**ONTARIO ENERGY BOARD**

**IN THE MATTER OF** the *Electricity Act, 1998*, S.O. 1998, c. 15, Sched. A, as amended;

**AND IN THE MATTER OF** an application by the Association of Major Power Consumers in Ontario requesting that the Ontario Energy Board review a set of Market Rule amendments made by the Independent Electricity System Operator (MR-00439-R00 to R05: Transitional Capacity Auction).

**EB-2019-0242**

# COMPENDIUM OF DOCUMENTS FOR CROSS-EXAMINATION OF COLIN ANDERSON AND LONDON ECONOMICS

**ASSOCIATION OF POWER PRODUCERS OF ONTARIO**

**NOVEMBER 22, 2019**

**INDEX**

1. Exhibit "B" to the Affidavit of Colin Anderson – Six (6) Submissions of AMPCO between March and July 2019 in respect of Market Rule Amendments Stakeholder Process

2. Exhibit "C" to the Affidavit of Colin Anderson – News and Updates Publication from the IESO, dated December 2019, titled "IESO Announces Results of Demand Response Auction"

3. Letter from Ian Mondrow to Christine E. Long dated October 31, 2019 – "Re: EB 2019-0242: Association of Major Power Consumers in Ontario (AMPCO) Application for Review of an Amendment to the Independent Electricity System Operator (IESO) Market Rules – Evidence Describing Experience with Demand Response in FERC Jurisdictional Markets"

4. Exhibit "L" to the Affidavit of David Short – "Hourly Demand Response (HDR) Testing Update"

5. AMPCO Responses to Interrogatories from OEB Staff, dated November 6, 2019

6. AMPCO Responses to Interrogatories from SEC, dated November 6, 2019

7. London Economics International LLC Responses to Interrogatories, dated November 20th, 2019

# TAB 1

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)

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## 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)

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## 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*<br>**Feedback Due:** June 5, 2019 | **Feedback provided by:**<br>Company Name: Association of Major Power Consumers in Ontario (AMPCO)<br>Contact Name: Colin Anderson<br>Phone: 416 260-0225<br>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:<br><br>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.

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 prior to resolution of the issue would:

(a) Undermine 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 not 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 equivalent 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) 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.

(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 regressive 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 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.
[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*

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[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 <u>must</u> 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 <u>have to be</u> 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.**

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

# TAB 2

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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.

< Back to IESO News

# TAB 3

October 31, 2019

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**VIA RESS AND COURIER**

Ms. Christine E. Long
Registrar and Board Secretary
**ONTARIO ENERGY BOARD**
P.O. Box 2319, 27th Floor
2300 Yonge Street
Toronto, Ontario
M4P 1E4

Dear Ms. Long:

**Re: EB-2019-0242: Association of Major Power Consumers in Ontario (AMPCO) Application for Review of an Amendment to the Independent Electricity System Operator (IESO) Market Rules.**

**Evidence Describing Experience with Demand Response in FERC Jurisdictional Markets.**

In P.O. No. 1 herein the Board directed AMPCO to file all affidavit material on which it intends to rely, whether in support of its motion for a stay of the Market Rule amendments or in support of its application. AMPCO did so on October 11th, as directed.

On October 18th the Board issued P.O. No. 2 in which it addressed, among other matters, interrogatories and evidence, and commented that;

1. it will allow an opportunity for intervenors and OEB staff to file evidence relevant to the issues to be considered in respect of the hearing of the Application; and

2. it is particularly interested in receiving evidence that describes the experience with compensation for demand response in markets in other relevant jurisdictions and the extent to which that experience is informative in the context of the IESO Market Rule amendments in issue in this proceeding having regard to any pertinent differences such as differences in market design or structure.

We have consulted with OEB staff and it appears that staff does not intend at this time to file any evidence. AMPCO agrees that evidence such as that which the Board has indicated it would be particularly interested in would be of assistance to all parties in considering the issues engaged by AMPCO's application.

