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Energy-Market Payment Options for Demand Response in Ontario

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Executive Summary

The Independent Electricity System Operator (IESO) is currently discussing whether and how energy market payments for demand response (DR) resource activation should apply in the Ontario market. The IESO asked us to inform ongoing stakeholder discussions about whether and how such payments for DR resources should apply in Ontario. While energy market payments for activations have been an ongoing topic of discussion at the IESO's Demand Response Working Group (DRWG), proposed market rule amendments to enable off-contract, non-regulated dispatchable generators to participate in the capacity auction along with DR resources renewed stakeholder interest in the matter in 2019.[1] Given that payments for DR activations are a complex issue and would represent a substantial change to Ontario's energy market, the IESO initiated a separate stakeholder engagement with a broader stakeholder base to advise on the issue.

This report is intended to support this ongoing stakeholder assessment by informing the following questions:

- What is the history and current status of demand response programs in Ontario?
- What are the economic principles and practical considerations governing demand response dispatch?
- How do other jurisdictions' energy markets compensate demand response energy activations?
- What are the demand response compensation options for Ontario?

Additionally, the report proposes options that the IESO can consider to ensure the full participation of demand response by (1) providing both the appropriate incentives and efficient price signals as well as (2) creating opportunities for demand response resources to submit bids to reflect their true costs.[2]

1. What is the status of demand response programs in Ontario?

Dispatchable loads have been active in the IESO wholesale market since 2002, where they submit bids into the energy market and are dispatchable on a five-minute basis. Demand response resources were also enabled through various programs and contracted procurements that were administered by the

[1] IESO, "Proposed Market Rule Amendments" at MR-00439.

[2] In this report, 'incentive' generally refers to economic incentive that market participants receive. This includes economic signals from items like energy market payments, reductions in Global Adjustment charges, or savings from lower retail electricity charges because of reduced consumption. This incentive is related to but different from just wholesale market price signals, which depend on the ability to receive wholesale electricity prices and in some cases, the ability to reflect true participation costs and contribute to price formation.

now-defunct Ontario Power Authority (OPA). The rules for participation, performance, and settlement varied by program type and were stipulated in contracts.[3]

In 2013, the IESO took over responsibility for administering demand response programs with the goal of integrating existing contracts into a market-based Demand Response Auction (DRA). The DRA has been the sole means of managing demand response contracts in the IESO service area since 2018. The DRA is an annual process in which participants compete for demand response capacity obligations for delivery in two seasonal commitment periods. Participants who clear the auction receive payments for making capacity available in the energy market either as a Dispatchable Load or as an Hourly Demand Response (HDR) resource. The price range for demand response bids allowed under the IESO's auction rules is between $100.00/MWh and $1999.99/MWh.

Even with the same DRA capacity obligations, Dispatchable Loads and HDR resources differ in several ways, including in how they participate in the energy market, how they are activated, and how they are settled. One key difference between these two types of resources is that Dispatchable Loads are scheduled and settled in the IESO real-time (5-minute) energy market and are entitled to receive Congestion Settlement Management Credits (CMSC) in the event that dispatch schedule deviates from market schedule.[4] However, the IESO's upcoming transition to a single schedule (as part of its Market Renewal program) will mark the end of CMSC payments. The new Single Schedule Market will align market prices with dispatch schedules, greatly reducing the need for such "out-of-market" payments by lowering the incidence of resources being dispatched out of merit to address nodal congestion.[5] In contrast, HDR resources, modelled as aggregates of smaller customers, do not receive an energy market schedule. Instead, they are subject to a set of standby and activation notifications based on pre-defined triggers, and their aggregated performance is assessed after-the-fact against a baseline.

Ontario has seen considerable discussion related to whether and how the energy market should offer greater participation incentives to demand response. Demand response participants argue that energy market payments would lead to higher demand response participation, which in turn creates savings due to deferrals of otherwise necessary capacity, transmission, and distribution investments. On the other hand, energy market payments for large customers who are already exposed to wholesale prices would unnecessarily distort market signals, favoring one type of customer over another.

According to an intervenor in a recent Ontario Energy Board proceeding, demand response participants are unable to incorporate in their energy bids any of the fixed costs incurred due to energy curtailment. The report also examines this perspective and explores how demand response can effectively reflect their costs into their energy bids.

[3] Ontario Power Authority, "Demand Response Programs in Ontario," IESO Demand Response Working Group Public Session, April 3, 2014.

[4] Note that current activation rules differ from those under the previous demand response program DR-3, where participants were contracted to provide either 100 or 200 hours of curtailment per year.

[5] The term "out-of-market payment" refers to market settlements that deviate from efficient price signals that reflect the resources' marginal costs and economic dispatch consistent with system conditions.

