EB-2019-0242

Association of Major Power Consumers of Ontario (“AMPCO”)

Kingston CoGen Limited Partnership (“KCLP”)

Cross-Examination Compendium

Panel 1 – AMPCO

November 25, 2019

Index

TAB A

current and future energy needs reliably, transparently, efficiently and at lowest cost."[1] The Ontario Energy Board (OEB) is seeking to modernize the design of distribution and regulated retail rates in the face of an evolving sector, to promote the efficient and equitable recovery of system costs that are largely fixed and sunk, and to facilitate the rational adoption of new technologies.[2] More recently, the Ontario government held consultations with Ontario businesses to hear first-hand about industrial electricity pricing and programs, and their ideas on how the province's electricity system can make business more competitive.[3]

From a technological perspective, the integrated system as a whole could soon face serious competition from new distributed energy solutions, leading to the gradual decline in the use of the province's grid-related assets. Global technological development is enabling greater choice for consumers on how they use traditional electric grid services. Distributed generation solutions are becoming more cost-competitive with grid-sourced electricity, opening up the possibility that many consumers will turn to these solutions in the future as a way to lower their electricity costs.[4]

The pace of adoption of new distributed technologies will depend on the prices and regulated rates for traditional grid services. Ineffective pricing of grid services could delay consumer investment in these new innovative options when they are efficient and make sense from an environmental standpoint. Alternatively, ineffective pricing of grid services could inefficiently hasten investment in these solutions, causing the premature stranding of grid assets and higher costs for Ontario electricity consumers overall. For this reason, a renewed focus on efficient pricing and rate design of traditional grid services is timely.

One component of the overall electricity cost that deserves particular policy attention is the global adjustment. The global adjustment is a monthly fee paid by Ontario consumers to cover the fixed cost to build and maintain generation assets in the province, and to fund Ontario's conservation programs. The global adjustment is currently the largest component of the average consumer's total electricity bill. It represents roughly 80 percent of the province's generation supply costs and 45 to 60 percent of the cost to provide the fully bundled grid-related service.

Several commentators have raised concern over policy decisions that affected the size and nature of the costs incurred under the global adjustment, and the manner in which these costs are allocated across consumers.[5] Unfortunately, the costs in the global adjustment are essentially sunk and cannot be avoided; there is very little that can be done to redress the decisions that affected the size and nature of the costs. However, there are opportunities to redress decisions on how the costs are allocated to consumers. The current approach, the Industrial Conservation Initiative (ICI), provides an extreme price incentive for large consumers to reduce their demand during system peak demand hours. In some cases, it has induced large consumers to invest in distributed energy solutions such as storage or behind-the-meter generation to avoid paying the global adjustment. However, because the cost in the global adjustment are largely fixed, this results in a shifting of costs to other consumers, which creates an incentive for these consumers to also turn to distributed energy solutions to reduce their costs. Over time, this cycle risks the eventual stranding of the province's large grid-related assets. It would also imply higher costs for Ontario consumers on the whole.

This Policy Brief brings an economic perspective to the ongoing policy discussions around the global adjustment, beginning in the next section with background on the global adjustment and the ICI, followed by an evaluation of how the generation costs in the global adjustment are priced and allocated.

The Policy Brief then offers suggestions on how to improve generation cost pricing in the province to promote more efficient and equitable outcomes. In particular, it offers a practical approach for decomposing the global adjustment into three separate components: capacity costs, an energy price hedge, and system-wide fixed costs, and argues that from an efficiency and equity standpoint, a different cost recovery method should be used for each component. This proposed approach, which is compatible with the general direction of the current pricing policy initiatives, would reduce the risk of hastening investment in distributed solutions, the stranding of existing grid assets and higher overall costs for Ontario's electricity consumers.

BACKGROUND ON THE GLOBAL ADJUSMENT AND INDUSTRIAL CONSERVATION INITIATIVE

Global Adjustment

The global adjustment was established in 2005 as part of a policy transition from a fully competitive market structure to a hybrid market structure that:

- complemented the competitive wholesale market with long-term centralized planning and procurement;
- regulated the prices for certain generation assets;
- introduced a Regulated Pricing Plan (RPP) for low volume residential and small business consumers; and
- created a greater role for government through Ministerial Directive powers.[6]

Ontario Regulation 429/04, instituted the global adjustment as the variance account used to:

