fifth, Ontario has made significant progress towards reducing the types of barriers to DR resources that concerned the Commission at the time of FERC Order No. 745. In

my opinion, providing DR resources energy payments for economic activations is not required to overcome any legitimate barriers to DR resources, to the extent there are any remaining barriers.

93. With this I conclude my testimony.

SWORN before me at the Town of Paris,)
in the Province of Ontario,)
this 21st day of November, 2019)
)
)
)
A Commissioner for Taking Affidavits) **Brian Rivard**

Lauren Theresa Daniel, a Commissioner, etc., Province of Ontario, while a Student-at-Law. Expires April 8, 2022.

TAB 10

Energy Payments for Economic Activation of DR Resources

October 10, 2019

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History and Context

- Energy payments for the utilization of demand response (DR) resources has been an ongoing topic of discussion at the Demand Response Working Group (DRWG)
- In 2017, the IESO commissioned Navigant to prepare a discussion paper in order to facilitate an informed discussion on the topic. The Navigant paper concluded, in part, that the “arguments for and against utilization [energy] payments are nuanced and prudent. Responsible stakeholders can arrive at different conclusions based on preferences for evaluation criteria” and that “Additional effort is required to estimate the quantum of the impacts”
- The IESO discussed the findings of the Navigant report with stakeholders at the DRWG in 2018 (refer to pre-reading materials)
- Stakeholder interest in energy payments was renewed in early 2019 as a result of the proposed market rule amendments to enable the then “transitional capacity auction”, now “capacity auction”
- Given that this is a complex issue and would be a substantive change to Ontario’s energy market, the IESO determined that a broader stakeholder engagement was needed to advise on the issue

Today's Overview

1. Introductions
2. Engagement plan overview
3. Develop a common understanding of the energy payment issue
   - Q and A on pre-reading materials
   - Review of problem statement
4. Review draft research and analysis scope
5. Break-out discussion on draft research and analysis scope
6. Summary

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Engagement Objectives for Today's Meeting

- Develop a common understanding of the energy payment issue amongst all stakeholders
- Review the high-level proposed approach and schedule for undertaking this work with stakeholders
- Facilitate a break-out discussion to ensure the scope of the research to be conducted considers different stakeholder perspectives

2. STAKEHOLDER ENGAGEMENT PLAN: OVERVIEW AND APPROACH

Stakeholder Engagement Plan

- To be conducted in accordance with the IESO's approved engagement principles
- Draft engagement plan posted for comment on August 22
- Engagement Objective
  - Provide a forum for stakeholders to advise on the research and analysis required to help inform the IESO's decision on whether demand response (DR) resources will be compensated with energy payments for in-market activations.

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Stakeholder Engagement Plan continued

- Feedback from stakeholders is needed on:
  - Inputs and outputs of third-party research and analysis to inform IESO's decision on the energy payment issue
  - Other information that should be considered
  - The IESO's draft decision and rationale on whether DR resources will be compensated with energy payments for in-market activations

Engagement Schedule

August 22, 2019	Engagement launched and Draft Engagement Plan posted for comment
October 10, 2019 *(Today)*	Review engagement plan and objectives Review and gather feedback on draft scope of research and analysis
November 2019	Final study scope and study plan
Q1 2020	Draft research findings and/or analysis for stakeholder review
Q1 2020	Final research findings and analysis
May 2020	Draft IESO decision and rationale for stakeholder review
June 2020	Final IESO decision and rationale

- IESO will be gathering stakeholder feedback throughout the engagement
- Any additional feedback on the draft engagement plan can be submitted to engagement@ieso.ca

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3. DISCUSSION OF THE ENERGY PAYMENT ISSUE AND PROBLEM STATEMENT

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Purpose

- Develop a common understanding of the energy payment issue amongst all stakeholders
- To seek feedback and input on the problem statement that will be answered at the end of this engagement

Overview of the Issue

- Demand Response can be provided in Ontario by dispatchable loads and Hourly Demand Response (HDR) resources
- When a dispatchable load or HDR resource is activated to reduce consumption based on "in-market" signals in the energy market, i.e., when the applicable market price is greater than the resource's energy bid, the DR resource does not currently receive an energy payment for reducing its consumption.
  - Demand Response Market Participants (DRMPs) that have a capacity obligation, awarded through the auction process, must register as either a dispatchable load or HDR resource. The DRMP fulfills its capacity obligation by making such capacity available in the energy market by submitting bids. The energy bid for DRMPs is required to be greater than $100 and less than $2000
  - Dispatchable loads can participate in the energy market with or without a DR capacity obligation
  - A description of how dispatchable loads and HDR resources are activated is described in the slides that follow

Activation of Dispatchable Loads

- Dispatchable loads are activated in the energy market on a 5-minute basis
- In-market activation occurs when the shadow price, a 5-minute price determined by the constrained real-time run of the dispatch algorithm - is greater than the dispatchable load's energy bid price
- Under the current design, the settlement process reconciles any difference between the energy bid and the market clearing price

Activation of HDRs

- HDRs are activated in the energy market on an hourly basis, for a time block up to 4 hours
- In-market activation occurs when the pre-dispatch shadow price at the node – determined through the constrained run of the dispatch algorithm - 3 hours prior to the activation, is greater than the HDR's energy bid price
- HDRs are provided with notice of the activation 2.5 hours before the start of the first dispatch hour to which it relates

Out-of-Market Activations

- HDR resources can also be activated out-of-the market for a capacity test or emergency control action
  - In these cases, the HDR resources can be activated when they are not “in-market”, i.e., even if the pre-dispatch shadow price 3 hours prior to the activation is lower than the resource’s energy bid price
- Compensation for out-of-market activation of HDR resources was recently discussed through the DRWG and is out of scope for this engagement

Establishing a Common Understanding of the Energy Payment Issue

- The following pre-reading materials were circulated in advance to build stakeholder understanding of the issue:
  - Navigant Demand Response Discussion Paper (December 2017)
  - DRWG presentations where the Discussion Paper findings were discussed (January and March 2018)
  - FERC Order 745 as supplementary background
- Do you have any questions, based on the pre-reading materials and concepts described in the earlier slides, to better understand the:
  - Characterization of the energy payment issue; and,
  - Factors considered in the previous work?
- Are there any other materials that should be considered within this stakeholder forum?

Stakeholder Submissions

- Stakeholders are invited to provide their own submissions that help develop an understanding of the energy payments issue for consideration in this engagement
  - Please identify interest in doing so by emailing engagement@ieso.ca by October 25, 2019
  - Submissions are requested by November 13, 2019 so that these materials can be posted and reviewed in advance of the next engagement meeting (November 27, 2019) **dates to be confirmed*
  - Stakeholders will be invited to answer questions on their submissions at the next engagement meeting

The Proposed Problem Statement

Should demand response resources receive energy payments when they are activated in-market?

Definitions

- Where:
  - Demand Response refers to a resource that that is registered with the IESO as either a dispatchable load or HDR
  - Energy Payment refers to a payment for reducing energy consumption that is based on the amount of energy reduced and the applicable market price
  - In-Market Activation refers to the resource being scheduled to reduce consumption when the applicable market price is greater than the resource's energy bid

Feedback on the Problem Statement

- Does the draft problem statement reflect the question that needs to be answered at the end of this engagement? If not, please provide and describe an alternate statement for consideration
- Stakeholders are invited to provide written feedback by October 25, 2019 by e-mailing engagement@ieso.ca

4. DRAFT SCOPE OF RESEARCH AND ANALYSIS

Purpose

- To review the draft scope of research and analysis, which will be used to inform the IESO's answer to the problem statement (discussed as a previous agenda item) and seek stakeholder feedback

Proposed Decision Framework

Problem Statement: *Should DR resources receive energy payments for in-market activations?*

Criteria: *Is there an overall net-benefit to consumers over the long-term?*

Research and Analysis: *will form the basis to which the criteria will be applied (will be supported by the Brattle Group)*

Draft Scope of Research and Analysis

The research and analysis will answer the following questions for both current market and the market design after the Market Renewal Program is implemented (where applicable):

1. **What is the relevant Ontario context and history?**
   - History of DR programs and structures, current levels of DR participation and status quo outlook for future participation
2. **What are the economic first principles that drive the activation decision for demand response resources?**
   - Including: marginal cost of dispatch, wholesale market prices, impact of "retail" rates, impact of activation payments which may or may not apply
3. **How are in-market activations compensated in other jurisdictions and what are the key takeaways for Ontario?**

Draft Scope of Research and Analysis continued

4. **If compensation is provided, what could the compensation model look like in Ontario?**
   - The purpose of this question is to provide the lens through which the benefits, risks and implications can be assessed; it should not be viewed as an indication of the answer / outcome to the problem statement
5. **What are the benefits, risks, and implications of a) the status quo, and b) providing DR with energy payments in the near and longer terms?**
   - Considers impacts on: market and economic efficiency, competition and level of DR participation, cost-recovery, consistency and fairness vis-à-vis other market participants and other indirect impacts

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Stakeholder Feedback on the Criteria and Scope of Research and Analysis

- Feedback on the scope of research and analysis will be collected through the upcoming break-out discussions
- Stakeholders are also invited to provide written feedback, on the following questions, by October 25, 2019 by e-mailing engagement@ieso.ca
  - Is the decision criteria appropriate?
  - What else should be considered in scope of the research and analysis and why?
  - Are there any questions in the scope of the research and analysis that should be refined or removed? If so, why?