2. What are the economic principles and practical considerations governing demand response dispatch?

Sections A and B of this report lay out the design and economic principles that should govern the activation of demand response resources and discuss the extent to which these principles prevail in the Ontario context. In general, it is economically efficient to dispatch demand response resources to trigger a load reduction whenever wholesale market prices exceed the DR owner's willingness to pay for continuing to receive power. The marginal incentive to curtail should therefore be equal to a wholesale market price that reflects the marginal system value of any realized curtailments.[6]

Economically efficient DR can take place in the energy market only when participants are exposed to marginal price signals that match bulk system value, including accounting for the differences in system value across time and location. For some participants, such signals are still inadequate as DR participation in the energy market has not yet reached full integration in the Ontario energy market. Customers who participate as Dispatchable Loads are exposed to the uniform 5-minute Market Clearing Price. HDR participants, however, are not scheduled in the energy market nor are their individual contributors settled on a uniform basis. Individual contributors that pay the Hourly Ontario Energy Price (HOEP) are not exposed to 5-minute real-time market prices, but the HOEP tracks market clearing price more closely than the electricity rates paid by (smaller) contributors under Ontario's Regulated Price Plan or under retail contracts with electricity retailers. For HDR contributors who pay the "retail rate," wholesale price exposure is not directly available on an either hourly or 5-minute basis. Further, charges associated with the Global Adjustment tend to dominate consumption decisions whenever they apply for both large and small customers, given the large size of the Global Adjustment compared to IESO energy market prices.

Despite the current barriers, a number of advances in market design, technologies, and business models promise to offer opportunities for a wider deployment and more efficient integration of DR in the Ontario market. The implementation of the Market Renewal Program will offer more energy market integration opportunities through locational marginal pricing and the new financially-binding day-ahead market. Increased deployment of distributed energy resources and electric vehicles will bring both uncertainty and opportunities to the wholesale energy market, including growing quantities of resources that can participate in future energy markets. Taken together, these developments indicate that the province has the potential to activate and enable significant volumes of beneficial energy market participation if it can develop an efficient and suitable model for full energy market participation.[7]

[6] Note that similar economic signals should also apply during periods in which the system can benefit from an increase in consumption during low- and negative-priced periods of surplus baseload generation, which would be particularly attractive for electric vehicle charging. During these periods, the marginal incentive for loads to increase consumption should match the marginal system value achieved by helping to relieve supply surplus events. These incentives for incremental loads will be increasingly important in power systems, like Ontario, that are defined by significant surplus generation events during which wholesale power prices are close to zero or even negative.

[7] Ongoing work by the IESO and stakeholders through a number of initiatives examines the growing opportunities for demand response with increasing levels of distribution energy resources. *See* IESO, "[Innovation and Sector Evolution White Paper Series,]" 2020.

3. How are demand response activations compensated in other jurisdictions' energy markets?

In Section III, we provide a broad overview of key DR issues and the options available for efficiently rewarding DR activations by describing how select jurisdictions around the world design and administer DR programs. If properly implemented, this increase in active DR participation adds value to the bulk power system through improved energy market price formation and giving greater visibility to system operators.

However, there are substantial differences among jurisdictions in how DR is compensated for participation, particularly regarding the amount that DR resources should be paid for dispatch. This amount ranges from no payment beyond avoided cost (Alberta), to payment based on Locational Marginal Prices minus the generation component of the retail rate (LMP minus G) (prior U.S. model), to full LMP payment subject to benefits test (current U.S. model), to value sharing with customers (Singapore), and a wholesale purchase and buyback model (proposed in Australia). There is an economic rationale behind each of these approaches, some of which we find more compelling than others. We find that the models used in Australia, previously in the U.S. (LMP minus G), and Alberta all offer similarly efficient economic signals. Of these, the Australia (purchase and buyback) and prior U.S. (LMP minus G) models offer a greater practical value for efficiently enabling DR development.

To date, other markets have generally focused on opportunities for DR to add value through curtailment, giving relatively little to no attention to the question of how to offer activation incentives for increased consumption during low or negative hours. This often-overlooked aspect of energy market participation would be particularly relevant to the Ontario market given the high incidence of surplus baseload generation (SBG) events and negative pricing. Improved incentives during low- and negative-priced hours can help the IESO take advantage of the anticipated increase in the adoption of electric vehicles to maintain system reliability.

4. Recommendations: Immediate Questions Raised by Stakeholders

The IESO has made a number of advancements over recent years to enable and support demand response to participate in the wholesale markets. At the same time, the pace of technological and industry advancement in the area of customer responsiveness potential will present many more opportunities to offer beneficial services to customers and the grid that are not yet enabled by current market rules. To enable demand response players to participate more fully in the wholesale energy market, we believe that additional compensation models should be offered within the wholesale energy market to facilitate the full participation of demand response. These compensation models should send the right signal to reduce consumption during high-priced (especially system scarcity) events—and to possibly also increase consumption during low-priced (especially surplus baseload generation) events. These price signals should not over-compensate demand response providers beyond the marginal value they provide to the system.

In pursuing that outcome, **we <u>do not</u> recommend adopting a customer benefits test and full-wholesale-price payments** approach similar to what has been adopted in most U.S. markets under FERC Order 745. We recommend against the FERC model for three reasons. First, the model over-incentivizes curtailments relative to marginal system value. Second, a customer-benefits test implies a preference for transfer payments from suppliers to consumers, rather than taking a societal benefits perspective that is more consistent with competitive wholesale markets. Third, the U.S. customer benefits test approach does not meaningfully transfer to the Ontario context given the dominant role of the Global Adjustment. Customer cost reductions from energy price reductions are offset on a nearly one-to-one basis by customer cost increases from Global Adjustment charges at all price levels, with large Class A customers more likely to earn a net benefit, but at the expense of smaller Class B customers.