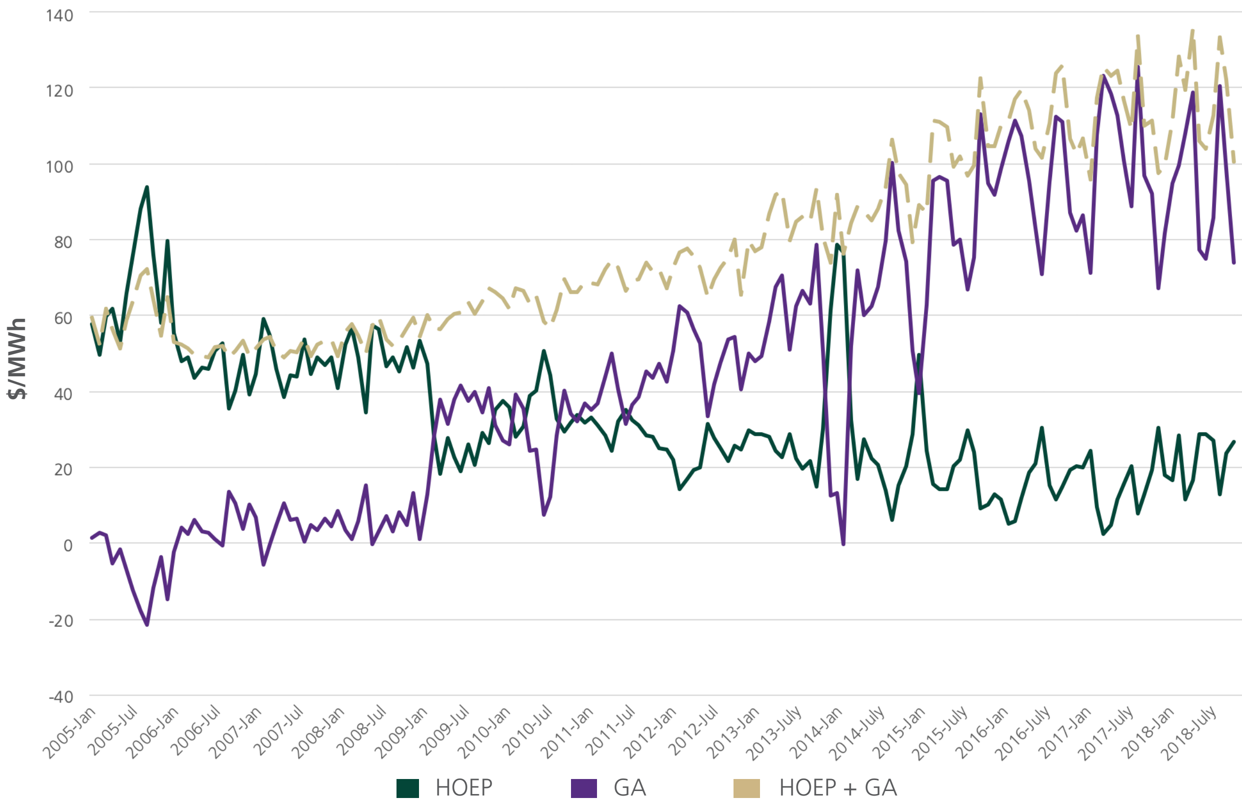
- reconcile differences between payments made to generators at the competitive wholesale market price and payments made through regulation or contract that differ from the wholesale market price; and
- fund the province's conservation and demand management programs.

The new regulation provided the global adjustment be recovered from Ontario consumers based on an individual consumer's share of the total net volume of electricity withdrawn from the grid each month (i.e., a volumetric rate).[7]

Initially, the regulated component of the global adjustment reflected electricity generated by Ontario Power Generation's (OPG) baseload hydroelectric and nuclear assets[8] (also known as "heritage assets"), and the contract component reflected electricity generated by the existing non-utility generator assets under contract to the Ontario Electricity Finance Corporation. OPG's heritage assets received an average regulated rate of 4.5 cents per kilowatt-hour, which was low relative to the prevailing competitive market price. The government expected that regulating the price of OPG's assets would "reduce price volatility and have a stabilizing effect on electricity prices, which will be of great benefit to Ontario's power consumers."[9]

In the first year, the global adjustment typically represented a monthly credit to consumers as market prices were well above the average rate paid to OPG's heritage assets. However, the government gradually directed the OPA (now the IESO)[10] to sign new contracts with generators, initially to ensure a reliable level of generation capacity, and eventually to promote broader government policy objects such as the environmental and health benefits related to the reduction of greenhouse gases, and the economic benefits related to the development of green industries and green jobs.[11] The price or revenue assurances provided under these contracts were generally higher than the competitive market price. As the contract component grew, the global adjustment grew to become a monthly charge to consumers. Figure 1 depicts the growth of the global adjustment relative to the competitive market price, the average monthly Hourly Ontario Energy Price (HOEP), from 2005 to 2018.[12]

Figure 1 | Hourly Ontario Energy Price and Global Adjustment, 2005 to 2018



Source: Author created from data available from the IESO.

Industrial Conservation Initiative

In June 2011, the government introduced amendments to Ontario Regulation 429/04 through the Industrial Conservation Initiative (ICI). The amendments changed the way the global adjustment was allocated to Ontario consumers.[13] The ICI created two classes of consumers for the purpose of allocating the global adjustment. Class A consumers, which were consumers with an average monthly peak demand greater than five megawatts (MW), were charged the global adjustment based on their share of consumption during the five highest demand hours (coincident peak demands) in Ontario during a defined base period from May 1 to April 30 of the previous year. Class B consumers, which included all remaining consumers, continued to be charged the global adjustment volumetrically, but based on the total Class B share of consumption during the five coincident peak demand hours.

The ICI was introduced to address the concerns raised by large volume consumers who believed that they were paying more than their fair share of the fixed costs incurred to maintain and build sufficient generation to meet peak demands. The ICI offered large industrial consumers an incentive to reduce their consumption during critical peak demand hours, which was expected to reduce the need to procure new peaking generation capacity.[14]

The ICI has been amended since 2011 to expanded Class A eligibility. Class A consumers now include consumers with an average monthly peak demand greater than 1 MW, and consumers in certain manufacturing and industrial sectors, including greenhouses with an average monthly demand greater than 500 kilowatts (kW) during the annual base period.

ISSUES WITH THE GLOBAL ADJUSTMENT AND GENERATION COST PRICING

Several commentators have criticised government decisions that affected the size and nature of the costs in the global adjustment. For example, the Office of the Ontario Auditor General (2015) identified several problems with past generation and conservation procurement decisions, including the procurement of more capacity than needed to meet Ontario's peak demands, overpayment for renewable energy, costly gas plant cancellations, ineffective conservation programs, and cost-ineffective conversion of the Thunder Bay coal plant to biomass. The Auditor argues that these decisions resulted in inefficient and unnecessary expenditures that inflated the size of the global adjustment.

Trebilcock (2017) argues that policies such as the Green Energy and Green Economy Act, which were implemented to reduce carbon emissions from the electricity sector and to stimulate job creation in the green energy economy failed to deliver on their objectives in a cost-effective manner. While the policies yielded modest environmental benefits, it had a likely negative effect on employment and dramatically increased the size of the global adjustment and users' electricity costs.

Unfortunately, little can be done to redress the policy decisions that affected the size and nature of the costs incurred within the global adjustment, as these costs are essentially sunk (see Insert 1 for a glossary of economic terms). The IESO is under contractual commitment to pay generators for these costs. To avoid or reduce these costs, the IESO would have to renegotiate the contracts it has with generators. While it is unlikely that generators would accept changes that would make them worse off, there may be an opportunity to push some costs further into the future. Similarly, the OEB has established regulated rate commitments with OPG. The OEB could reduce the size of payments to OPG in future rate hearings by refusing the recovery of some costs or forbearing on regulation all together. Figure 2 depicts the share of global adjustment paid to different generation technologies and their share of total installed capacity for 2017.