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5. BREAK-OUT DISCUSSIONS

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Break-Out Discussions

- The purpose of the break-out discussions is to build awareness of the various perspectives and considerations related to this issue
- The discussion will help identify additions / refinements to the scope of the research and analysis that will be carried out to inform the IESO's decision
- The focus question for the discussion is:

What are the potential pros and cons of providing DR resources with energy payments for in-market activations?

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Break-Out Discussion Logistics

- Break into small groups
- Discuss focus question as a small group (35 mins)
  - Please write key discussion points on flip-chart paper with markers provided
- Report-back key discussion to all (5 mins per group)
  - Elect one presenter to provide the highlights
- IESO will collect, record, and post flip-chart notes on engagement webpage
- Webinar participants are invited to participate in a virtual break-out discussion

Break-Out Discussion Focus Question

What are the potential pros and cons of providing DR resources with energy payments for in-market activations?

6. SUMMARY AND NEXT STEPS

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Summary of Stakeholder Feedback

Feedback Topic	Details
Understanding the energy payments issue	• Stakeholders to signal their intent to provide submissions that help develop an understanding of the energy payments issue
Draft Problem Statement	• Does the draft problem statement reflect the question that needs to be answered at the end of this engagement? If not, please provide and describe an alternate statement for consideration
Decision Criteria and Scope of Research and Analysis	• Is the decision criteria appropriate? • What else should be considered in scope of the research and analysis and why? • Are there any questions in the scope of the research and analysis that should be refined or removed? If so, why?

- All feedback is requested by October 25, 2019
- Please use the feedback form provided on the engagement webpage

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Next Steps

- Next engagement meeting tentatively planned for November 27, 2019
- Scope of this meeting will include:
  - Discussion of consideration of feedback received following today's meeting
  - Discussion of stakeholder submissions
  - Final scope of research and analysis to be carried out

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TAB 11

October 25, 2019

IESO Stakeholder Engagement

Submitted via email

Re: AMPCO Submission – Energy Payments for Economic Activation of DR

AMPCO is the voice of industrial power users in Ontario. Our goal is industrial electricity rates that are competitive and fair.

Attached is AMPCO's submission made in response to the call for input as part of the newly constituted stakeholder engagement dealing with Energy Payments for Economic Activation of Demand Response as part of the IESO's Capacity Auction (formerly known as the Transitional Capacity Auction, and so referenced within this submission for consistency and clarity).

AMPCO appreciates the opportunity to provide such a submission, and looks forward to continuing the dialogue.

Best Regards,

[Original signed by]

Colin Anderson
President

Energy Payments for Economic Activation of DR:

Submissions of the Association of Major Power Consumers in Ontario (AMPCO)

INTRODUCTION

Ontario's electricity system is complex and always evolving. AMPCO provides Ontario industries with effective advocacy on critical electricity policies, timely market analysis and expertise on regulatory matters that affect their bottom line.

These submissions are made in response to the call for feedback issued by the IESO at its October 10 stakeholder session (Energy Payments for Economic Activation of Demand Response Resources). AMPCO's members are major power consumers, responsible for over 15 TWh of annual load in the province. A reliable and affordable energy supply is critical to the success of their businesses, which is why AMPCO has an interest in these discussions and in these discussions.

AMPCO appreciates the opportunity to provide this feedback and looks forward to continued discussions on this topic.

SUMMARY

AMPCO supports energy payments for economic activation of Demand Response. This has been well documented in AMPCO's previous 2019 submissions to the IESO made on March 27, May 2, June 5, July 5, July 9 and July 19 (jointly with AEMA). AMPCO will not reiterate those same comments and arguments here.

However, the pace of the stakeholder consultation constituted to directly address this issue does not match the IESO's speed for the movement of the remainder of the TCA project. Where the TCA project is aggressively moving towards the first auction in December of 2019, the consultation appears to be taking a leisurely stroll, content to revisit previously decided matters and to include within its scope tangential issues that are likely not required to advance the discussions at a reasonable rate.

Accordingly, AMPCO suggests that the IESO more narrowly scope the consultation to deal with ***how*** to implement energy payments (consistent with almost all other FERC and non-FERC jurisdictions, as reported by Navigant in the December 18, 2017 discussion paper commissioned by the IESO)[1], rather than ***if*** to pay them. The consultation could be dramatically streamlined by abandoning the exhaustive review of the FERC decision and all the evidence and argument brought to bear in that exercise, and simply accepting the decision and adjusting it for the relevant Ontario context. It should be remembered that this entire issue was thoroughly debated in front of and decided by the FERC in 2011[2], and the resulting decision upheld by the Supreme Court of the United States in 2016[3]. It seems unlikely that the IESO, in its stakeholder consultation, will do a more comprehensive job than was done by the FERC.

SPECIFIC COMMENTS ON THE OCTOBER 10 STAKEHOLDER SESSION

1. Proposed Problem Statement

   The proposed problem statement is too broad, for the reasons set out above. AMPCO suggests the following:

   "When Demand Response resources are economically activated, they will be compensated for the service provided to the energy market at the market price for energy, provided they have the capability to balance supply and demand as an alternative to a generation resource and when dispatch of that demand response

[1] http://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Energy-Payments-for-Economic-Activation-of-DR-Resources
[2] https://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf
[3] https://www.supremecourt.gov/opinions/15pdf/14-840-%20new_o75q.pdf

resource is cost-effective as determined by the net benefits test. How should a net-benefits test be constructed in Ontario to ensure cost-effectiveness?”

2. Proposed Criteria

   The IESO has proposed the following criteria to guide the decision framework:

   “Is there an overall net benefit to consumers over the long term?”

   In AMPCO’s submission, this is inadequate. The criteria dealing with the net-benefits test should be framed consistent with FERC Order 745. If the problem statement is modified consistent with AMPCO’s recommendation above, no other criterion is necessary. However, if the scope of this consultation is maintained in its current broad form, then an additional criterion is required ensuring that the treatment afforded Demand Response resources pursuant to the TCA, or any other capacity auction, is fair and non-discriminatory in nature.

3. Scope of Research and Analysis

   The scope of the research and analysis should be revised to reflect the recommended problem statement. Many of the items shown in the IESO’s October 10 presentation materials (at slides 23 and 24) are unnecessary if the scope of the consultation is narrowed. Many of these items will already have been considered pursuant to the FERC proceeding, and other engagements such as the Navigant discussion paper dated December 18, 2017.

There is no need to reinvent the wheel in this consultation, and by streamlining the problem statement, the criteria and the scope of the analysis, a conclusion can be reached in a much more timely fashion.

TAB 12

Energy Payments for Economic Activation of Demand Response Resources

Comments on the Stakeholder Engagement Plan presented on October 10, 2019

Don Dewees

Market Surveillance Panel

18 November 2019

On October 10, 2019, the IESO presented its stakeholder engagement plan to determine whether it will provide energy payments to Demand Response (DR) resources when they are economically activated. The IESO invited stakeholders to provide comments on the scope of the analysis to be undertaken by a third party and any insights or analysis on the appropriateness of providing energy payments to DR resources. The Market Surveillance Panel (MSP) appreciates the opportunity to submit comments.