Accordingly, and (given the tight schedule for this matter) pending and subject to the Board's determination of matters of cost eligibility, we write to advise that AMPCO wishes to file such evidence, in order to assist the Board and all concerned, and to seek confirmation that the filing of such evidence by AMPCO will be accepted.

AMPCO has retained Charles River Associates (CRAI) to prepare evidence on;

a. *The experience with compensation for economic activation of demand response in markets in FERC regulated jurisdictions; MISO, ISO-NE, PJM and NYISO.*

b. *The implications, if any, of seeking to apply such a compensation mechanism in a market like Ontario's.*

The lead author of the evidence and the witness presenting the evidence at the oral hearing and responding to questions will be David Hunger. Dr. Hunger is a Vice President at CRAI, and was formerly a senior economist at the U.S. Federal Energy Regulatory Commission (FERC) and was at FERC at the time that commission engaged in the inquiry that resulted in Order 745, as referred to in AMPCO's application material. Dr. Hunger will be assisted in his work on the evidence by Jordan Kwok, an Associate Principal at CRAI who has also worked at FERC and whose expertise includes ISO/RTO market policy the functioning of the FERC jurisdictional wholesale electricity markets to be reviewed in the evidence.

As this evidence;

i. is to be provided by independent experts;

ii. is to be responsive to the Board's stated interest in the kind of evidence which it would find of interest given the issues engaged by AMPCO's application;

iii. will be subject to interrogatories by all parties and cross-examination as appropriate; and

iv. is <u>not</u> affidavit material filed by AMPCO (as directed in P.O. No. 1 to have been filed by October 11$^{th}$),

we submit that it is not only entirely appropriate for AMPCO to file such evidence, but also that such filing would be of direct assistance to the Board and all concerned, and in the public interest in appropriate consideration, and resolution, of the instant application.

Given the November 8th deadline for filing additional evidence in this matter, CRAI has already commenced work on this evidence, and AMPCO has committed to paying for such work, and we would appreciate confirmation from the Board as soon as possible that it is prepared to accept the filing of the evidence as outlined above.

Yours truly,

Ian Mondrow

Ian A. Mondrow

cc: Glenn Zacher, Counsel for IESO
James Hunter, IESO
Colin Anderson, President, AMPCO
Michael Bell (OEB Staff)
Ljuba Djurdjevic (OEB Staff)
Intervenors of Record

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# TAB 4

# Hourly Demand Response (HDR) Testing Update

Demand Response Working Group

April 25, 2019

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# Purpose

- Background
- Performance
- HDR Testing Criteria
- HDR Test Activation Protocol – Update

# HDR Testing Background

- As per *Market Rules Chapter 7, 19.4.11* and *19.5.7*, IESO may direct HDR resources to perform activation up to a maximum of two test activations per commitment period
- Testing allows IESO to verify that a capacity obligation is deliverable by the HDR resource
- IESO test activations last for 4 hours per test and all HDR resources are tested in each commitment period
- HDR resources receive non-performance charges for failing a test activation primarily through two settlement charges (Capacity & Dispatch Charge)
- IESO may choose to not test a HDR resource twice within a commitment period based on its successful historical performance in test and in market activations

# HDR Testing Background

- HDR receive non-performance charges for failing a test activation primarily through two settlement charges:
  - **Capacity Charge (failure to provide capacity)**
    - Availability Payment for the month is clawed back
    - Capped at one charge per month
  - **Dispatch Charge (failure to follow dispatch)**
    - Availability Payment for the MW the DR resource failed to curtail multiplied by the hourly demand response auction clearing price
    - This charge is multiplied by a non-performance factor (1x, 1.5x, or 2x) depending on whether activation is during a peak period
- Test failure can be referred to IESO's Market Compliance and Assessment Division (MACD) as a potential market rule non-compliance
- As per *Market Rules Chapter 7, 19.4.8* and *19.5.4*, IESO may disqualify participation from future DR auctions when a resource consistently fails to provide performance as per the requirements