Insert 1 | Glossary of Economic Terms

Variable costs: Costs that vary with the quantity of output produced.

Fixed costs: Costs that do not vary with the quantity of output produced.

Short-term: A period of time in which the optimal decisions of consumers and producers are constrained by the existing stock of assets, (i.e. consumers' energy drawing assets or devices and total generation capacity are fixed).

Sunk cost: A cost already incurred or committed to being paid that cannot be avoided or recovered.

Marginal cost: The additional cost incurred by a firm to increase production by one more unit of output.

TAB B

Executive Summary

In 2011, the Government of Ontario introduced a policy known as the Industrial Conservation Initiative (ICI), which changed the way in which Global Adjustment costs are allocated to different classes of consumers.

The stated purpose of the ICI is to provide large consumers with an incentive to reduce consumption at critical peak demand times. The resulting reductions in peak demand were expected to reduce the need to invest in new peaking generation and imports of electricity from coal-reliant jurisdictions. The ICI was also intended to increase the efficiency of price signals, while also recognizing concerns that large volume consumers were paying more than their fair share of costs.

The costs recovered through the Global Adjustment include the costs of contracted and regulated generation, as well as the cost of some conservation programs. The Global Adjustment has grown from $700 million in 2006 (8% of total electricity supply costs) to $11.9 billion in 2017 (more than 80% of total electricity supply costs). As the Global Adjustment has grown, so too has the reduction in peak demand by consumers participating in the ICI. The Panel estimates that ICI participants reduced their consumption by 42% during peak demand conditions in 2016, compared to reductions of 33% and 26% in 2013 and 2011 respectively.

The ICI has the effect of shifting the electricity costs recovered through the Global Adjustment from larger volume consumers to households and small businesses. Because the Global Adjustment now accounts for the lion's share of electricity supply costs, baseload as well as peaking, how those costs are allocated between large and small consumers has a significant effect on the effective electricity prices that they pay. Since its introduction in 2011, the ICI has shifted nearly $5 billion in electricity costs from larger consumers to smaller ones. In 2017, the ICI shifted $1.2 billion in electricity costs to households and small businesses—nearly four times greater than the amount in 2011. In 2017, the ICI increased the cost of electricity for households and small businesses by 10%.

The Market Surveillance Panel (Panel), in the course of its monitoring of activities related to the IESO-administered market that may affect the efficient and fair operation of that market, regularly reports on effective electricity prices, including the Global Adjustment component of those prices. The Panel has noted on more than one occasion that the ICI affects the effective price paid by different classes of consumers.

In the Panel's view, the ICI as presently structured is a complicated and non-transparent means of recovering costs, with limited efficiency benefits. The magnitude of the incentive to reduce peak demand during a year is inversely related to the Province's need for peak demand reduction the following year. Arguably, the ICI does not allocate costs fairly in the sense of assigning costs to those who cause them and/or benefit from them being incurred.

The Panel recognizes that striking an appropriate balance between potentially competing objectives and interests in cost allocation is a challenge and will remain so. The Panel has prepared this report to contribute in a positive way to any future discussions regarding that balancing exercise, and with a view to promoting consideration of market efficiency and fairness.

The Panel notes by way of postscript that, as it was finalizing this report, the Ontario government announced in its 2018 Ontario Economic Outlook and Fiscal Review that it was launching a public review of electricity pricing for industrial consumers as part of the government's open for business policy.

1. Introduction

The Global Adjustment is the mechanism by which certain electricity supply costs are recovered from electricity ratepayers. Since its introduction in 2005, the Global Adjustment has steadily increased as a percentage of total electricity supply costs, accounting for over 80% ($11.9 billion) in 2017. Given its magnitude, the allocation of Global Adjustment costs amongst consumers has a significant impact on the price consumers pay for electricity.

In January 2011, a new methodology for allocating Global Adjustment costs, called the Industrial Conservation Initiative (ICI), came into effect. Since its introduction, participation in the ICI has shifted nearly $5 billion in Global Adjustment costs from larger consumers to residential consumers and small businesses. In 2017, $1.2 billion in electricity costs were shifted, increasing the cost of electricity for residential consumers and small businesses by 10%.

The Panel recognizes that finding the right balance between competing objectives and interests when allocating costs is challenging. The Panel suggests that the following principal criteria are useful when evaluating methodologies—like the ICI—for allocating fixed costs: efficiency; fairness; simplicity/transparency; and cost recovery. In this report, the Panel assesses the performance of the ICI against those criteria.

2. Background: The Global Adjustment

Generating electricity requires significant investment in infrastructure. The bulk of these investments occur when building and maintaining electricity generators. In the electricity sector, the costs of building and maintaining a generator are referred to as "capacity" costs, which include a reasonable rate of return on those investments. As electricity is consumed on a day-to-day basis, capacity costs are considered "fixed" in that they do not increase or decrease with increasing or decreasing production. The fixed capacity costs associated with generating electricity ultimately need to be recovered from the consumers who benefit from this infrastructure.

In addition to fixed capacity costs, there are incremental (variable or "marginal") costs associated with generating electricity. Marginal costs are those associated with generating the electricity itself, such as the purchase of natural gas fuel, and increase or decrease with increasing or decreasing production. These costs also need to be recovered from consumers. In Ontario, there is a wholesale electricity market where generators sell electricity at the prevailing market price, which is intended to cover, at a minimum, the marginal costs of generating that electricity. In cases when the market price exceeds the marginal cost of generating the electricity, the excess revenues from the wholesale electricity market help the investor recover the fixed capacity costs associated with building and maintaining its generator.