1. What are the objectives of providing energy payments to loads?

The study should provide one or more objectives that might be achieved by providing energy payments to loads. It is not clear what role energy payments for DR resources would promote – i.e. for spare energy, greater system flexibility, increased participation in the energy market or emergency response, among others. In contrast, FERC Order 745 – in which the U.S. regulator ordered system operators to provide energy payments to DR resources – provided a clear objective that it was attempting to achieve. In that Order, FERC argued that providing energy payments would help "remove barriers to participation of demand resources" in the wholesale market, among other benefits.[1] FERC stated that its aim was to increase the participation of DR resources in the wholesale market. However increased participation, in itself, is not an appropriate goal. Would increased participation lead to increased market efficiency, greater reliability, lower costs or more effective competition? The consultant should identify the objectives of using DR in the Ontario market and assess the ability of energy payments to promote these objectives in a manner consistent with the principles governing the Ontario market. Similarly, it can review whether the objectives and outcomes should be applied equally to Dispatchable Loads and Hourly Demand Response (HDR) resources, given their distinct characteristics.

It is not clear whether the Order 745 approach is necessary in the wholesale market in Ontario. The MSP notes that a number of DR resources already participate in the wholesale market as Dispatchable Loads. HDR resources also participate in the wholesale market via bidding and many loads currently pay the wholesale price for energy, not a retail rate as is common in the U.S. markets. Loads not paying the wholesale price was seen as a barrier to fully participating in the wholesale market in Order 745. The study should determine what market benefit, if any, would be achieved by expanding energy payments to loads, as it is not evident that the stated goal laid out in Order 745 is appropriate or necessary in Ontario. In the present situation, a DR resource that is activated saves the spot price on its demand reduction, analogous to a generator being paid the spot price for its production. On this basis, an energy payment to DR resources looks like double payment. A number of stakeholders appear to be urging the IESO to accept Order 745 as the definitive ruling on this issue, but the Ontario situation is different and we may not share the same objectives as FERC.

[1] https://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf

2. What principles will be used to evaluate energy payments for DR resources?

The study should also identify the core principles it will rely on when evaluating whether to provide energy payments to DR resources. In its Market Renewal Program (MRP), the IESO laid out five core principles that would guide the program – efficiency, competition, implementability, certainty and transparency. The principles applied to making energy payments to DR resources should be consistent with the principles applied to the Ontario electricity market in general.

3. Are energy payments necessary to achieve those objectives and principles?

Once the study has articulated its objectives and the principles that will be applied, it can determine if energy payments to DR resources are necessary. As it currently stands, the IESO appears to be asking stakeholders – many of which would benefit from energy payments – to provide reasons why it should or should not provide energy payments, with 'increased participation' appearing to be a goal without assessing the costs and benefits of such an increase. The consultant should assess the costs and benefits of energy payments that might increase participation and determine the net impact that mere "increased participation" would yield.

TAB 13

TABLE OF CONTENTS

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PART I - INTRODUCTION

1. The Independent Electricity System Operator's ("**IESO**") Board of Directors ("**IESO Board**") approved MR-00439-R00 to R05 (the "**Amendment**") enabling the IESO's Transitional Capacity Auction (**"TCA"**) on August 28, 2019, with an effective date of October 15, 2019.

2. The Amendment is a first step in broadening and increasing competition in the IESO's capacity auction and addressing a forecast summer 2023 capacity gap of approximately 4,000 MW.

3. As further explained herein, the IESO opposes the Association of Major Power Consumers in Ontario (**"AMPCO"**) Application request that the Amendment be revoked, and the TCA be suspended, until such time as the IESO amends other market rules to provide for energy payments to demand response (**"DR"**) resources in the energy market. It is the IESO's considered opinion that:

(a) It is important for reliability purposes to launch the TCA in December 2019 and to progress the TCA in a phased manner which provides the IESO and TCA participants the opportunity to learn and, as necessary adapt, in advance of the forecast 2023 capacity gap. It is the IESO's view that it would be imprudent, risking future reliability, to delay the TCA and launch it closer to the eve of the 2023 capacity gap;

(b) The TCA will provide an opportunity for existing non-committed generators coming off contract, which may in the absence of the TCA choose to wind down their operations to the potential detriment of Ontario reliability and the interests of Ontario consumers; and

(c) The TCA will increase competition and benefit consumers by allowing for participation by new capacity resource types and increasing the supply of capacity into the auction.

4. The IESO disagrees that AMPCO's members or other DR resource participants will be materially harmed, let alone unjustly discriminated against, by proceeding with the TCA prior to resolving the issue of energy payments for DR resources. No DR

participants who participated in the Demand Response Auction ("**DRA**") have provided any evidence of potential harm. Further:

(a) AMPCO is requesting a fundamental change to Ontario's energy (not capacity) market design and market rules by proposing energy payments for loads and this issue is very complex, particularly in the context of Ontario's hybrid electricity market, and warrants necessary study and analysis. The IESO has prioritized the concerns of AMPCO members by undertaking a comprehensive stakeholder engagement and third party study on energy payments for DR resources, which will be completed in Q2 2020 following which the IESO will make a final determination and, as necessary, initiate market rule changes.

(b) There will be no harm, or negligible harm, to DR resources in the interim. DR participants in the DRA have rarely been economically activated in the energy market and the IESO does not anticipate any material increase in DR activations over the period governed by the December 2019 TCA. DR participants will also be compensated for out-of-market activations, which is their only material exposure to activation.

5. The IESO is pleased to submit to the Board its written evidence, which is presented below in question and answer format.[1]

PART II - LEGAL AUTHORITY

A. Who is the IESO?

6. The IESO is a public agency, that is continued under the *Electricity Act, 1998*, S.O. 1998, c. 15, Sched. A (the "***Electricity Act***") and its responsible for maintaining the reliability of the provincial transmission grid, administering Ontario's wholesale electricity market and planning the province's bulk power system.

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[1] Much of the evidence contained herein overlaps with and relies on the Affidavit of David Short, sworn on October 25, 2019, which the IESO submitted to the Board in response to AMPCO's Motion to Stay the operation of the Amendment. For coherence, we have reproduced portions of the said affidavit herein.

7. The IESO's authority under Part II of the *Electricity Act* includes making market rules: (1) governing the IESO-controlled grid; (2) establishing and governing markets related to electricity and ancillary services; and (3) establishing and enforcing standards and criteria relating to the reliability of electricity service or the IESO-controlled grid.

B. What is the IESO's process to amend the market rules?

8. The IESO's Board has ultimate authority and responsibility to amend market rules.

9. The IESO has developed a stakeholder engagement processes to consult with individuals and organizations for the purpose of informing the IESO's decision-making, including proposed market rule amendments. The IESO's stakeholder engagement processes are designed to promote transparency, efficiency and consistency.[2]

10. All proposed market rule amendments are considered by the IESO's Technical Panel, whose members are appointed by the IESO Board of Directors. The IESO's Technical Panel is composed of stakeholders that represent a broad range of electricity resources and constituencies in the IESO-administered markets. The Technical Panel provides advice to the IESO Board on proposed market rule amendments.

11. Each member of the Technical Panel casts a vote as to whether they are in favour of, or opposed to, proposed rule amendments along with the reason for their position. This information is then communicated to the IESO Board for its consideration in determining whether to approve proposed market rule amendments.

12. After the IESO Board has adopted or rejected a proposed amendment, information on the Board's decision with reasons is posted to the IESO's public website along with the approved amendments as applicable.

13. The IESO is also required to provide a copy of any adopted amendment, along with prescribed information, to the Board before the IESO publishes the amendment and the Board may, not later than 15 days after the amendment is published, revoke the amendment.

[2] The IESO guides its engagement processes in accordance with its Engagement Principles to ensure that the engagement activities follow an efficient and effective process which is conducted with integrity. Attached at **Tab "1"** are the IESO's Engagement Principles, undated.

PART III - THE TRANSITIONAL CAPACITY AUCTION

A. What is the Transitional Capacity Auction?

14. The purpose of the Amendment is to implement the TCA in Ontario. The TCA is the first step in evolving the IESO's existing capacity auction – the demand response auction ("**DRA**") – into a more competitive capacity auction that includes additional resource types and enhanced auction features that will improve reliability. The DRA was limited to dispatchable load and hourly demand response ("**HDR**") resources. The Amendment enables non-contracted and non-regulated dispatchable Ontario generators to participate in a capacity auction alongside dispatchable loads and HDR resources.

15. The Amendment largely leaves the foundation of the DRA in place and begins the transition to a broader capacity auction by expanding eligibility to participate in the TCA to resource types other than DR resources.

B. What does capacity mean in the context of the IESO-administered market?

16. In the context of the IESO-administered markets, "capacity" represents the need to have sufficient resources available to ensure that the demand for electricity in Ontario can be met at all times.