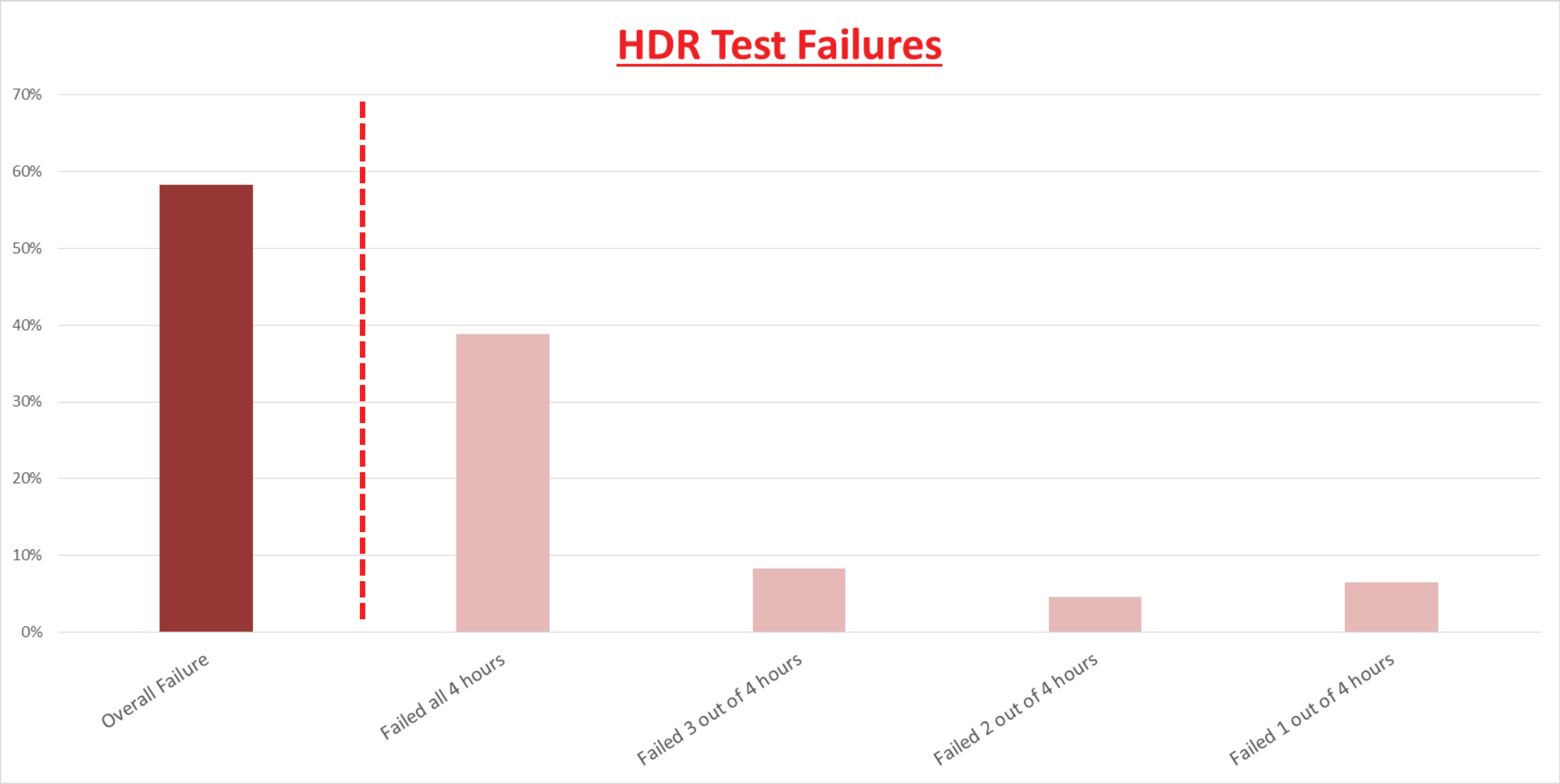
# HDR Testing Criteria

- HDR test performance is evaluated based on a resource's ability to:
  - Deliver capacity, measured as the average load reduction over a 4-hour test period, within a 20% deadband, and
  - Follow dispatch, measured as HDR resource's output against its dispatch signals in each interval, within a 15% deadband
- Testing in the ICA will require participants to demonstrate 100% of their capacity obligation
- HDR testing criteria will evolve in TCA as they review qualification and performance measures
- This could include a move to a measure of 100% of a facility's capacity obligation, without deadbands. This will be further explored in TCA Phase 2

