ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO)

Response to Staff #1

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

Preamble:

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

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

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

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

Questions:

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

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

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

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

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

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

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

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

Response:

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

The cost elements associated with curtailment are specific to each individual participant based on a number of business and operational factors and no two participants are likely to have the same characteristics, inputs or outcomes. Accordingly, AMPCO is not in a position to provide an approximate percentage value that each element would account for in the total auction price and that would be reflective of the cost elements of a class of resources.

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

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

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

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

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

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

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

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

- Natural Gas/power price forecast

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

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

- Availability Risk
  - Possibility of penalties

- Administration costs
  - Contract management
  - Metering
  - Daily Bidding

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

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

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

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

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

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

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

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

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

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

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

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.