To provide efficient curtailment incentives during periods of high wholesale market prices for retail customers who are not already exposed to the full wholesale market price, we recommend awarding additional payments to demand response for any wholesale energy market curtailments. The payment would be consistent with providing incentives equivalent to the incremental system value. Such payments for energy market participation can enable more market participation, greater development of the demand response market, more system flexibility, and greater overall value. We recommend offering either one or both of the following wholesale energy compensation models for HDRs withThis demand response contributors who are not already exposed to the IESO's wholesale price:

- **Retail Purchase and Wholesale Sellback** (similar to the Australian proposed approach) in which the contributor's settlement would be separated into two components with: (1) a retail purchase, for which the IESO would charge customers or LDCs at their baseline (pre-curtailment) energy consumption; and separately (2) a wholesale sellback, for which the IESO would pay the registered DR market participant for the curtailed MWh at the full wholesale energy market price.
- **Curtailment Payments at the Wholesale Price minus the Generation Component of Retail Rates** (similar to the 'LMP-G' previously used in the U.S.) in which the contributors or the LDC would be charged at their post-curtailment realized consumption, and the demand response provider would be compensated at the wholesale price minus the variable (generation) component of the customer's retail bill ("Wholesale Price minus G").

Both of these models offer economically efficient economic signals for demand response curtailment and energy market participation.[8] Because there is no IESO energy settlement associated with HDR resources—and no uniform settlement of underlying contributors—and a limited retail sector, we recognize that significant changes would need to be considered in order to implement either option in Ontario. Overall, we recommend the *Retail Purchase and Wholesale Sellback* model, as it offers the most promising avenue to enable economically efficient market participation for the widest range of demand response resource types and business models.

Additionally, we find that for some types of demand response resources, the value of lost load (VOLL) is most naturally reflected by the sum of (1) fixed (including 'shutdown') costs expressed in dollars per MW or dollars per activation; plus (2) variable costs expressed in dollars per MWh. Currently, offer prices in Ontario can only include a dollar per MWh component, which means that demand response players face uncertainty in the proper way to offer due to the uncertainty in the duration of the activation event. A

[8] Developed for load reductions, these two models can also be modified to provide economically efficient incentives to increase consumption during (or shift consumption to) low- and negative-priced periods.

resource with $300/MW in shutdown costs and $500/MWh in variable costs should offer into the market (and set prices) at $575/MWh for a four-hour event or $1,700/MWh for a 15-minute event. We recommend that offer prices, dispatch, and wholesale price formation, should account for both types of resource costs.[9] We recommend allowing demand response to bid both types of costs separately, and adjusting price formation to account for both variable plus shutdown costs (divided by event duration) explicitly. If this is not feasible, we recommend a second-best alternative by either: (1) enabling demand response to incorporate both types of costs into their offer price in dollar per MWh (which would maintain the problem of unrecovered costs associated with uncertain event durations); or (2) introducing a make-whole payment to compensate for any unrecovered shutdown costs (which would address the current problem of unrecovered costs, but introduce the new problem of an out-of-market payment).

5. Broader Recommendations for Fully Enabling Demand Response in the Energy Market

Beyond the above recommendations, we find there are a number of ways that demand response can be incorporated into the energy market more fully. While the following recommendations may not directly address stakeholders' immediate concerns and, while they may be challenging to implement in the near term due to the scope of work involved, they may help to enhance demand response participation in the future.

- **Align demand response resources' dispatch signals and settlements with day-ahead and real-time LMPs** (post Market Renewal; or using the currently used nodal "shadow prices"). If adopted, our recommendations would lead to more demand response sellers offering into the energy market at their private value of energy consumption (*i.e.*, private cost of voluntary curtailment). We recommend that these resources should be dispatched if (and only if) the marginal system value of energy (*i.e.*, the nodal day-ahead or real-time price) exceeds the resource's private offer price. This would ensure that demand response is called only when it is the least-cost resource available to the system, which preserves incentives to offer at the true resource cost. To reduce the frequency of out of market dispatches, we recommend identifying any instances of such out-of-market DR dispatch and evaluate whether these can be transitioned into a system of market-based dispatch against day-ahead or real-time LMPs (after Market Renewal) or the nodal "shadow price" (under the current two-schedule market). Currently Dispatchable Loads are eligible for CMSC payments whenever their dispatch schedule deviates from their market schedule. There is no similar basis for HDR, in part because there is no energy settlement. However, both HDRs and DLs are compensated for certain non-market dispatch instructions, such as during system emergency events. However, even during emergency events DR resources should not be activated until prices reach their offer price (which may often be the price cap). (We recognize that out-of-market test activations for the purposes of capacity market participation will still be necessary if energy market prices are not high enough to trigger a sufficient number of in-market activations.)
- **If DR dispatches at settlement prices below DR dispatch costs cannot be resolved in the near term, offer make-whole payments for any such out-of-market dispatch** (while working to reduce the

[9] In PJM, the system operator addresses this issue by allowing demand response to submit energy offers in the day-ahead energy market that include shutdown cost, variable cost, and minimum downtime components.