# HDR Testing Performance

- IESO tests all Physical and Virtual HDR resources in each commitment period
- HDR can request to be tested at another time if they are unable to proceed with the test activation
  - Must file non-performance event; and
  - Bids should reflect inability to provide load reduction
- From Feb 2018 – Jan. 2019, only ~42% of HDR resources cleared testing
  - ~58% failure rate
  - ~39% failed in all hours (4 hour test)

# HDR Testing Performance




| | Overall Failure | Failed all 4 hours | Failed 3 out of 4 hours | Failed 2 out of 4 hours | Failed 1 out of 4 hours |
|---|---|---|---|---|---|
| Percentage | 58% | 39% | 8% | 5% | 6% |

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# HDR Test Activation Protocol

- As presented during the last DRWG, the IESO will be updating the testing protocol
  - Day ahead notification via phone call will be removed
  - Standby notification will be issued day ahead
  - IESO will also issue a Advisory Notice in advance of the standby notification (to confirm test activation)
- Changes will take effect at the start of the upcoming summer commitment period (May 1, 2019)

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# TAB 5

## 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. Cost per Curtailment:

    - 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. Number of Curtailments:

    - 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.

# TAB 6

## ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO)

### Response to SEC #1

**Reference:** Notice of Appeal, para. 24, 51.

**Preamble:**

AMPCO states that the Market Rules amendments at issue are "inimical" and "contrary" to many of the objectives of the [*Electricity Act*] including 1(f).

**Question:**

Please explain how AMPCO believes the Market Rules amendments at issue are inconsistent with the objective "to protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service".

---

**Response:**

AMPCO believes that more competition results in lower prices and higher levels of adequacy, reliability and quality of electricity service. AMPCO further believes that inviting generation resources which receive energy payments upon activation to compete against DR resources which do not will undermine competition for the provision of capacity resources, replacing one set of resources (DR resources) with another (generation resources).

AMPCO also believes that proceeding with a broadened capacity auction prior to addressing the availability of energy payments for DR resources is a step backwards in evolving towards a more competitive capacity auction process in particular, and a more competitive wholesale electricity market in general. Taking such a step creates unnecessary uncertainty and displacement of resources from their traditional market role, thus undermining confidence in the market and thus competition and better (i.e. lower) pricing in the longer term.

As stated by the IESO in evaluation of the success to date of its Demand Response Auction (DRA) program [as excerpted at AMPCO Application, page 5, paragraph 19, emphasis added];

> *As the electricity system moves toward competitive electricity auctions under IESO's Market Renewal project, the participation of consumers providing demand*

> *response will <u>increase competition leading to overall lower prices for Ontario Consumers</u>.*

Similarly, in its ruling on Order 745, FERC noted [as excerpted at AMPCO Application, page 10, paragraph 38, emphasis added];

> *In Order No. 719, the Commission found that allowing demand response to bid into organized wholesale energy markets <u>"expands the amount of resources available to the market, increases competition, helps reduce prices to consumers and enhances reliability</u>".*

The overall objective of the IESO's Market Renewal Program is to encourage and enhance competition [IESO Transitional Capacity Auction: Phase I Design Document, April 11 2019, page 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.*

In respect of capacity auctions in particular, the IESO has stated [IESO Incremental Capacity Auction High-Level Design: Executive Summary, March 2019, page 1]:

> *The [Incremental Capacity Auction] 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.*