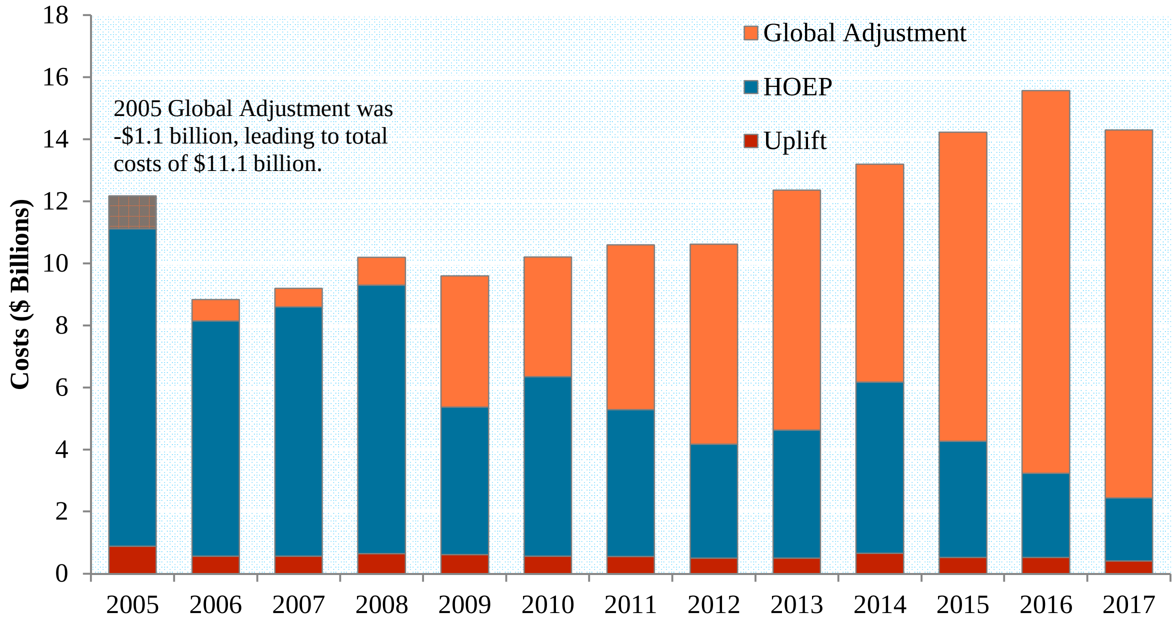
For a number of reasons, revenues from Ontario’s wholesale electricity market have been insufficient to cover many generators’ fixed capacity costs. In electricity sector parlance, this is referred to as the “missing money” problem. Without long-term financial viability, capacity needed to meet demand may be retired, or may not be built in the first place. Such were the circumstances in the mid-2000s when demand for electricity was growing and Ontario was facing increasingly tight supply conditions.

To address the “missing money” problem and incent investment in new generating capacity, Ontario offered long-term contracts to potential project proponents. While the terms of the contracts differed by generating technology and time of procurement, all contracts were intended to guarantee that investors would recover the fixed capacity costs associated with building and maintaining new generation capacity. This approach proved very successful and significant new generating capacity was built from 2006 onwards. In addition, some of the generation assets owned by Ontario Power Generation Inc. are subject to regulated rates that cover their fixed capacity costs. Generally speaking, when market revenues are insufficient to cover the contracted or regulated amount, supplementary payments need to be made, so a new mechanism was needed to recover these payments from electricity consumers. The Global Adjustment, a charge to Ontario electricity consumers, serves that purpose.

Since its introduction in 2005, the Global Adjustment has made up an increasing portion of the cost of electricity supply charged to consumers. There are many factors driving this trend, including an increasing number of dollars committed to an increasing number of contracted generators. Also a factor is a steady decrease in wholesale electricity market prices, which decreases revenues from the market and necessitates the recovery of a greater portion of fixed capacity costs through the Global Adjustment.

Figure 1 displays how the recovery of electricity supply costs has increasingly shifted from wholesale electricity market charges (the Hourly Ontario Energy Price or "HOEP" and uplift),[1] to the Global Adjustment, which grew from $700 million in 2006 to $11.9 billion in 2017.

Figure 1: Annual Electricity Supply Costs
2005 – 2017
($ Billions)



3. Background: The Industrial Conservation Initiative

Prior to 2011, the Global Adjustment was allocated to all Ontario consumers on a volumetric basis: the costs associated with the Global Adjustment were summed and allocated equally over all megawatt-hours consumed in the Province each month.[2] For example, if the total Global Adjustment was $500 million for a given month, and Ontario consumption was 10 million megawatt-hours, there would be a $50/MWh Global Adjustment charge for all consumers.

In 2011, the Government of Ontario introduced the ICI, a new way of allocating Global Adjustment costs. The change in the allocation of the Global Adjustment was intended to provide large consumers with an incentive to reduce consumption at critical peak demand times. The resulting reductions in peak demand were expected to reduce the need to invest in new

[1] Uplift is charged by the IESO to wholesale market participants in order to recover the costs associated with various wholesale electricity market services and programs, such as the Generation Cost Guarantee program.
[2] Exporters do not pay the Global Adjustment.

peaking generation and imports of electricity from coal-reliant jurisdictions. The ICI was also intended to increase the efficiency of price signals, while also recognizing concerns that large volume consumers were paying more than their fair share of costs.[3]

The Industrial Conservation Initiative: How it Works

The ICI is the mechanism for allocating Global Adjustment costs amongst Ontario consumers. Under the ICI, a consumer's allocation of Global Adjustment costs depends on their consumer class and consumption profile.

New Consumer Classes

The introduction of the ICI divided Ontario consumers into two classes: "Class A" and "Class B". Initially, ***Class A*** was limited to very large consumers with an average monthly peak demand of more than 5 MW (primarily large industrial consumers). Since then, the government has expanded eligibility such that Class A now includes all consumers with an average monthly peak demand of more than 1 MW, as well as consumers in certain manufacturing, industrial and agricultural sectors with an average monthly peak demand of more than 0.5 MW. As a result, the number of Class A consumers has increased from less than 200 in 2011 to over 1,600 in 2018. ***Class B*** comprises all other consumers, including residential consumers and small businesses.