frequency of such events). If our above recommendations are implemented, there would not be any occasions when a demand resource is dispatched at wholesale prices below their offer price. Thus, there would not be any occasions in which make-whole payments are needed. However, we understand it would be challenging to achieve this ideal outcome in the near term. Therefore, we recommend awarding make-whole payments to demand response resources whenever their market payments undercompensate them relative to either system value or relative to their individual resource cost. Before Market Renewal is implemented, this would mean that when activated, HDRs would be paid at the pre-dispatch nodal shadow price minus the resource's weighted average HOEP-based wholesale settlement price in that event. For any out-of-market dispatches or test activations, we recommend to compensate the resource an amount equal to the differences between the resource's offer price and market prices. After Market Renewal, we anticipate many of these make-whole payments could be eliminated with the introduction of a day-ahead market and locational pricing. However, make-whole payments should continue to the extent that: (1) demand response is dispatched against nodal prices but loads are settled at lower zonal prices; (2) demand response is economically activated in pre-dispatch but settled at lower real-time prices; or (3) demand response is dispatched on a non-market or test basis when prices are below their offer price.

- **Incorporate demand-resource offer prices into energy market price formation.** The corollary to the prior recommendation is to ensure that demand response resources' offer prices can contribute to energy market price formation at all timeframes and locations. This will improve the ability of wholesale prices to signal times and locations of system stress, thereby signaling demand response and other resources to react. Currently DLs can contribute to real-time price formation but only when they are dispatched against the five-minute Market Clearing Price (as opposed to for reliability reasons). HDR resources can similarly contribute to pre-dispatch price formation. However, in practice in Ontario (and other markets), most demand response dispatches have the undesirable effect of artificially suppressing market prices right when high prices are most needed. This occurs because out-of-market DR dispatches cause the pricing software to perceive lower system demand and thus produce a lower clearing price than it would if the DR offer price had been integrated into both dispatch and price formation. We recommend correcting this underpricing issue and restore market prices to a level at or above demand resources' offer prices whenever they are dispatched. Prior to Market Renewal, this would primarily mean ensuring that the marginal cost of any emergency-based or pre-dispatch-based demand response dispatches driven by system-wide shortages can be incorporated into the real-time market price and the HOEP. After Market Renewal, this would further extend to include any demand response dispatches driven by day-ahead conditions, zone-level congestion, and node-level congestion. Achieving this outcome will be challenging given the unique dispatch timeframes and characteristics of individual demand response resources that may prevent full incorporation into real-time security-constrained economic dispatch (SCED), but other markets such as PJM have adopted reasonable approaches.[10] Allowing for

10 *See* ISO market manuals for a discussion of demand response scheduling in energy markets.

PJM, "PJM Manual 11: Energy & Ancillary Services Market Operations," December 3, 2019 at 124.

MISO, "Business Practice Manual 2," 2018 at 58.

participation in the day-ahead market is important because, just like certain generating resources that are dispatched mostly on a day-ahead basis, not all DR resources will be able to respond to real-time dispatch signals.

- **Increase energy market price cap and adjust ancillary service shortage pricing consistent with the value of lost load (VOLL) for involuntary curtailments.**[11] Today, many demand response players in Ontario (and elsewhere) offer into the energy market at just below the maximum allowed offer price of $2,000/MWh. It is likely that at least some of the cap-based offers indicate that customers value their energy consumption at a price that exceeds the current price cap.[12] We recommend increasing the energy market price cap and adjusting ancillary service market scarcity pricing parameters to levels that are consistent with realistic estimates of VOLL in Ontario. For example, Texas uses a value of USD $9,000/MWh (CAD $11,898)[13] and the MISO market monitor recommended that scarcity prices should be able to reach a VOLL of USD $12,000. Allowing scarcity prices to reach these levels will ensure that reliability is not undervalued and that demand response can be induced to address reliability problems before they require involuntary load shedding. Because these shortage and near-shortage events are rare, increasing the price cap would have a negligible effect on average wholesale prices; however, proper pricing during such events would offer significant benefits by inducing more efficient system operations and investments.

Adopting these recommendations could address some current challenges to the full and efficient integration of demand response into Ontario's energy market. Ontario has the potential to develop increasing quantities of demand response using technologies and business models that are emerging or may not exist today. While implementing these recommendations could be challenging in the near term, they would help integrate existing demand resources more effectively and increase the market's flexibility to evolve with economic conditions and technological progress. Taken together, these recommendations would help to create a market and regulatory environment that would further foster the efficient development of the technologies and business models.

ISO-NE, "ISO-New England Manual for Market Operations," Manual M-11, April 7, 2017 at 2-9.

11 Maintaining a price cap equal to the value of lost load during scarcity events will provide efficient signals for generators and demand response participation.

Samuel A. Newell *et al.*, "Estimating the Economically Optimal Reserve Margin in ERCOT," January 31, 2014.

Johannes P. Pfeifenberger and Kathleen Spees, "Evaluation of Market Fundamentals and Challenges to Long-Term System Adequacy in Alberta's Electricity Market," April 2011.

12 Bids at the cap may be due to reason other than high curtailment costs, such as attempts to attract a high CMSC payment when curtailed or as a means of avoiding risks associated with a dispatch performance penalties.

13 "2018 State of the Market Report for the ERCO Electricity Markets," Potomac Economics, June 2019 at 19.

I. What is the Status of Demand Response Programs in Ontario?

A. EVOLUTION OF ONTARIO DEMAND RESPONSE PROGRAMS

Demand response is designed to reduce consumption during periods of system peak demands. In Ontario, this reduction can be provided by either dispatchable loads or designated demand response resources that can be dispatched by the IESO. The history and current status of each of these resource types are described below.