The success of a capacity auction hinges on expanding participation in competition for the provision of capacity [IESO Incremental Capacity Auction High-Level Design: Executive Summary, March 2019, page 3]:

> *One of the advantages of the [Incremental Capacity Auction] 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.*

As related at paragraphs 25 and 26 of AMPCO's application, requiring DR resources to compete against generators without resolving the issue of fair and non-discriminatory compensation for DR resources for the value they provide to the energy market would undermine the current success of the Demand Response Auction and handicap DR resources from successfully competing within their own existing platform, because;

a. generators will bid into capacity auctions taking into account their anticipated energy payments; and

b. DR resources will have to complete against these bids without an equivalent energy payment stream, putting DR resources at a competitive disadvantage to generators in the expanded capacity market.

The IESO has recognized just such an issue in the context of compensating DR resources for "out of market" (i.e. test) activations. In a presentation provided on this issue to the Demand Response Working Group on June 19, 2019 [pages 36 *et seq.*], the IESO noted that *"[o]bserved bid prices and stakeholder feedback indicate that activation costs (explicit and opportunity) can be significant for HDR [hourly demand response] resources"*. The IESO further noted:

- When other resource types (dispatchable load, generator, import) are dispatched out-of-market they are eligible for some form of "make whole payment"
- *HDR resources do not receive a make-whole payment for out of market activiations*
- *These costs may be reflected in their capacity offers potentially increasing the cost of the capacity*
- *In the context of the proposed capacity auctions, where HDR will be competing against other resource types, how these costs are recovered will potentially impact market efficiency*

## ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO)

### Response to SEC #2

**Reference:** Notice of Appeal, para. 36-45.

**Preamble:**

AMPCO relies on FERC Order No. 745.

**Question:**

Please provide details regarding any material differences in the market structure of the Ontario versus that which FERC regulates, and how transferable the analysis contained in FERC Order No. 745 is to the Ontario market.

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**Response:**

Please see the response to Board Staff #2.

## 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.

**ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO)**

**Response to SEC #4**

**Reference:** Market Surveillance Panel, *Monitoring Report on the IESO-Administered Electricity Markets* Report (March 2019) https://www.oeb.ca/sites/default/files/msp-monitoring-report-20190429.pdf.

**Preamble:**

In the Market Surveillance Panel's March 2019 Monitoring Report on the IESO-Administered Electricity Markets report, it made a number of critical comments in the IESO's Demand Response Auction in which the Transitional Capacity Auction is replacing.

**Question:**

Please explain what impact, if any, AMPCO believes that providing energy payments to Demand Response providers have on the criticisms made by the Market Surveillance Panel.

---

**Response:**

The March 2019 MSP Monitoring report contained the following summary of recent changes to the Demand Response Auction:

> *The IESO has made some necessary changes to its Demand Response (DR) auctions. It has reduced the minimum number of hours that DR participants can be activated to one hour from four. It also introduced a price trigger, allowing the IESO to issue an activation notice to DR participants when pre-dispatch prices move higher than $200. Both of the changes are intended to increase the usage of Demand Response resources. Ratepayers will pay $161 million to resources procured under the first four Demand Response auctions. The Panel continues to question the value of this program for ratepayers, given that none of the hourly demand response resources have been activated to provide DR and reduce their consumption.*

AMPCO's Application regarding the Market Rule amendments does not relate to any of these changes, or to the overall value of a capacity auction to the Ontario market (though AMPCO continues to support such a capacity procurement mechanism, properly designed and implemented).