17. At a high level, capacity can be provided by supply resources through energy injections or from loads in the form of demand response.

C. What is the IESO's plan for the TCA?

18. The TCA is the first step in evolving the DRA into a more competitive capacity auction that includes additional resource types and enhancing auction features that will improve reliability. Whereas in the past, most capacity in Ontario has been procured through long-term contracts, the TCA will be a market-based mechanism for securing needed incremental capacity.

19. The TCA will run on December 4, 2019 for a one-year commitment period of May 1, 2020 to April 30, 2021. The commitment period will consist of two seasonal obligation periods.

20. The successful participants in the TCA auction will be required to become authorized as Capacity Market Participants, which will enable them to register resources with the IESO to deliver on their capacity obligations. TCA participants will receive availability payments for providing auction capacity, subject to non-performance charges.

21. Following the TCA, the IESO is planning subsequent phases of its capacity auction design that will enable additional resource types to participate (such as imports and storage) and will introduce new auction features to improve reliability and market efficiency. Each phase is expected to require further changes to the market rules.

22. The IESO plans to increase the forward period[3] for future capacity auctions. The IESO's intention is to run future capacity auctions in June 2020 (for a May 1, 2021 to April 30, 2022 commitment period), December 2020 (for a May 1, 2022 to April 30, 2023 commitment period) and in 2021 (for a May 1, 2023 to April 30, 2024 commitment period).

PART IV - THE DEMAND RESPONSE AUCTION

A. What is demand response?

23. Demand response refers to the change in end-user electricity consumption patterns due to fluctuating market prices. DRA participants who are called upon by the IESO provide capacity by refraining from consuming energy from the IESO-administered grid rather than, as in the case of generators, supplying energy to the grid.

B. What is the DRA?

24. The IESO introduced the DRA in 2015 as a means of securing demand-side capacity for the IESO-administered grid. The DRA differs from former Ontario Power Authority (**"OPA"**) DR programs in that it is a market-based program administered under the market rules and DRA participants are integrated into the IESO-administered market, as opposed to the former OPA contract based DR programs.

[3] A forward period is the time between the execution of the auction and the first day of the commitment period.

25. DR participants in the DRA (**"DRA participants"**) participate in the energy markets either (1) dispatchable loads that responds to a five-minute schedule, or (2) as Hourly Demand Response (**"HDR"**) participants where participation limited to hourly blocks (up to 4 hours per day) with activation notice required at least two hours in advance of the need.

26. The DRA procures capacity for (1) a summer commitment period which occurs from May 1 to October 31 and (2) a winter commitment period which occurs from November 1 to April 30.

C. What are the mechanics of the DRA?

27. DRA participants are required to submit offers in the DRA for quantities between 1 MW and the DR capacity for which they were qualified in the DRA pre-auction process and are allowed to use offer laminations reflecting the prices of providing various levels of capacity. The prices offered must represent the minimum prices at which the participant is willing to provide each incremental quantity of capacity.

28. DRA participants must be willing to provide DR capacity – by reducing their consumption – starting on the first day of the commitment period, failing which they are subject to non-performance charges.

29. After DRA participants submit their offers, the offers are stacked against the demand curve to determine the clearing price for each zone and for each commitment period. The process of determining the auction clearing price is summarized in Market Manual 12.0.

30. After running the auction, the IESO communicates a Public Post-Auction Report to the public and a private Post-Auction Participant Report to market participants.

31. All successful DRA participants in a zone receive the same availability payment per MW day for their capacity obligation. This is referred to a "price as cleared"[4] where all successful participants are paid the same availability payment. As such, assuming resources offer into the auction at or near their costs, lower priced resources would

[4] *Price as cleared* is a standard auction and energy market mechanism where all successfully scheduled resources are essentially paid the highest price for that zone.

receive more profits as compared to resources that clear near the final auction price. Typically a number of auction participants are not price competitive, do not clear the auction and do not receive an obligation to supply capacity.

32. DRA participants who have incurred a DR capacity obligation through the DRA receive a monthly payment for every month of the commitment period for being available to supply capacity if called upon (referred to as an availability payment).

D. How are DRA resources activated or called upon?

33. All DRA resources are expected to be available to reduce their consumption during the summer commitment period from 12:00 to 21:00 EST, and during the winter commitment period from 16:00 to 21:00 EST.

34. Dispatchable load resources are activated (dispatched automatically by the IESO's Dispatch Scheduling Optimization software) on a 5-minute interval if the bid in the energy market is economic, either to meet Ontario's provincial need or a local energy need.

35. HDR resources have restrictions on their ability to be reduce consumption so they require a standby notice from the IESO at any time between 15:00 EST day-ahead up to 07:00 EST on the day of. HDR resources that are on standby can then receive an activation at least two hours in advance for one to four hour hourly blocks of reduced consumption – and only if they are economic compared to other resources for the hour(s) they are activated. HDR resources can only receive one activation per day.

E. What's the frequency for the activation of DR resources under the DRA?

36. DRA participants have been activated in the energy market in very limited circumstances since the DRA was launched in 2015. This is likely due to the relatively high prices at which DRA participants have bid into the energy market.

37. During this period, the Hourly Ontario Energy Price (**"HOEP"**) has averaged approximately $25/MW. During the same period, dispatchable load bid prices have averaged approximately $1500/MWh and HDR bid prices have averaged approximately $1700/MWh.

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

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[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.

generators receive energy payments, but loads do not. Dispatchable loads bid prices in the energy market represent the point at which the load does not wish to consume electricity.

C. Did DR resources receive energy payments under the former OPA programs?

44. No, they did not. Starting in or about 2005 the former Ontario Power Authority (**"OPA"**) commenced a number of demand-side programs. The OPA held yearly procurement processes in which qualified participants bid for contracts to curtail their electricity consumption during periods of high system demand. These programs paid participants a monthly availability payment in return for the commitment to reduce load when called upon.

45. The final OPA DR program, called the Demand Response 3 (**"DR3"**) program, included utilization payments for activations. These payments, however, were not energy payments. They were contract payments set at a fixed rate of $200/MWh.

46. After the merger of the OPA and IESO on January 1, 2015, the IESO developed a transitional demand response program, governed by the market rules, called the Capacity Based Demand Response (**"CBDR"**) program. The CBDR program bridged the period from the DR3 contract expiration to the commencement of the DRA. For this period, the CBDR program continued some of the features of the DR3 program for the purpose of facilitating the transition to the DRA market-based structure under the market rules. For instance, the fixed rate $200/MWh utilization payment was included in the CBDR program until the expiration of DR3 contracts.

D. Do DRA participants receive energy payments?

47. No, they do not. As stated above, under Ontario's market design and the market rules, only generators are entitled to energy payments. DRA participants are solely entitled to monthly availability payments for the duration of their applicable commitment periods.

E. Will TCA DR participants receive energy payments?

48. No, the Amendment does not change the market rules governing payments in the IESO energy market. DR participants in the TCA will not receive an energy payment in the energy market because, as detailed above, loads are not entitled to receive energy payments under the market design and the market rules that have been in place since market opening.

F. Has the IESO previously studied the issue of energy payments for DR Resources?

49. Yes, the IESO previously commissioned a study of the merit of utilization payments for DR resources through its Demand Response Working Group ("**DRWG**").[7]

50. In the lead up to the launch of the DRA, some stakeholders had inquired about energy payments or utilization payments in the DRA, however, the immediate priority was to implement the DRA.

51. In early 2017, some DRWG members again raised this issue on the basis that "[o]ther jurisdictions (ISO-NE, NYISO, PJM) provide both energy and availability payments to DR [resources]" (p. 19). The IESO therefore agreed to further look into this matter (p. 22).[8]

52. In July 2017, the IESO, in consultation with the DRWG, engaged Navigant, an independent consultant with expertise in DR and electricity markets, to study and prepare a discussion paper on the merits of utilization payments.[9] Stakeholders were invited to provide submissions to inform the scope of Navigant's analysis, which included:

(a) Jurisdictional review - A summary of practices adopted in other markets;

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[7] The IESO established the DRWG in April 2014 to assist in the evolution of DR from a contracted resource into the energy market, as well as to inform the development of pilots and the DRA stakeholder engagement.