Allocating Global Adjustment Costs

Under the ICI, Class A and Class B consumers are allocated Global Adjustment costs differently. ***Class A*** consumers are charged the Global Adjustment based on their share of consumption during the five peak demand hours in a year.[4] For example, if a Class A consumer was responsible for 1% of Ontario demand during the five peak demand hours in a 12-month period, they would pay 1% of the Global Adjustment in the ensuing 12-month period.[5] By reducing their consumption during peak demand hours, Class A consumers are able to reduce the amount of the

[3] The proposal to amend O. Reg. 429/04 is available at: http://www.ebr.gov.on.ca/ERS-WEB-External/displaynoticecontent.do?noticeId=MTEwNzI0&statusId=MTY2MTgw&language=en
[4] Referred to as "coincident peak" demand hours, these five peak demand hours must occur on different days. For example, in 2016 three of the five highest demand hours occurred on August 8th, but only the peak hour during that day (hour ending 18 at 23,100 MW of demand) was treated as one of the five peak demand hours for the purposes of allocating the Global Adjustment under the ICI.
[5] The year-long period during which a consumer's demand during peak demand hours is recorded is the "base period", taking place from May 1 to the following April 30. A consumer's peak demand factor (i.e. percentage of total peak demand) during this base period determines their share of the Global Adjustment for a 12-month "adjustment period" beginning July 1 following the end of the base period.

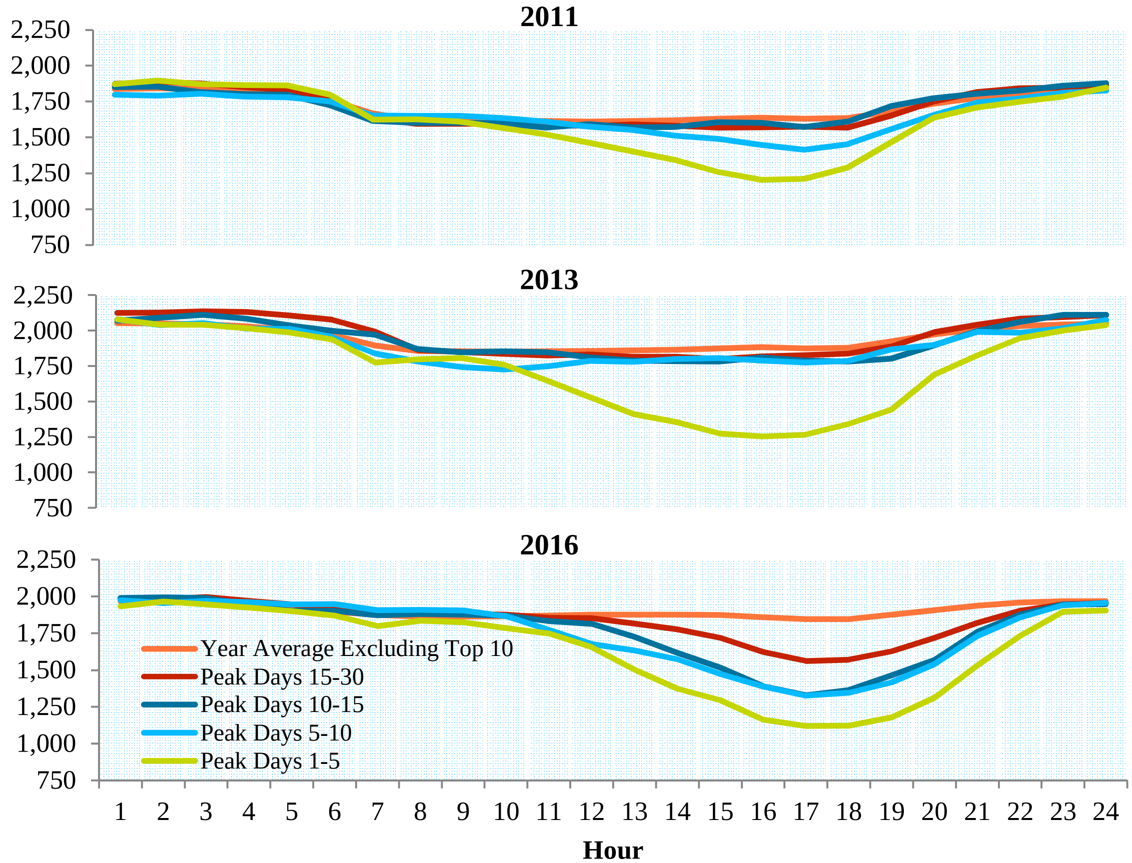
Global Adjustment they pay. Those avoided costs are shifted to ***Class B*** consumers, who pay the remaining Global Adjustment costs on a volumetric basis.

3.1 Impact on Class A Consumption during Peak Demand Hours

The ICI provides Class A consumers with a strong incentive to reduce consumption during peak demand hours. The Panel estimates that by reducing consumption by one megawatt during each of the five peak demand hours in 2016, a Class A consumer would have saved approximately $520,000 in Global Adjustment charges. This incentive has proved effective in reducing Class A consumption during peak demand hours. Figure 2 compares the aggregated consumption profile of all directly-connected Class A consumers[6] on days when peak demand hours occurred in 2011, 2013, and 2016. Reductions in consumption can be measured by comparing consumption during days with a peak demand hour ("Peak Days 1-5" line) to consumption during days without a peak demand hour ("Year Average Excluding Top 10" line).

[6] Directly-connected Class A consumers are those that are connected to the transmission grid. This does not include Class A consumers that are connected at the distribution level. Except where otherwise noted, references to Class A consumers in this report refer to all Class A consumers.

Figure 2: Directly-Connected Class A Response During Peak Demand Days 2011, 2013 and 2016 (MW)



Over the years, consumption reductions have grown as the magnitude of the Global Adjustment, and thus the ICI incentive, have grown. In 2016, on the five days when a peak demand hour occurred, the ICI produced a maximum hourly reduction in directly-connected Class A consumption of 42%, and more moderate reductions during other hours of those days. This compares to a 33% reduction in 2013, and a 26% reduction in 2011.