A net benefits test such as that required by FERC as a condition for energy payments to DR resources, properly designed and implemented for the Ontario market, would ensure that DR resources receive energy payments only when it is cost-effective from the market's perspective (i.e. the consumer's perspective) for that resource, inclusive of such energy payments, to be utilized. This means that the interests of consumers are best 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. Please see AMPCO's response to Board 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 7

# LEI responses to interrogatories

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

**November 20th, 2019**

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## Table of figures

# 1 Interrogatories to LEI from Kingston Cogen Limited Partnership

## 1.1 KCLP-1

**Interrogatory**

Reference: LEI Report, section 3.2.2, pp. 9-10

Preamble: FERC Order No. 745 at paragraph 49 describes "the billing unit effect of dispatching demand response resources" as:

> *"…when reductions in LMP from implementing demand response results in a reduction in the total amount consumers pay for resources that is greater than the money spent acquiring those demand response resources at LMP, such a payment is a cost effective purchase from the customers' standpoint."*

Footnote 119 of FERC Order No. 745 provides an example to illustrate:

> *"As a simple example, assume a market of 100 MW, with a current LMP of $50/MWh without demand response, and an LMP of $40/MWh if 5 MW of demand response were dispatched. Total payments to generators and load would be $4,000 with demand response compared to the previous $5,000. Even though, the reduced LMP is now being paid by less load, only 95 MW compared to 100 MW, the price paid by each remaining customer would decrease from $50/MWh to $42.11/MWh ($4,000/95). Therefore, the payment of LMP to demand resources is cost-effective."*

The LEI Report states that Figure 4 demonstrates the billing unit effect of DR under three separate conditions. Scenario 2 demonstrates the billing unit effect of DR and the circumstances when there is a zero net benefit from dispatching the DR Resources, i.e. the price point of the target of the net benefits test.

Questions:

(a) In Scenario 2, when there is no DR deployment, can you please confirm:
   i. When the LMP is determined, where total load to be supplied (Regular Load and DR load) is equal to 10,100 MWh, which is the total amount supplied?
   ii. When the offer price of Supplier V is $1,062/MWh, whether it is the marginal price-setting supplier, and hence the LMP is $1,062/MWh?
   iii. As per the simple example provided by the Commission, if the average price paid by each customer is $1,062/MWh, and total payments by load to generators would be equal to the LMP multiplied by total load supplied (i.e., $1,062/MWh x 10,100 MWh = $10,726,200).

(b) In Scenario 2, when there is DR deployment, can you please confirm:
   i. When the bid price of the DR resource is $1,000 MWh, the DR resource is the marginal price setting resource and hence the LMP is $1,000?
   ii. Whether the remaining load benefits pays generators the amount of $10,000,000, which is derived as the LMP times total load (i.e., $1,000/MWh x 10,000 MWh = $10,000,000)?

iii. Whether the amount the remaining load must pay to DR resources is $100,000, which is derived as $1,000 MWh x 100 MWh?
iv. As per the simple example provided by the Commission, total payments by the remaining load to generators and DR resources would by the sum of what they pay generators plus the amount that they pay the DR resource, which is equal to $10,000,000 + $100,000 = $10,100,000, and that the average price paid by the remaining load customer is $1,010/MWh?

(c) In Scenario 2, when there is DR deployment, can you please confirm:
i. Whether the bid price of the DR resource is $1,000 MWh, the DR resource is the marginal price setting resource and hence the LMP is $1,000?
ii. Whether the remaining load benefits from the lower LMP and pays generators the amount of $10,000,000?
iii. Whether the amount the remaining load must pay to DR resources is $100,000?
iv. As per the simple example provided by the Commission, total payments by the remaining load to generators and DR resources would by the sum of what they pay generators plus the amount that they pay the DR resource, which is equal to $10,100,100 and that the average price paid by the remaining load customer is $1,010/MWh?

(d) Do you agree that contrary to what Scenario 2 claims to demonstrate, this is not a zero net benefit scenario as contemplated by FERC Order 745 but instead a net benefit scenario?

(e) Do you agree that your calculation of the net benefits test and billing unit effect is different from the Commissioners definition?

**Response**

Figure 4 of LEI's report was meant to show hypothetical billing unit effects under an illustrative scenario where suppliers receive different prices applicable to their nodes, while load pays the load-weighted zonal average price. In LEI's Figure 4, Suppliers A-R, S, T, and U, are meant to exist at individual nodal points, while Supplier V and DR resource are at the same node. Under this illustrative scenario, suppliers are receiving their applicable nodal prices based on their supply, and load is paying the load-weighted average price.