[8] Attached at **Tab "4"** is *DR Stakeholder Priorities for 2017*, Demand Response Working Group, dated January 31, 2017**.**

[9] Attached at **Tabs "5", "6", "7"** respectively are *Utilization Payments for DR Activations*, Demand Response Working Group, dated May 11, 2017; *Utilization Payments – 2017 Work Plan Item*, Demand Response Working Group, dated May 30, 2017; and *Utilization Payments – 2017 Work Plan Item*, "Scope of Discussion Paper", dated July 21, 2017.

(b) Economic efficiency - Arguments for/against providing utilization payments to DR resources in light of current and future system needs;

(c) DR Participation – The likely impacts of utilization payments to the dispatch frequency of HDR resources in Ontario;

(d) Wider market impacts - Spillover effects on the wider market.

G. What were the findings of the Navigant study?

53. On December 19, 2017 the IESO published a discussion paper by Navigant (the **“Navigant Paper”**)[10] which, among other things, presented arguments for and against utilization payments, as summarized in the table below:

Arguments against utilization payments	
Wholesale Price Efficiency	Real-time wholesale prices are an efficient price signal because they match supply and demand based on bids and offers on a minute-by-minute, and hour-by-hour basis, and introducing an additional payment could create an inefficacy in the market because dispatchable loads would receive an out-of-market payment that could alter their bid/offer strategy. In Ontario, this argument applies to loads that receive the wholesale energy price.
Disproportional Benefits	Providing a utilization payment compensates a DR resource disproportionately relative to a supply resource because the DR resource does not incur a cost associated with the production of electricity. Therefore, a DR resource should be treated as if it had first purchased the power it wishes to resell to the market. This argument is based on the premise that the value of a megawatt of electricity curtailed (a “negawatt”) is not equivalent to a megawatt of electricity, and assumes that the cost of curtailment for a DR resource is immaterial.
Harm to Other Suppliers	Utilization payments will result in downward pressure on wholesale prices because DR resources are able to bid into the energy market at prices lower than traditional supply and will be dispatched more frequently. However, in Ontario, to have a material impact on capacity or energy prices, utilization payments would have to result

[10] Attached at **Tabs “8”, “9”** respectively are Navigant, *Demand Response Discussion Paper* (the “***Navigant Paper***”), dated December 18, 2017; and Navigant Demand Response Discussion Paper (Presentation to DRWG), dated November 16, 2017.

	in a considerable increase in levels of participation and activation Under the current market structure in Ontario, most generators are under contract or receive regulated rates and hence consumer costs are largely fixed.
Harm to Economy	Utilization/energy payments will incentivize loads to reduce production to provide demand reductions into the electricity market, reducing the supply of other goods in the economy and increasing prices.
Arguments for utilization payments	
Reducing Consumer Costs	Utilization payments will increase the level of DR participation and activation, which is a less expensive form of capacity and energy than traditional supply resources, and hence will result in lower consumer costs
Disconnect Between Wholesale and Retail Prices	Retail prices do not reflect the real-time fluctuations in the cost of electricity and are inefficient and utilization payments are a way of improving the economic efficiency of the retail price by providing an additional financial incentive during high-price events. However, this argument is only valid for customers on retail rates and not exposed to real-time energy prices.
Fairness	Generation resources receive a utilization payment in the form of an energy payment when they produce electricity and DR resources should be treated fairly and receive a utilization payment when they curtail electricity. The argument is based on the FERC Order 745 which requires that the energy payments result in a *net benefit* to consumers. However, this argument is based on the assumption that, in Ontario, a megawatt of electricity curtailed (negawatt) is equivalent to a megawatt of electricity.
Other Costs Associated with Curtailment	There is a cost associated with curtailing demand (or producing a negawatt of electricity), which is equal to the value of lost load, which can be higher than the avoided cost of electricity, utilization payments compensate DR resources for these costs. However, for large commercial and industrial customers, the value of lost load can be very high, which could result in limited activation of DR resources regardless of whether utilization payments are offered.

54. In its conclusion, Navigant commented on the complexity of the matter and also expressed doubt on whether the benefits associated with energy payments to demand resources in other markets would apply in Ontario:

> The arguments for and against utilization payments are nuanced and prudent. Responsible stakeholders can arrive at different conclusions based on preferences for evaluation criteria.
>
> A unique consideration for Ontario is that today, almost all generation resources are compensated under long-term contract or through regulation that guarantees a certain level of revenue. The economic efficiency arguments under this current market structure are different than they would be if considering the future state of the wholesale power market where generation resources are largely compensated through energy and capacity market revenues. Under the current conditions, more DR activation (as a result of bidding into the market at prices lower than traditional generators) would not actually lead to reduced costs to consumers since generators have their compensation guaranteed (section 3.2).

H. What was the feedback from DRWG members to the Navigant Paper?

55. The IESO encouraged DRWG members to review, ask questions and provide feedback about the Navigant Paper.[11]

56. In early 2018, the DRWG convened to continue discussion on Navigant Paper and the issue of utilization payments in the DRA.[12] The IESO responded to feedback from the DRWG members which generally fell into three categories: (1) impact on utilization; (2) fairness; and (3) market efficiency:

(a) The IESO addressed stakeholder comments that utilization payments would incentivize residential DRA participants to bid lower energy prices, which could increase utilization (p. 5). The IESO acknowledged that in

[11] Attached at **Tabs "10", "11", "12"** respectively are IESO, *Communication to DRWG Members,* dated December 19, 2017; *Utilization Payment Discussion Paper*, Demand Response Working Group (Presentation), dated January 30, 2018; and IESO, *Communication to DRWG Members*, dated February 12, 2018.

[12] Attached at **Tabs "13", "14"** respectively are *Utilization Payments Discussion*, Demand Response Working Group, dated March 1, 2018 (**"*DRWG Presentation of March 1, 2019*"**); Demand Response Working Group, *Meeting Notes – March 1, 2018*, dated April 5, 2018.

theory this could incentivize participants to lower energy bid prices, which could lead to increased utilization of DR resources. However, the IESO observed that stakeholder feedback indicated utilization payments might not lead to increased utilization.

(b) The IESO addressed stakeholder comments that under the former Capacity Based Demand Response ("**CBDR**") regime, CBDR resources were prepared to be activated at $200/MWh provided they received this payment demonstrating that revenue is a strong incentive for activation (p. 7). The IESO responded that the historical contracting programs required DR energy bids to be priced at $200/MWh. Once the $200 price requirement was removed for HDR resources, the IESO observed that the majority of DR bids were priced by participants much higher than $200/MWh. This phenomenon implied that that DR participants' value of energy consumption was much higher than this level.

(c) The IESO addressed stakeholder comments that if paying a DR resource for utilization reduces the cost of electricity, then DR payments are a positive system benefit (p. 8). The IESO acknowledged that if DR utilization payments could reduce total system costs then it would yield a positive system benefit. However, the IESO observed that on balance, it was not clear that there would be a positive system benefit. Even if providing a utilization payment might reduce the energy price of electricity for that event, other system costs such as uplift and capacity costs would increase.

(d) The IESO addressed stakeholder comments that DR utilization payments based only if "negawatts" and megawatts are functionally and economically equivalent (pp. 10- 14). The IESO provided some illustrative examples where resources could receive additional payments – creating an unequal treatment depending on the configuration of the capacity contribution.

I. Did the IESO reach any conclusions after the publication of the Navigant Paper?

57. No, the IESO did not come to any definitive conclusions on this issue. After further consultation with stakeholders, the IESO, however, did offer the following observations as part of March 1, 2018 presentation to DRWG members:

(a) It appears that the current practice for compensating DR utilization is equivalent treatment and a DR utilization payments would introduce non-equivalent treatment;

(b) There was no clear indication that utilization payments would increase activation for most load types;

(c) For resources exposed to market prices, further discussion did not appear to be merited; and

(d) For resources not exposed to market pricing, the IESO did not see merit in continuing discussion on utilization payments - however, the IESO expressed uncertainty regarding the impact of utilization payments on these type of participants and the IESO requested more input from stakeholders;

(e) Based on the quantity of stakeholder feedback received, the IESO did not see a strong interest from the DRWG on the topic of utilization payment. Only two members submitted feedback on and members declined to present their views for discussion at the DRWG.[13]

58. The issue of utilization payments for DR resources in the DRA ceased to be a priority item for the DRWG after the spring of 2018.

PART VI - THE NEED FOR THE TCA

A. Why did the IESO decide to evolve the DRA into the TCA?

59. As part of its Market Renewal initiative, the IESO had been planning an Incremental Capacity Auction (**"ICA"**) to address Ontario's future incremental capacity

[13] *DRWG Presentation of March 1, 2018*, pp. 16-18

needs. The ICA, which was to be a competitive auction open to participation by a broad range of supply and demand resources, was intended to replace the DRA. The IESO planned to launch the ICA in 2022.