Dispatchable load resources submit bids into the energy market and are dispatchable on a five-minute basis. The energy bid is meant to represent the dispatchable load's price, above which, they would rather stop consuming electricity. These resources have been active in the IESO-administered energy market since market opening in 2002. Refer to **Table 9** in the Appendix for a description of how dispatchable loads participate and are settled, as well as applicable details from the Market Renewal Program.

Starting in or about 2005, the former Ontario Power Authority (OPA) commenced a number of demand-side programs to acquire demand response resources. These programs included DR-1, DR-2, DR-3 and Peak Saver.[14] These programs are no longer operational; however, the DR-3 program is still relevant given its linkages and evolution to the current IESO's Demand Response Auction and thus described further.

As part of the DR-3 program, participating commercial and industrial facilities were required to have a minimum annual peak demand of 5 kW. Facilities with annual peak demands of 5 MW or greater entered into contracts directly with the OPA, and those with peaks under 5 MW entered into contracts with a DR aggregator. DR-3 participants had to be available between 12–9 p.m. from June through September weekdays and 4–9 p.m. during non-summer weekdays, and were contracted for either 100 or 200 hours/year during which they could be dispatched to reduce their load in (in a maximum of 4 hour segments per activation). For these commitments, DR-3 participants received a monthly availability payment in return for being available to reduce load when called upon, and a utilization payment of $200/MWh for activations.

DR-3 resources were activated using a two-step standby/activation notification process. Standby notifications were sent day-ahead or day-at-hand (no later than 7 a.m. EST) if: (a) a metric called the

[14] IESO, "OPA Demand Response Programs," January 17, 2011.

The DR-1 program was started in 2007 but is no longer active. This voluntary, event-based buy-back program was triggered by market prices. Commercial and industrial facilities could test their load reduction capabilities. As a load-shifting program, DR-2 targeted large industrial facilities that were contracted to shift a specific amount of load from peak to off-peak hours. The program was canceled due to low enrollment. The DR-3 program offered aggregators or direct participants payments for being available to provide load reductions. Peaksaver was a voluntary direct load control program, in which residential and small commercial facilities would reduce energy consumption of their central air conditions system during hot peaking summer days.

"supply cushion value" was below a threshold in any hours of the availability window, and (b) the forecast market price for at least one hour within the availability window was above the floor price trigger. The supply cushion trigger was updated monthly by the OPA, and the floor price triggers were calculated and updated weekly by the OPA. Activation notices were sent out only after a prior standby notification and no later than 3 hours prior to any activation event. Activation notices were issued if: any hourly supply cushion values within the dispatch period was below the threshold and the forecast market price for at least one hour in the dispatch period was above the floor price. From 2008 to 2012, DR-3 resources who committed to 200 hours/year were dispatched 44 times, and those who committed to 100 hours/year were dispatched 31 times.[15]

In 2013, the Ministry of Energy published its Long-Term Energy Plan, which encouraged development of DR in Ontario and transferred responsibility of the demand response programs to the IESO with the goal of integrating existing contracts into a market-based program. With this direction, the IESO created the Demand Response Auction (DRA). To bridge the period from the DR-3 contract expiration to the delivery date of the first DRA, the IESO developed a transitional demand response program called the Capacity Based Demand Response (CBDR) program. The CBDR program continued some aspects of the OPA DR-3 programs, while simultaneously harmonizing them with the IESO DR-auction Market Rules.[16] For example, the CBDR program included the $200/MWh fixed rate utilization payment, but this payment was eliminated upon the expiration of the DR-3 contracts, as was the contract provision requiring the resources to commit up to 100 or 200 hours/year during which they could be activated.[17] The last of the CBDR contracts expired in 2018.[18]

The DRA procures demand response capacity annually for two seasonal commitment periods per year.[19] The IESO sets a target capacity for each DRA, which was historically informed by a policy target for demand response penetration levels, but in the future will be based on the quantity of supply needed to meet resource adequacy needs. Participating demand response resources compete for obligations to fulfill these capacity needs. Participants who clear the auction must make their capacity available by offering it into the energy market during the availability window to receive availability payments. Demand response resources receive availability payments, but do not receive payments when activated to curtail load; however, they do avoid paying for the reduced portion of the load.

DR participants with capacity obligations must offer a demand response energy bid of at least $100/MWh and at most $1999.99 into the wholesale energy markets, either as a Dispatchable Load or as an Hourly Demand Response resource (HDR).[20] Unlike Dispatchable Loads, HDRs have no real-time energy market

15 Freeman, Sullivan & Co., "Options for Integrating DR Programs Into Ontario Markets and Grid Operations," (2014).

16 "IESO's Responses to OEB Interrogatories in Application to Review Amendments to the Market Rules made by the Independent Electricity System Operator #6," proceeding EB-2019-0242. (2019)

17 Utilization payments were canceled in part because in the new program, DR resources can now signal their curtailment costs through energy market bids.

18 Ibid., 2.

19 IESO, "Market Manual 12: Capacity Auctions, Part 12.0: Demand Response Auction," Issue 7.0, October 2019 at 7 ("Part 12.0: Demand Response Auction").