The Panel cannot precisely determine the total magnitude of peak demand reductions resulting from the ICI as it does not have access to hourly consumption data for Class A consumers that are connected at the distribution level, and not directly connected to the transmission grid.[7] In 2016, 40% of Class A consumers were connected at the distribution level, increasing to 49% in 2017. Based on the assumption that these distribution-connected Class A consumers had the

[7] For more information on data limitations, see the Panel's April 2015 Monitoring Report, pages 105-109, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2013-Apr2014_20150420.pdf

same consumption profile as directly-connected Class A consumers, the Panel estimates that the ICI produced an average peak reduction of 1,200 MW on the five days with peak demand hours in 2016.

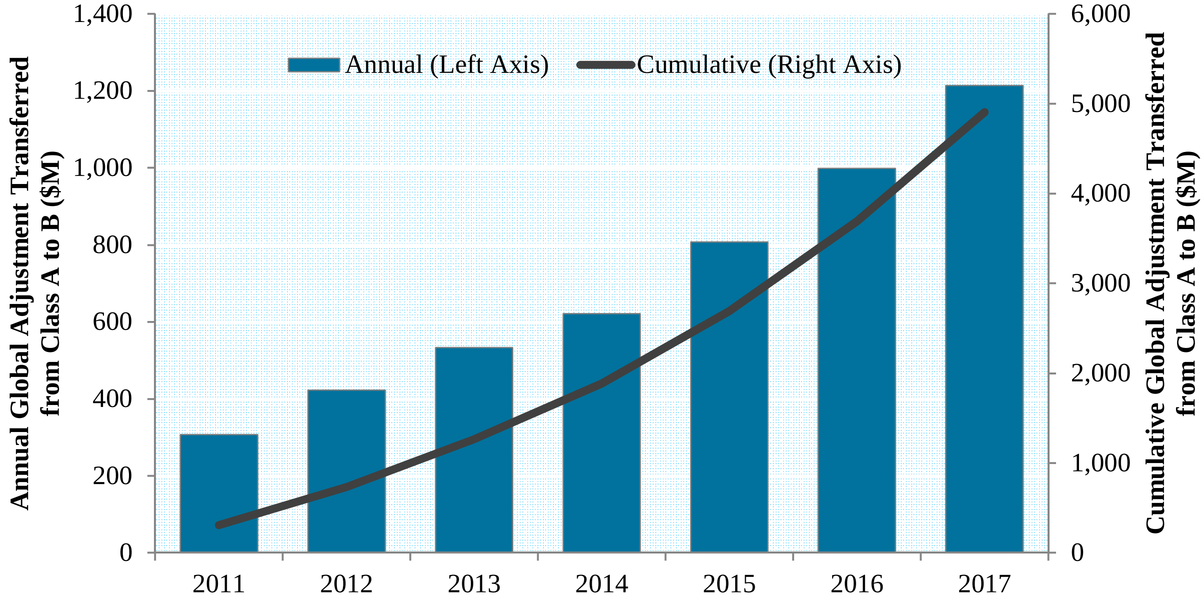
Due to the uncertainty around the days when the year's top five peak demand hours will occur, and given the costly implications of consuming during those hours, Class A consumers reduce consumption in more than just the top five days. This behaviour was prevalent in 2016 (see Figure 2), when there was less certainty around which hours would ultimately make up the five peak demand hours. As a result, directly-connected Class A consumers reduced consumption during a greater number of days (days 6 through 30) compared to years past.[8]

3.2 Impact of the Allocation of the Global Adjustment

As Class A consumers reduce their consumption during peak demand hours and, by extension, the Global Adjustment they pay, the Global Adjustment payable by Class B consumers increases. The resultant shifting of Global Adjustment costs from Class A to Class B consumers has had a significant impact on the effective electricity price paid by both consumer classes. Figure 3 displays the annual Global Adjustment costs shifted from Class A to Class B as a result of participation in the ICI.

[8] In some years, the days containing peak demand hours have been consecutive and easier to predict, resulting in less peak-reducing behaviour outside of those days. In recent years, Ontario has been a summer-peaking jurisdiction, with the peaks typically set during the hottest weekdays in the summer, when air conditioning usage is at its highest. For example, in both 2011 and 2013 the five peak demand hours occurred on consecutive days in the midst of an intense heat wave. Both of these episodes were in mid-July, thus there was little reduction in consumption during the lesser demand days that followed. In the summer of 2016, the 10 highest demand hours occurred over four different weeks from July to September, and this uncertainty induced consumption reductions during hours outside of the days containing the five highest peak demand hours (seen in Figure 2). The expansion of Class A adds further uncertainty around predicting peak demand hours. As more consumers are added to the class, ICI-related demand reductions increase, potentially shifting when the peak demand hours occur. In other words, Class A consumers need to predict the response of other Class A consumers to correctly identify the five peak demand hours.

Figure 3: Global Adjustment Costs Shifted from Class A to Class B Consumers 2011 – 2017 ($ Millions)