Figure 4 should be interpreted with the above context in mind. As covered in the first question to LEI from KCLP (KCLP-1), when all suppliers receive the same price as 'Supplier V' or 'DR resource', dispatching the DR resource over Supplier V in LEI's Scenario 2 would be cost-effective.

## 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.

## 1.3 KCLP-3

**Interrogatory**

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

The Affidavit of Brian Rivard dated Nov 8, 2019 (the "Rivard Affidavit"), Paragraphs 53-57

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 53-57 of the Rivard Affidavit, Mr. Rivard provides a summary of the FERC Order 745 and the net benefits test.

Questions:

(a) Please identify any points on which LEI is in agreement with, or disagrees with, Mr. Rivard's overview of FERC Order 745 and the net benefits test. If LEI generally agrees with Mr. Rivard, please confirm this.
(b) If LEI disagrees with any aspect of Mr. Rivard's overview, please explain the basis of this disagreement.

**Response:**

LEI broadly agrees with Dr. Rivard's brief description of FERC Order 745 provided in Paragraph 53, and agrees that the contents in Paragraph 54 and 55 are consistent with LEI's understanding. LEI does not disagree with the information contained in Paragraph 56, but believes it would be more appropriate to refer to "remaining load" rather than "non-DR consumers." For the contents in Paragraph 57 related to FERC Order 745, LEI would characterize the net benefits test as seeking to avoid situations where dispatching DR may result in higher costs per unit for remaining load, rather than to "maximize the benefits to non-DR participants."

## 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.

## 1.5 KCLP-5

**Interrogatory**

Reference: LEI Report, Section 4, pages 15-32, Rivard Affidavit, Paragraphs 79-85

Preamble: At section 4 (pages 15-32) of the LEI Report, LEI provides an overview of how DR resources are compensated in PJM, ISO-NE and NYSIO.

At paragraphs 79-85 of the Rivard Affidavit, Mr. Rivard provides a summary of the results of a non-exhaustive scan of the academic literature and reports prepared by the RTOs, ISOs and the market monitors for empirical evidence on the effects and implications of the implementation of FERC Order No. 745.

Questions:

(a) Does LEI agree that Mr. Rivard's summary contained at paragraphs 79-85 of the Rivard Affidavit is complimentary to the research and analysis completed at pages 15-32 of the LEI Report?

(b) Please identify any points on which LEI is in agreement with, or disagrees with, Mr. Rivard's summary of the results of his non-exhaustive scan of academic literature and reports. If LEI generally agrees with Mr. Rivard's summary, please confirm this.

(c) If LEI disagrees with any aspect of Mr. Rivard's summary, please explain the basis of this disagreement.