20 An HDR with IESO-registered revenue metering is called a physical HDR resource. Otherwise, it is virtual HDR resource. IESO, "Part 12.0: Demand Response Auction," at 7.

schedule. Instead, they are 'activated' for a time block up to 4 hours. Please refer to **Table 9** in the Appendix for further description of HDR resources participation criteria in the energy market and their settlement. According to IESO, HDR resources usually offer closer to the $2,000/MWh ceiling in the energy market. In more than 70% of cases, Dispatchable Loads bid $1,990/MWh and up. HDR resources do receive a payment when they are activated for testing or during an emergency operating state because these are activations that cannot be avoided through energy bids (*i.e.*, they are out-of-market activations).

There are a number of participation, activation, and settlement differences between Dispatchable Loads and HDR resources with DRA capacity. These differences are described in **Table 9**. One notable difference between Dispatchable Loads and HDR resources is that the former is scheduled and dispatched in the real-time energy market, and it is entitled to Congestion Management Settlement Credits (CMSC) whenever their dispatch schedule differs from their market schedule. In contrast, HDR resources are modelled as aggregates of smaller customers, and they do not have real-time dispatch. HDR resources are placed on standby if pre-dispatch (PD) shadow price in their location exceeds $200 per MWh in one of the hours of availability by 7 A.M. of the dispatch day. Once on standby, HDR resources are activated when the shadow price is greater than the bid price three hours before dispatch (i.e., in "PD minus 3"). Additionally, HDR resources do not have energy settlements with the IESO. Further, an HDR resource typically consists of potentially dozens of smaller resources, as opposed to a single underlying contributor.

Finally, we note CMSC payments will no longer apply under Market Renewal, as the IESO will be moving to a single schedule market (SSM) with Dispatchable Loads settled at nodal prices. However, HDR resources' underlying contributors will continue to be settled on uniform, zonal, or retail/RPP rates (rather than LMP).

Current DR Participation Levels

The IESO launched its first DRA in December 2015, with about 391 MW procured for the summer of 2016.[21] Since then, the amount of capacity through DRA capacity has steadily increased, with a total of 810 MW procured for Winter 2019/2020.

Historically, demand response resource activation has been infrequent. Since the start of the program in 2016, Dispatchable Loads have been dispatched less than 1% of the time.[22] Over the same period, HDR resources were activated only for a period of three hours in total (in July 2019). The IESO's short-term forecast for capacity need indicates that economic demand response activation will remain infrequent in the near future. Going forward, the IESO plans to expand the DRA into a more comprehensive capacity auction that requires demand response and other technologies to compete on a level playing field.

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21 IESO, "Demand Response Auction: Post-Auction Summary Report," December 10, 2015.

22 "IESO'S Responses to OEB Interrogatories in Application to Review Amendments to the Market Rules made by the Independent Electricity System Operator #8," *proceeding EB-2019-0242*.

Discussions on the Value of Energy Market Activation Payments

Whether demand response participants should be compensated beyond availability payment to include energy market payments for activations is an increasingly important topic that has attracted a significant level of attention in recent years.[23] As described in Navigant's *Demand Response Discussion Paper: Utilization Payments*, demand response proponents argue for energy activation payments because:

- Energy market payments for activations can increase demand response participation, which in turn obviates the need for more expensive generation resources, including new peaking generation capacity.
- Generation resources do receive a payment when they produce electricity—a form of energy market payment. Demand response resources, therefore, should receive consistent treatment when they curtail consumption.
- Retail prices are insulated from wholesale market pricing; therefore, they reflect neither real-time market conditions nor the true cost of electricity. Customers on regulated price plans in particular are not exposed to wholesale market price signals.
- Curtailments of loads could impose economic losses. This value of lost load (VOLL) should be weighed against the cost of producing a MW of electricity for a load.

The Navigant report also identified key arguments from market participants who do not favor energy market payments for activations:[24]

- The wholesale market is already efficient; price-responsive loads can determine whether it is more cost-effective to operate or curtail based on the existing market price signal.
- Energy market payments would disproportionately compensate demand response because demand response resource did not incur a cost associated with the production of electricity.
- Energy market payments may lead to inefficient level of demand response participation, which in turn can put downward pressure on wholesale energy prices, reducing the profitability of other supply resources.

After the publication of the Navigant report, the IESO deferred the question of whether energy payments for demand response activations should proceed. As this matter has gained importance again—in part because of current plans to expand the DRA to include generating resources and other capacity resources—the IESO has started a stakeholder initiative. This initiative also overlapped with an Ontario Energy Board (OEB) proceeding related to the IESO market rule amendments that would allow off-contract generators to participate in the December 2019 Capacity Auction. The Association of Major Power Consumers in Ontario (AMPCO), which represents large loads, asserts that the amendments are

23 Navigant, "Demand Response Discussion Paper: Utilization Payments," Prepared for IESO, December 18, 2017.

24 Ibid.

discriminatory because demand response participants do not receive energy payments.[25] In its January ruling, the OEB did not find sufficient evidence of discrimination and allowed the amendments to proceed.[26]

It is in this context that we are providing these analyses and recommendations on the most efficient path forward.