60. On September 13, 2018 the IESO released an updated Electricity Planning Outlook that forecasted a capacity deficit in summer 2023 of 3844 MW (p. 51).[14] Shortly after this, the IESO came to the realization that it was not feasible to launch the ICA in time to address the projected 2023 capacity gap (the **"2023 capacity gap"**) and that alternative measures were required.

61. The IESO determined that the best solution for addressing the 2023 capacity gap was to evolve the DRA into the TCA, for reasons which included the following:

(a) the DRA was directionally aligned with the ICA in that there would be a demand curve based auction that would be executed at regular intervals for a future one-year long capacity need (with two 6-month seasonal periods);

(b) the DRA was a proven mechanism governed by an existing set of market rules;

(c) the DRA provided a platform that could be incrementally evolved into a broader-based and more competitive capacity auction, which would provide the IESO and market participants with opportunities to learn, adapt and make improvements; and

(d) a TCA was preferable to contractually procuring new capacity, which was a less flexible mechanism and risked higher costs for consumers.

62. The IESO also determined that the TCA would provide opportunities for existing off contract generators, which might otherwise decide to wind down their operations to the potential detriment of Ontario reliability and the interests of Ontario consumers. In particular, the IESO was concerned with the risk of permanently losing these existing generation facilities and not having them available when the 2023 capacity gap

[14] Attached at **Tab "15"** is a Technical *Planning Conference Presentation*, dated September 13, 2018, p. 51.

emerged, since these facilities may be able to more cost-effectively satisfy future capacity gaps compared to other alternatives, including the construction of new generation facilities. In addition, these existing resources offer an additional measure of certainty as compared to unknown future alternatives.

63. The TCA was also established to enable the future participation of capacity imports from other jurisdictions. Capacity imports are likely to play an important role in the future and the TCA would establish auctions as a credible and certain mechanism that would entice economic external resources to supply capacity to Ontario.

B. Can the IESO rely upon the DRA to fill the forecast 2023 capacity gap?

64. The IESO cannot rely upon the existing DRA to provide sufficient capacity to satisfy the 2023 capacity gap.

65. The DRA in December 2018 attracted a qualified capacity of over 1000 MW. This is insufficient to meet the 2023 capacity gap, which is now forecast at approximately 4000 MW.[15]

66. HDR resources have also had a history of poor performance during test activations. Between February 2018 and January 2019, HDR resources had a 58% failure rate for test activations which were four hours in duration.[16] These results suggest that the actual capacity available to the IESO under the DRA may be substantially less than the results of prior DRA auctions suggest.

67. HDR resources, which comprise the large majority of DRA participants, are also, unlike dispatchable generators or loads, not dispatchable on a five-minute basis. This presents operability and reliability challenges as compared to relying on capacity from supply or dispatchable load resources. Given the IESO's need to maintain a diverse supply mix of resources to meet system needs, both HDR and DL resources are part of the total solution in meeting Ontario's capacity needs – mixed with other resources that

[15] Attached at **Tabs "16" "17" "18"** respectively are the Stakeholder Advisory *Committee Presentation*, August 14, 2019, p.4 (**"*SAC Presentation*"**); and North American Electronic Reliability Corporation, *2018 Long-Term Reliability Assessment*, dated December 2018 (**"*NERC Report*"**); Northeast Power Coordinating Council, *2018 Ontario Comprehensive Review of Resource Adequacy* (Issue 3.0), dated December 4, 2018 ("***NPCC Report*"**).

[16] Attached at **Tab "19"** is the *Hourly Demand Response (HDR) Testing Update*, dated April 25, 2019.

can be scheduled on a 5-minute or hourly interval both inside and outside of Ontario. The IESO could not assure reliability if all the 2023 and beyond capacity came from only one resource type – diversity in fuel supply and operating characteristics are needed to maintain reliability.

C. Is the IESO still forecasting a capacity gap in summer 2023?

68. Yes, there continues to be a significant 2023 capacity gap that must be addressed by the IESO to ensure the reliability of Ontario's electricity system.

69. This gap has been recognized by the Northeast Power Coordinating Council (**"NPCC"**) and the North American Reliability Corporation ("**NERC"**),[17] with which the IESO is required to report annually on the state of reliability of Ontario's electricity system, including resource adequacy. The assessments are based on NERC and NPCC planning criteria to ensure a consistent approach to reporting and evaluation of the broader regional and continent-wide power system reliability.

70. There are inherent uncertainties with any planning projection. Ontario's extensive nuclear refurbishment and retirement schedule contributes to the capacity gaps in the near-term as the fleet is readied life-extending work or shutdown. As noted in the NERC Report, "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" (p. 15, *Figure 1.5*)".

71. In a presentation to the IESO's Stakeholder Advisory Committee dated August 14, 2019, the IESO provide an updated forecast of a capacity gap of approximately 4000 MW in summer 2023. [18] This is the IESO's most up-to-date forecast.

D. Why is it necessary for the IESO to proceed with a phased implementation of the TCA?

72. The introduction and implementation of the TCA, and subsequent capacity auction phases, is complex and challenging. The IESO has never before undertaken a capacity auction which includes supply resources. The IESO is accordingly initiating this

[17] See *NPCC Report; NERC Report.*

[18] *SAC Presentation*, p. 4.

process gradually and incrementally by, at the outset, only including off-contract dispatchable generation facilities. Thereafter, subsequent capacity auctions will include and add new resource types and broaden resource eligibility criteria. New resource types are anticipated to include storage, system-backed imports, resource-backed imports and self-scheduling generation facilities. Resource eligibility criteria may also be broadened to include, for example, surplus or uprated capacity (i.e. merchant capacity) at existing contracted facilities.

73. These changes will present new requirements and pose additional challenges. For instance, the addition of system-backed and resource-backed imports will necessitate negotiating operating agreements procedures with other independent system operators (**"ISOs"**) and addressing other jurisdictional issues. Likewise, rules governing the participation and compensation of imports must be tailored to reflect the unique operating features of different import types. These differences introduce complexity to the potential participation of imports in the capacity auction and energy market.

74. In addition to the introduction of new resource types and new eligibility criteria, each capacity auction phase, beginning with the TCA, will introduce modified design elements, including capacity qualification criteria, testing and audit requirements, connection assessment criteria, market power mitigation parameters, auction parameters, etc. For instance, introducing new qualifications of capacity will require the IESO to assess each resource's offering into the auction prior to the auction's execution. The intent is to better align the auction results with the IESO's system planning assumption; however, the new process may change a participant's offer strategy and ultimately the auction outcome.

75. In addition to known and foreseeable challenges, there are potential unforeseen consequences. The IESO knows from experience that major new market changes and programs invariably have unforeseen implications and consequences affecting market efficiency or reliability that will need to be addressed through market rule and market manual amendments, and possible tool changes.

76. Due to the complexities of creating an enduring capacity auction, it would be impractical and imprudent to attempt to introduce the full suite of changes required in a

single step, or closer to the eve of the 2023 capacity gap which the TCA is required to address. Progressing in a phased approach, as the IESO has planned, allows the IESO to:

(a) introduce new resource types into the auction gradually;

(b) assess and respond to how new resource types behave in the capacity auction;

(c) provide participants with an opportunity to develop and test business processes and business models to support their participation in capacity auctions;

(d) provide participants an opportunity for price discoverability;

(e) ensure that committed capacity resources are capable of satisfying their capacity obligations;

(f) provide sufficient time to assess and evolve auction design features, informed by stakeholder input;

(g) allocate the necessary resources to implement new auction design features in manageable steps; and

(h) monitor and identify unforeseen consequences arising from new auction design features.

77. There are only three planned auctions (December 2019, June 2020 and December 2020) before the IESO undertakes the auction for the critical summer 2023 period. This provides for limited opportunities for the IESO to execute, learn from and evolve the TCA prior to 2023. The IESO, as the Province’s reliability authority, is not willing to forgo the important opportunities, experience and learnings that these auctions, each with a year long commitment period, provides and which are critical to implementing a capacity auction mechanism to prudently and cost-effectively address Ontario’s future capacity needs.