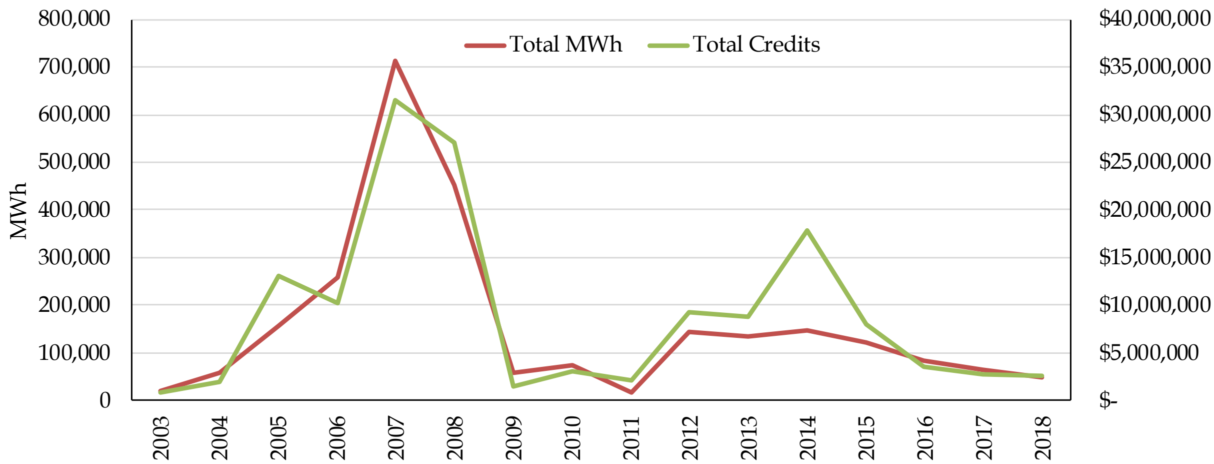
**Response**

Although LEI sees very little overlap between Section 4 of its report and Paragraphs 79-85 of Dr. Rivard's Affidavit, they can be viewed as complementary. Section 4 of LEI's report was intended to provide an overview of DR participating in programs administered by a selection of US ISOs/RTOs (including those programs to which FERC Order 745 does not apply) and provide some cross-cutting observations, relying primarily on information from the ISOs/RTOs themselves. Paragraphs 79-85 of Dr. Rivard's Affidavit provides a non-exhaustive scan of research on the effects FERC Order 745 has had on wholesale markets, and is focused largely on academic studies. LEI's disagreement is not with regards to Dr. Rivard's summary but rather with regards to the relevance of the articles to Ontario.

Paragraph 80 of Dr. Rivard's Affidavit and Section 4 of LEI's report both reference PJM State of the Market Reports for information on payments made to and dispatch of DR resources. As noted in Paragraph 80 of Dr. Rivard's Affidavit, monthly data from 2010 to 2019 shows an increase in economic demand response reductions and credits in PJM after FERC Order 745 was implemented (April 2012, as compared to the months before FERC Order 745 was implemented).

As discussed in Section 4 of LEI's report, considering the size of the PJM market, these credits and reductions are a very small proportion of total DR revenues and PJM's total load. In addition to information contained in Section 4, LEI notes that extending the historic period further back would show that total credits and DR reductions were noticeably higher in 2007 and 2008 as compared to the period from 2012 onwards, which can be seen in Figure 1.

**Figure 1. Annual economic program credits and MWh (2002-2018)**




Sources: data from 2002 to 2009 relies on Table 6-4 from the 2013 *State of the Market Report for PJM: Section 6 – Demand Response;* data from 2010 to 2018 relies on Table 6-4 from the 2018 *State of the Market Report for PJM: Section 6 – Demand Response.*

## 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.

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.

## 1.7 KCLP-7

**Interrogatory**

Reference: LEI Report

Rivard Affidavit

Preamble: The preceding questions asked very specific questions to explore the similarities and differences between the LEI Report and the Rivard Affidavit.

Questions:

(a) Are there any other areas of similarities or differences as between the LEI Report and the Rivard Affidavit that you would like to identify for the OEB?

**Response**

The two reports differ in the scope provided to their authors.

The LEI report was focused on describing FERC Order 745, conditions in US wholesale and retail markets, and contextual similarities and differences between Ontario and the US. LEI was not asked to develop conclusions with regards to how a net benefits test could be properly designed for Ontario, or whether any particular party would be harmed through any specific configuration of an IESO market rule.

By contrast, Dr. Rivard was asked to offer his "independent views on the economic merit of AMPCO's position in this proceeding".

# 2 Interrogatories to LEI from the School Energy Coalition

## 2.1 SEC-OEBStaff-1

**Interrogatory**

[KingstonCoGen, Evidence of Brian Rivard, para. 53-85] Please provide LEI's views on Mr. Rivard's evidence regarding the application of FERC Order No. 745 to Ontario.

**Response**

Please see LEI's responses to the KCLP interrogatories, and the following interrogatories specifically: KCLP-2 (d), KCLP-4, KCLP-5, and KCLP-6.