II. What Are the Economic Principles and Practical Considerations Governing Demand Response Dispatch?

A. DESIGN PRINCIPLES FOR ENABLING RESOURCE-NEUTRAL PARTICIPATION IN ENERGY MARKETS

One of the overarching objectives detailed in *The Electricity Act of 1998* is "to provide generators, retailers, market participants and consumers with non-discriminatory access to transmission and distribution systems in Ontario."[27] Consistent with the spirit and letter of the *Electricity Act*, the IESO's market rules are aimed to promote "an efficient, competitive and reliable market for the wholesale sale and purchase of electricity and ancillary services in Ontario."[28] These objectives align with underlying economic concepts that drive efficient markets, where prices should be consistent with marginal system value for all products, at all times, and all locations. These markets should enable suppliers and customers alike to supply these products and manage their demand, respectively, in ways that collectively help meet system needs at low cost.

More recently, the IESO expanded on these objectives during the development of the Market Renewal Program and identified five guiding principles.[29] **Table 1** enumerates these principles and describes their implications for demand response.

25 Demand response providers propose the adoption of the FERC model, where demand response receives full LMP energy payments. *See* Section B. of this report.

26 Concerns related to shutdown costs that demand response incurs surfaced over the course of the proceeding. We will address these concerns in Section 2 of this report.

27 Electricity Act, 1998 S.O. 1998, Chapter 15 Schedule A (1)(e), Ontario, Canada.

28 IESO, "Introduction and Interpretation of the Market Rules," issued June 1, 2016.

29 IESO, "What is the Market Renewal Program," 2019.

TABLE 1: GUIDING PRINCIPLES FOR MARKET RENEWAL PROGRAM

Principle	Mechanism	Implications for Demand Response
Efficiency	Lower out-of-market payments and focus on delivering efficient outcomes to reduce system costs	• Demand response should have equally efficient incentives to dispatch whenever market prices exceed the participant's willingness to consume
Competition	Provide open, fair, non-discriminatory competitive opportunities for participants to help meet evolving system needs	• Demand response should have equal access to participation in the energy markets as generation or storage • Demand response's unique business models, technological characteristics and data exchange capabilities should be accommodated to the extent practical to enable all types and minimize barriers to entry
Implementability	Work together with stakeholders to evolve the market in a feasible and practical manner	• Demand response participation should not cause undue administrative burden nor otherwise negatively impact efficient market processes
Certainty	Establish stable, enduring market-based mechanisms that send clear, efficient price signals	• Demand response's willingness to consume should be incorporated into efficient price formation and reflected in dispatch • Demand response compensation must send the same market signal to all types of demand response
Transparency	Accurate, timely, and relevant information is available and accessible to market participants to enable their effective participation in the market	• Wholesale markets should aim to enhance IESO visibility into demand response resources and dispatchability to the extent feasible and efficient

It is through the lens of these guiding principles that we evaluate the different energy market payment options for Ontario. Additionally, we will consider how the different options affect the IESO's ability to sustain excellence in electricity system reliability. Finally, in light of both the emergence of new technologies and the changing relationship between electricity consumers and providers, we will examine how different options may best encourage these developments in the future.

B. THE ECONOMICS OF DEMAND RESPONSE

In a well-designed demand response program, participants respond to the same broad economic incentives as participants in any other market: choosing to curb their consumption when electricity prices are above their willingness to pay (i.e., their private curtailment costs) and to consume more when prices are lower. Private curtailment costs have both fixed and variable components. Current Ontario rules allow energy market bids to reflect the sum of both types of costs. However, the difficult-to-predict duration of activation events poses a challenge when making an accurate advance calculation of these costs to fit the $/MWh format of energy market bids.

Efficient behavior only occurs when the demand response participant is exposed to a marginal incentive that is equal to the signal provided by an efficient wholesale energy market price. If incentives diverge from costs or market prices, inefficient demand response activations (either too many or too few) and higher system-wide costs will be the result.

1. When Do Demand Reductions (or Increases) Enhance Economic Efficiency?

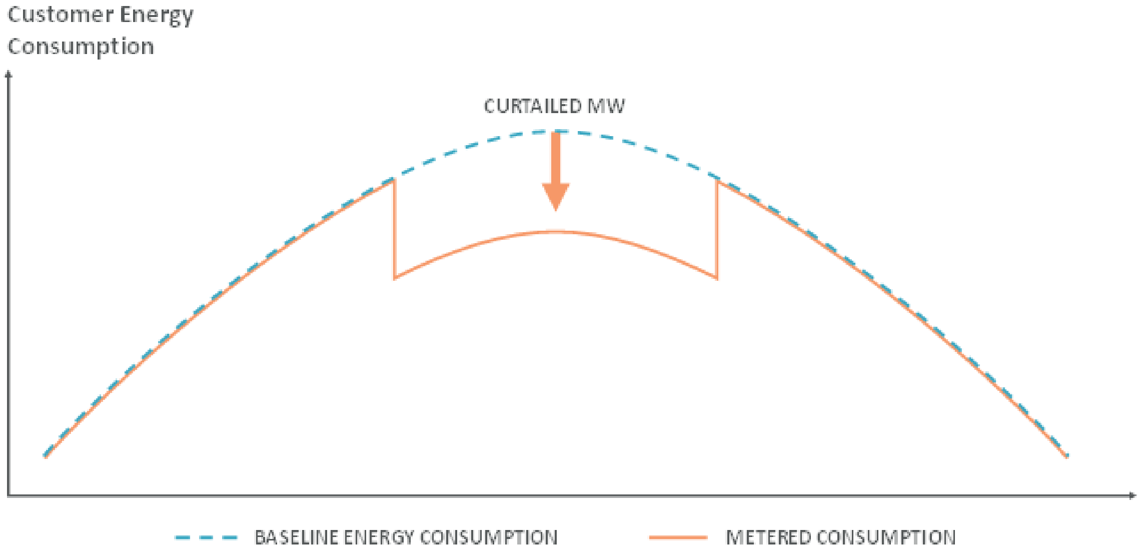
When a market operates optimally, the interaction of generation supply and customer demand sets the price of electricity in an efficient electricity market. Supply should reflect the generator's willingness to sell electricity into the market, given the marginal cost of the resource. Likewise, demand should reflect the customer's willingness to pay for electricity consumption. The demand curve describes the relationship between the unit price of electricity and the total quantity desired by customers. Customers desire less electricity if the price is higher and will tend to consume more if the price is low, causing the demand curve to slope downward. The point at which the supply and demand curves intersect would set the most efficient market price and cleared quantity. One potential outcome of such an efficient market is that customers will choose to consume more when electricity prices are below what their willingness to pay.