PART VII - THE IMPLEMENTATION OF THE TCA

A. When did the IESO announce its decision to proceed with the TCA?

78. On January 28, 2019, Peter Gregg, the president and CEO of the IESO, announced that the IESO's plan to expand the DRA to include generators in order to meet immediate resource adequacy needs in Ontario:

> This transition to a capacity auction will start to take shape later this year. As you know, in September we produced a new planning report which indicated a potential capacity gap emerging in 2023. This gap would emerge at a time when Pickering units are closing, as nuclear refurbishments are underway and as some of our generation contracts expire.
>
> While the forecasted gap is relatively small at the moment, our ability to continue to rely on existing resources such as conservation, could affect both the timing and the size of any potential gap.
>
> …[W]e expect to have a clearer picture of our more immediate capacity needs in the third quarter of this year.
>
> We will meet those capacity needs by leveraging the competitive mechanisms we have in place right now such as the annual demand response auction.
>
> […]
>
> In December, we will run an auction to meet capacity needs for 2020. Our goal is to have that auction and subsequent auctions build on the current demand response auction including allowing more resource types to compete. This would provide generators whose contracts are expiring over the next few years an opportunity to compete in our electricity market and help meet emerging capacity needs. It is a staged approach to a much more competitive marketplace … one that we at the IESO and others are striving for. It allows us to realize efficiency, competition and transparency … the key principles of our market renewal efforts – as quickly as possible.

> It's also a sensible approach, allowing both the IESO and market participants to continue to learn and improve our processes as capacity needs increase[19].

B. What stakeholder engagement did the IESO undertake on the TCA?

79. In February 2019, the DRWG convened to discuss the IESO's plan to evolve the DRA to meet Ontario's capacity needs after 2019. At this time, some DRWG members renewed their interest in DR resources receiving utilization or energy payments. The IESO agreed to further consider this issue.[20]

80. In late February 2019, the IESO initiated a stakeholder engagement to inform IESO decision-making in the design and the implementation of the TCA. The first TCA engagement session was held on March 7, 2019 and included representation from generators, consumers, DR resources and other interested stakeholders. At this meeting, the IESO introduced its "Stakeholder Engagement Plan", which set out the following objectives:

(a) understand the changes involved in the development of the TCA;

(b) understand how proposed changes to the DRA may affect stakeholders; and

(c) gather stakeholder feedback on any significant issues and potential solutions associated with the proposed design features[21] (pp. 16-19).

81. Most participants in the stakeholder engagement were generally supportive of the decision to transition the DRA to the TCA, however, some DR representatives, including AMPCO, objected to launching the TCA without first resolving the issue of energy payments for DR resources. AMPCO and other DR representatives said DR participants would be at a competitive disadvantage vis-à-vis generators in the TCA if they were not entitled to energy payments.

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[19] Attached at **Tab "20"** is *Remarks by Peter Gregg at Ontario Energy Network Luncheon*, dated January 28, 2019, pp. 8-9.

[20] Attached at **Tab "21"** is *Demand Response Working Group Meeting Notes for February 12, 2019*, dated February 12, 2019, p. 11.

[21] Attached at **Tab "22"** is *Meeting Ontario's Capacity Needs*, "Evolving the DR Auction to Transitional Capacity Auction", dated March 7, 2019.

82. The IESO advised participants in the stakeholder engagement that the IESO intended to proceed with the TCA in December 2019, which would serve as an important learning experience for the IESO and market participants in preparation for the 2023 capacity gap, including allowing for price discoverability. The IESO, however, advised stakeholders that the issue of energy payments would be further considered as part of DRWG, including prioritizing the issue as part of the 2019 DRWG Work Plan, and that the IESO would follow up on the Navigant Paper and consider a "made-in-Ontario rationale supported by a good business case" [22]

83. In May 2019, The IESO posted the draft TCA design documents and draft market rule amendments, which were thereafter discussed by stakeholders at a stakeholder engagement session on May 22, 2019.

C. How else did the IESO respond to AMPCO and other DR representatives concerns?

84. In response to AMPCO's and other DR representatives' concerned about energy payments, the IESO decided to commence a separate stakeholder engagement initiative entitled *Energy Payments for Economic Activation of Demand Response Resources* (**"*Energy Payments Stakeholder Engagement*"**). The IESO commissioned a third-party consultant, Brattle Group, to support the research and analysis and sought stakeholder feedback on the inputs and outputs of third party research and analysis to inform the IESO's decision on the energy payment issue. This engagement and the Brattle study will follow up on some of the important matters identified for further consideration in the Navigant Paper.

85. On October 10, 2019, IESO issued the proposed reference question for consideration in the Energy Payments Stakeholder Engagement – "Should demand response resources receive energy payments when they are activated in-market?" (p. 17) – followed by the proposed scope for the engagement and associated Brattle third party study:

(a) What is the relevant Ontario context and history?

[22] Attached at **Tab "23"** is *Demand Response Working Group – Meeting Notes, dated April 25, 2019*, pp. 4, 11.

(b) What are the economic first principles that drive the activation decision for demand response resources?

(c) How are in-market activations compensated in other jurisdictions and what are the key takeaways for Ontario?

(d) If compensation is provided, what could the compensation model look like in Ontario?

(e) What are the benefits, risks, and implications of a) the status quo, and b) providing DR with energy payments in the near and longer terms?[23]

86. Stakeholders were invited to provide written feedback by October 25, 2019 on the proposed study scope which will inform the final study scope, which the IESO intends to publish in December 2019. AMPCO is participating in this engagement and provided input on the final study scope.

87. The IESO anticipates that the Brattle study will be completed by Q1 of 2020 and the IESO is targeting June 2020 for its rationale and final decision on energy payments for DR resources. The IESO will then commence the market rule amendment process for any changes that are needed to implement the decision.

88. The IESO does not have an estimated timeline as to when any necessary market rule amendments could be put in place to implement its final decision on the energy payments. The timeline would, among other things, depend on the findings of the study and the scope of implementation.

PART VIII - THE ADOPTION OF THE AMENDMENT

A. What was the recommendation of the Technical Panel on the Amendment?

89. On June 18, 2019, the proposed Amendments were submitted to the Technical Panel for review and comment. At the Technical Panel's meeting, on June 25, 2019, the Technical Panel voted to submit the proposed Amendments for stakeholder review and comment.

[23] Attached at **Tab "24"** is *Energy Payments for Economic Activations of DR Resources*, dated October 10, 2019, pp 23-24.

90. AMPCO, along with the Advanced Energy Management Alliance (“**AEMA”**) submitted a joint legal brief[24] that referenced FERC Order 745 and argued that the failure to compensate DR resources with energy payments in a manner equivalent to compensation provided to generation resources for similar services is unjust and unreasonable, unjustly discriminatory, and anti-competitive. The brief further argued that there exists “no rationale for implementing the TCA prior to the resolution of the issue of just and reasonable compensation for DR resources....”

91. Following further stakeholder review and feedback, the proposed Amendments were submitted to the Technical Panel on August 6, 2019. On August 13, 2019, the Technical Panel voted 11-1 to recommend the proposed Amendments for consideration to the IESO Board.[25] Three of the four consumer representatives on the Technical Panel voted in favour of recommending the Amendment.

92. The Technical Panel recommended the Amendments for approval by the IESO Board for reasons, which included the following:

(a) more competition in the TCA, which will put downward pressure on auction clearing prices and will benefit consumers;

(b) supports the development of a reliable capacity market to address future resource adequacy needs;

(c) implementing the TCA in phases, and making changes and accommodations in the future is a helpful step to gaining experience and developing an efficient and competitive electricity market;

(d) TCA helps to ensure that the power system is adequately prepared to meet future needs by providing additional mechanisms to address capacity and energy requirements;

(e) due consideration will be given to DR resource’s concerns about fair and reasonable compensation as part of the planned study;

[24] Attached as **Tab “25”** is AEMA/AMPCO Joint Brief, “IESO Proposed Capacity Auctions and Demand Response Resource”, dated July 2019.

[25] Attached as **Tab “26”** is the *Technical Panel Rationale*, dated August 13, 2019.

(f) providing energy payments to economic activations to DR resources is a wider market issue that will require more consultation has implications for the entire design of Ontario's electricity (energy and capacity) market; and it is It is not worth holding up TCA for this;

(g) the issue of energy payments for DR resources' is not-material because economic activations have historically been infrequent, and are projected to be infrequent in the future;

(h) TCA is a first step toward enabling competition to provide capacity;

(i) TCA is a prudent approach to maximizing future participation in advance of more significant capacity gap emerging; and

(j) TCA broadens participation while retaining features and functionality required for participation by HDR and dispatchable loads.