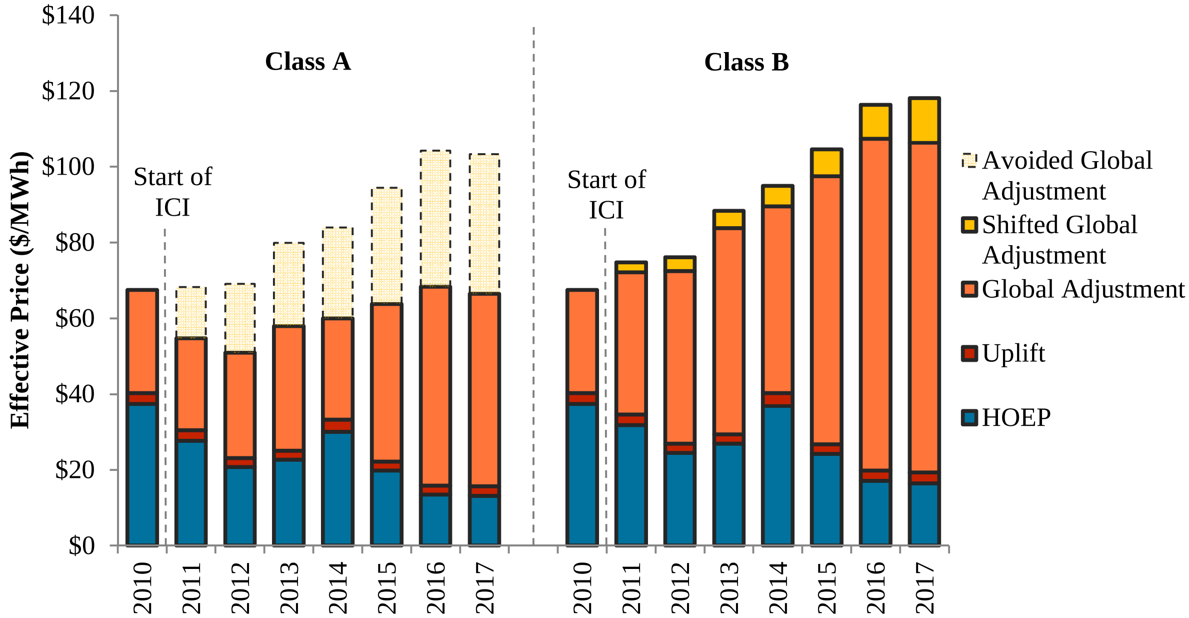


The amount of Global Adjustment costs shifted from Class A to Class B consumers has increased every year since the introduction of the ICI. In 2011, approximately $300 million in Global Adjustment costs were shifted from Class A to Class B consumers as a result of participation in the ICI, representing approximately 3.5% of the total electricity supply costs for Class B consumers that year. In 2017, the costs shifted had increased to $1.2 billion, representing approximately 10% of the total electricity supply costs for Class B consumers. Since 2011, participation in the ICI has shifted a total of $4.91 billion in Global Adjustment costs from Class A to Class B consumers.[9]

Figure 4 displays the average effective electricity price paid by Class A and Class B consumers since 2010, the year prior to the introduction of the ICI. The effective price is broken down by cost component and shows the Global Adjustment costs avoided by Class A consumers and shifted to Class B consumers as a result of Class A participation in the ICI.

[9] As measured from January 2011 to December 2017. Not adjusted for inflation.

Figure 4: Average Effective Electricity Price by Consumer Class
2010 - 2017
($/MWh)



In 2010, the average effective electricity price for both Class A and Class B consumers was $67/MWh. Since then, the average effective price for Class A consumers has decreased to $66/MWh (1.5% decrease), while the average effective price for Class B consumers has increased to $118/MWh (76% increase). In 2017, through participation in the ICI, Class A consumers were able to reduce the average price they pay by $37/MWh. The resultant shift in Global Adjustment costs added approximately $12/MWh to the average price paid by Class B consumers in that same year, representing 24% of the total increase since 2010.[10]

In light of the expansion of the ICI and the increased number of consumers that are eligible for Class A, it is reasonable to expect that the Global Adjustment costs shifted from Class A to Class B consumers will continue to increase.

4. Criteria for Effective Cost Allocation

The Panel recognizes that finding an appropriate balance between competing objectives and interests when allocating costs is challenging. When evaluating the ICI and other methodologies

[10] The per megawatt-hour effective price increase for Class B consumers is smaller than the corresponding decrease for Class A because Class B consumes far more electricity, spreading the cost over more megawatt-hours.

TAB C

EB-2019-0242

ONTARIO ENERGY BOARD

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO)

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

AFFIDAVIT OF COLIN ANDERSON

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

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

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

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

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

The Amendments.

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

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

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

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

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

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

TAB D

receive more profits as compared to resources that clear near the final auction price. Typically a number of auction participants are not price competitive, do not clear the auction and do not receive an obligation to supply capacity.

32. DRA participants who have incurred a DR capacity obligation through the DRA receive a monthly payment for every month of the commitment period for being available to supply capacity if called upon (referred to as an availability payment).

D. How are DRA resources activated or called upon?

33. All DRA resources are expected to be available to reduce their consumption during the summer commitment period from 12:00 to 21:00 EST, and during the winter commitment period from 16:00 to 21:00 EST.

34. Dispatchable load resources are activated (dispatched automatically by the IESO's Dispatch Scheduling Optimization software) on a 5-minute interval if the bid in the energy market is economic, either to meet Ontario's provincial need or a local energy need.

35. HDR resources have restrictions on their ability to be reduce consumption so they require a standby notice from the IESO at any time between 15:00 EST day-ahead up to 07:00 EST on the day of. HDR resources that are on standby can then receive an activation at least two hours in advance for one to four hour hourly blocks of reduced consumption – and only if they are economic compared to other resources for the hour(s) they are activated. HDR resources can only receive one activation per day.

E. What's the frequency for the activation of DR resources under the DRA?

36. DRA participants have been activated in the energy market in very limited circumstances since the DRA was launched in 2015. This is likely due to the relatively high prices at which DRA participants have bid into the energy market.

37. During this period, the Hourly Ontario Energy Price (**"HOEP"**) has averaged approximately $25/MW. During the same period, dispatchable load bid prices have averaged approximately $1500/MWh and HDR bid prices have averaged approximately $1700/MWh.

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

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

PART V - ENERGY PAYMENTS FOR DR RESOURCES

A. What are energy payments for DR resources?

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

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

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

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

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

---

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

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

TAB E

15. I am informed by AMPCO members and verily believe that in the existing DRA process, an IESO proposed “work-around” has sometimes been used. In that “work-around” DR Resources have increased their capacity offers by an amount sometimes referred to as a “utilization payment”. This “utilization payment” is thought of as a partial proxy for energy payments upon activation. Inclusion of this proxy allows the DR Resources to offer a price that would provide them with some compensation if they are activated for energy. If this proxy methodology were to be used by DR Resources in the TCA it would increase their offers and make them uncompetitive relative to the generators.

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

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

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

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

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

TAB F

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.

TAB G

connected generating capacity. Assuming that the ICI alleviated the need to procure additional grid-connected generating capacity, it has not necessarily increased long-term efficiency.

The ICI creates an incentive for Class A consumers to invest in new generating or storage capacity located at their facilities. On-site generation offsets consumption from the transmission or distribution grids, allowing Class A consumers to continue their operations during peak demand hours while simultaneously benefiting from the reduction in Global Adjustment charges. Investing in on-site generation has become increasingly economic as the Global Adjustment has increased: building an on-site generator has an annualized cost of approximately $105,000/MW to $135,000/MW, while operating that generator during all five peak demand hours in 2016 would have saved a Class A consumer approximately $520,000/MW in Global Adjustment costs.[13]

Information on exactly how much on-site generation or storage has been built in response to the ICI is not readily available. Nevertheless, there is some evidence that suggests such investments are being made. In 2017 and 2018, three Class A consumers made a combined 33 applications to the Ministry of Environment and Climate Change (as it then was) to build a total of 44 MW of natural gas-fired capacity.[14] One of the express purposes for which this new on-site capacity is being built is "peak shaving", which in turn suggests the purpose is, at least in part, to reduce Global Adjustment costs through participation in the ICI.[15]

The ICI has the potential to change – and appears to be changing – the nature of a portion of generation investments in the province: from large-scale, centrally-procured, grid-connected investments to small-scale, privately-funded, on-site investments. This has the benefit of shifting risk from ratepayers (who pay the costs associated with the IESO's supply contracts) to private investors and increasing the reliability of service for those investing in on-site generation. However, there are potential inefficiencies associated with the decentralization of supply planning.

---

[13] Estimates of the cost of building on-site generation are based on the construction of a 5 MW gas-fired generator, amortized over 20 years. These estimates are informed by a 2016 study from the U.S. Energy Information Administration and a 2015 study from the U.S. Environmental Protection Agency.
[14] Pending and approved Environmental Compliance Approvals in the province of Ontario are publicly available at: https://www.ebr.gov.on.ca/ERS-WEB-External/
[15] An August 2018 article notes that, "Ontario's Global Adjustment is creating a behind-the-meter energy storage boom," citing the construction of a 10 MW storage system as a recent example. Peter Mahoney, Utility Dive, *Behind-The-Meter Storage is Booming in Ontario,* available at: https://www.utilitydive.com/news/btm-storage-is-booming-in-ontario/530518/

The decision to centrally procure additional grid-connected capacity should be based on whether that capacity is needed to meet system-wide demand. Conversely, a private enterprise's decision on whether to build an on-site generator is based on their private incentives, not on the supply needs of the system as a whole.

Ontario currently finds itself in surplus supply conditions, yet the incentive to reduce consumption under the ICI has never been stronger. Perversely, the incentive for Class A consumers to reduce peak demand—by investing in on-site generation capacity or otherwise—is strongest when there is ample supply and wholesale market electricity prices are low. As shown in Figure 1, lower market prices result in a higher portion of costs being recovered through the Global Adjustment, providing a stronger incentive for Class A consumers to reduce their consumption during peak demand hours. These conditions may encourage private investment in generating capacity that is not needed to meet system-wide demand. The converse is also true; when supply is tight and market prices are high, the Global Adjustment is smaller and the incentive to reduce peak consumption is lower.

Additionally, investment in small on-site generation capacity may be less efficient than investment in large grid-connected capacity. To the degree capacity was or will be needed, Ontario has a multitude of options available to it, including investments in different generating technologies, demand response, conservation, etc. The IESO also has (or is developing) competitive mechanisms to procure these resources, which uniquely situates it to be able to select the least costly sources of capacity. IESO procurement also benefits from economies of scale, as its investments in large grid-connected capacity may be less costly than many private investments in small on-site capacity on a per megawatt of capacity basis.

Improving long-term efficiency requires a better understanding of how the current allocation of the Global Adjustment is affecting investment in new capacity. To that end, information related to the construction of on-site generation and storage should be gathered. That information can inform decisions about the extent to which the ICI is inducing private investment in unnecessary capacity. If investment is needed, the ICI should not provide a private incentive to build on-site capacity that significantly exceeds the cost of centrally procuring grid-connected capacity, as is the case with the ICI incentive today.

TAB H

EB-2019-0242

ONTARIO ENERGY BOARD

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO (AMPCO)

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

WITNESS STATEMENT

Colin Anderson

November 22, 2019

In my direct testimony I intend to address 3 points raised by the evidence filed by Dr. Rivard.

First, Dr. Rivard's various examples compare i) a DR resource consisting of a behind the meter generation facility which allows the load customer to displace a portion of its demand for energy from the market; with ii) a resource consisting of a load customer who is also a directly connected generator market participant and will participate in the TCA as an non-committed generator.

I take issue with the representativeness of such a comparison. Most DR resources do not include behind the meter generation. When process loads provide demand response, they shut down process equipment which entails incremental costs and associated risks well beyond those which Dr. Rivard presumes for his comparisons.

Second, Dr. Rivard cites U.S. research positing that DR load reductions might actually entail shifting demand to other price periods. Many of the process loads referred to above do not have such spare capacity, and when they provide demand response these represent losses in production which are permanent, not merely shifted in time.

Third, Dr. Rivard suggests that providing a DR resource with capacity payments rewards it twice for the same demand reduction if the resource also participates in the Industrial Conservation Initiative (ICI) peak reduction program. I believe that Dr. Rivard is mistaken about this. It is my understanding that if a DR resource reduces load for the purposes of reducing its peak for ICI calculations, that reduction would by definition be unavailable to the market and the IESO would thus claw back availability payments for the period during which the resource was not available. In fact, if the DR resource was to reduce load during peak ICI months (July, August, January or February), the DR resource availability payment claw-back would occur at a 2:1 ratio.