B. What were the IESO Board's reasons for adopting the Amendment?

93. As noted above, the Amendment was adopted by the IESO Board at its meeting of August 28, 2019.[26] The IESO Board provided reasons for its decision (the "**Reasons**").[27]

94. The Reasons state that the IESO Board reviewed the market rule amendment materials, including the positions of stakeholders and issues raised during the market rule amendment process, and decided to adopt the Amendment with an effective date of October 15, 2019.

95. The IESO Board identified the following reasons for adopting the Amendment:

(a) The Amendment is the first phase in evolving the DRA into a more competitive capacity acquisition mechanism that includes new resource types. This allows for increased competition in the acquisition of capacity for the benefit of Ontario customers.

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[26]Attached at **Tab "27"** is the Resolution of the IESO Board, dated August 28, 2019.

[27] Attached at **Tab "28"** are the Reasons of the IESO Board in Respect of an Amendment to the Market Rules, dated August 28, 2019 (the **"*Reasons*"**).

(b) The Amendment enables the IESO to begin implementing the TCA in a phased approach in order to be ready to address forecasted capacity needs in Ontario. The implementation of the first phase of the TCA will enable important experience and learnings with respect to integrating and administering new resource types in the Ontario capacity market sufficiently in advance of more significant capacity needs, currently projected to arise in the 2023 timeframe. A phased approach will reduce risk, while ensuring continued evolution of the market through the phased inclusion of new resources. This is a more prudent approach than attempting to implement a new capacity auction mechanism just prior to the time when there is a more significant capacity need.

(c) The Amendment enables non-committed dispatchable generators to participate in the TCA alongside dispatchable loads and hourly demand response resources. The Amendment provides an important opportunity for existing non-committed generators coming off contract to compete to provide reliability services, in this case capacity. In the absence of this opportunity to compete, these generators may choose to wind down their operations to the potential detriment of Ontario reliability and the interests of Ontario customers.

96. In its Reasons, the IESO Board specifically addressed the position of AMPCO that the Amendment unjustly discriminates against demand response resources. The Board noted that AMPCO's position "relies heavily" on FERC Order 745 which requires energy payments to demand response resources when they are dispatched subject to the condition that they meet a "net benefit requirement." The IESO Board observed that FERC Order 745 is not determinative because:

(a) while FERC Order 745 is a relevant consideration, it is not binding in Ontario;

(b) it is unclear whether the net benefit requirement applies in Ontario, given the differences in Ontario's market design;

(c) the IESO has committed to completing an independent study to determine whether there would be a net benefit to Ontario consumers if demand response resources receive energy payments for economic activations; and

(d) the energy payment issue is not material because economic activations in the DRA have historically occurred in very limited circumstances and are not expected to be a material consideration for the December 2019 auction.

97. The IESO Board concluded that implementing the Amendment was a prudent decision and that delaying the Amendment until the study is complete would be detrimental to the market overall, as it would "delay the introduction of increased competition, create an unnecessary delay in the phased approach to developing the auction in advance of substantial future capacity needs, and risk failing to retain access to existing generation assets coming off contract." [28]

98. The IESO Board also noted that the Technical Panel recommended the Amendment in a vote of 11-1 and that in respect of a process issue related to the AEMA/AMPCO joint brief, "exercised its discretion on an informed and reasonable basis."[29]

PART IX - RESPONSE TO AMPCO'S EVIDENCE

A. What is the IESO's response to Mr. Anderson's statements about the IESO proposing that participants in the DRA include "work around" payments in their bids?

99. The IESO does not know what Mr. Anderson is referring to in this statement. It is up to a DRA participants to determine their auction bid prices, including what costs they factor into their bid prices.

B. Why does the IESO say the impact of the Amendment on DR Resources is not material?

100. As noted above, DRA participants have historically been rarely activated in the energy market because their price bids have been far excess of the HOEP.

[28] *Reasons,* p. 4.
[29] *Ibid*, p. 5.

101. The IESO does not expect the likelihood of economic dispatch to materially increase in the commitment period under the December 2019 auction (May 1, 2020 to April 30, 2021). 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).[30] The total target capacity is negligible in the context of total system need.

102. As a result, the IESO does not anticipate any activations of HDR resources during the December 2019 commitment period (HDR resources have constituted the significant majority of participants in the DRA). The IESO also anticipates infrequent activations of dispatchable loads during the December 2019 commitment period.

103. Given this low probability of DR resource activation, the inclusion of a work around payment should have no material impact on DR auction offers for the December 2019 commitment period.

104. In the IESO's view, there is no justifiable rationale for DR resources participating in the TCA to include any work around payments in their bids. The amount of any work around should reflect both the costs of being activated and the very low likelihood of activation. The IESO has not been presented with any economic analysis to the contrary, and, in fact, AMPCO's answers to Board staff's interrogatories confirm the IESO's views (see AMCPO's interrogatory response to Board Staff's interrogatory No. 1).

C. Would energy payments increase the likelihood of activations of DR resources under the TCA?

105. The IESO does not expect any energy payments to be material in 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 states in section 3.1.5 of the Navigant Paper, "[l]arge commercial and industrial

[30] Attached as **Tab "29"** is *Demand Response Auction Pre-Auction Reports*, dated September 26, 2019.

customers with a high value of lost load are not likely to change their bids into the energy market because of utilization payments".[31]

D. Does the IESO have a view on the applicability of FERC "net benefit test" in Ontario?

106. No. This is a complex issue, which as noted by Navigant, has to consider the unique aspects of the Ontario market. The IESO has not yet made a final decision on the appropriateness and outcome of the net benefits test in Ontario, which is why the IESO is in the process of engaging with stakeholders and studying this issue as part of the Energy Payments Stakeholder Engagement.

107. That said, the only Ontario-specific analysis available is from Navigant who concluded that "more DR activations (as a result of bidding into the market at prices lower than traditional generators) would not actually lead to reduced cost to consumers since generators have their compensation guaranteed."[32] In other words, any reductions in the IESO market price may simply be offset by out of market Global Adjustment payments.

E. Will the IESO consider energy payments for DR resources?

108. Yes. While DR resources will not be entitled to receive energy payments if activated under the TCA during the December 2019 commitment period, the IESO has not made a final determination on the issue and will not do so until the conclusion of the Energy Payments Stakeholder Engagement. Following the conclusion of this engagement and issuance of the Brattle study, the IESO will make a final determination, including initiating any necessary market rule amendments to provide for energy payments to DR resources.

F. Why won't the IESO delay the TCA until it has resolved the issue of energy payments for DR resources?

109. In summary and as stated above:

[31] *Navigant Paper*, at 3.1.5

[32] *Navigant Paper*, at 3.2.

(a) It is the IESO's judgment as the province's reliability and planning authority that it is prudent to proceed now with the TCA in an incremental and phased manner and that there are real reliability and cost risks to delaying and not proceeding in this manner. These risks include losing the opportunities for the IESO and TCA participants to learn and adapt from a series of TCA auctions, as well as risking the loss of existing off contract generation facilities that may be important and cost-effective for the purpose of addressing the 2023 capacity gap in future capacity needs.

(b) AMPCO does not object to the TCA. It objects to commencing the TCA without changing the market rules to provide for energy payments to loads. This would be a major change to Ontario's electricity market design and it is the IESO's opinion that this sort of fundamental change should not be made without broad consultation and necessary study and analysis. FERC Order 745 is a relevant consideration but it is not binding in Ontario and, as the Navigant Paper makes clear, there are differences in Ontario's hybrid market and there are real doubts as to whether energy payments to DR resources would result in net benefits as conceived by FERC. This is why the IESO is undertaking the current stakeholder engagement on energy payments and third-party study, which the IESO is prioritizing and will result in an IESO final recommendation by the end of Q2 2020.

(c) AMPCO's members' interests are not determinative. The IESO, in accordance with its statutory mandate, must consider system reliability and the broader interests of other market participants and consumers. These considerations, as noted, weigh heavily in favour of proceeding with the TCA without delay. That being said, even if the IESO were to more narrowly focus on the interests of AMPCO members and other DR resources, there is no evidence that they will be materially harmed by proceeding with the TCA. The IESO has not seen any evidence from AMPCO that its members or other DR participants will be harmed. Moreover, AMPCO's assertions that DR participants will be competitively disadvantaged in the TCA auction is contradicted by the fact that DR resources have rarely been activated in the energy market and the IESO does not anticipate any material change in this respect over the December 2019 TCA commitment period.

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