Demand response participants subscribe to the same economic incentives. Depending on their private curtailment costs, participants respond to market price and dispatch signals by adjusting their consumption, and the marginal incentive for participants to respond should match the system's marginal value.[30] In a well-designed demand response program, efficient curtailments improve overall system efficiency and reduce overall costs by either replacing high-cost, generation, or relieving high-cost reliability events, through the shedding of lower-value loads. When the electricity system experiences high demand on a hot summer day, it may rely on higher-priced resources that increase wholesale market prices. Under these circumstances, demand response contributors may be called upon to reduce their energy consumption to alleviate the demand pressure on the system. Relative to the baseline amount of electricity they normally consume, demand response contributors will consume less energy during a demand response event, as depicted in **Figure 1**. The difference in these costs is generally an efficiency gain to society shared by some combination of private market participants (such as the demand response provider) and the broader public (through lower energy prices).[31]

[30] The curtailment cost includes both fixed and variable components (*see* the discussion on Shutdown Costs in Section 2 of this report).

[31] The Global Adjustment charge makes changes in efficiency not as straightforward to estimate. Please refer to Section 2 of this report for further discussion.

FIGURE 1: DEMAND RESPONSE CURTAILMENTS DURING HIGH-PRICED HOURS CUSTOMER REDUCES CONSUMPTION WHEN WHOLESALE PRICE EXCEEDS ACTIVATION PRICE



In addition, demand response can enhance economic efficiency by increasing power consumption when prices are low or even negative. Such increases in consumption can help maintain the system's reliability and reduce overall costs in times of excess supply. If the marginal cost of consumption exceeds a customer's activation price, the customer should be incentivized to consume more energy. In a situation of negative market prices, customers like electric vehicle owners should be paid to charge the vehicle's batteries. Although this load-increasing aspect of demand response is not as widely discussed as reductions in demand, it will grow in importance in the future, as large and growing quantities of distributed energy resources and electric vehicles bring more opportunities to the wholesale energy market.

Absent transparent price signals, demand response customers will either not respond or respond inefficiently to prevailing market conditions. Loads, like other market participants, will only respond efficiently if they are exposed to accurate and transparent price signals. Customers who are exposed to wholesale spot prices are able to respond efficiently and, if bid into the market, system operators can efficiently dispatch these loads during times of need.

2. What Economic Factors Do Demand Response Resources Consider in Voluntary Dispatch?

a. Energy Market Payments for Activations

In a perfectly efficient market, demand response contributors would choose to curtail their electricity consumption when their willingness to pay for energy (*i.e.*, their private cost of curtailment) was lower than the wholesale price of electricity.

Suppose a demand response contributor has an activation price of $200/MWh.[32] If the contributor faces an electricity price of $190/MWh, she will continue to consume. This is because the price to consume one additional MWh of electricity cost is $190—below the activation price. In fact, so long as the price of electricity remains lower than the activation price, she will not curtail her consumption. However, if the electricity price exceeds $200/MWh, say $210, the contributor will choose to curtail, because the saving of $210 (from curtailing one MWh of electricity) is greater than her $200 curtailment costs.

This curtailment behavior is efficient only if the contributor is exposed to a marginal incentive equivalent to an efficient wholesale energy market price. The left side of **Figure 2** (below) illustrates the signal that a wholesale price-exposed contributor receives, and why this signal should lead to efficient consumption and curtailment. (However, even with this efficient signal, the wholesale-exposed customer likely may need the support of enhanced enabling technology, business processes, and enabling settlement approaches to activate efficient response behavior).

An even more challenging situation is that many customers in Ontario and other markets are not exposed to real-time wholesale power prices. The right side of **Figure 2** shows how retail rates that do not reflect wholesale prices can distort customers' incentives to curtail their consumption, even if wholesale prices spike to very high emergency levels. Continuing with the example of a $190/MWh wholesale electricity price, the customer in this case instead pays a flat charge of $35/MWh for the energy-market-component of the retail rate.[33] This retail rate does not depend on market conditions in that specific time. As a result, for every curtailed MWh of electricity, the demand response participant only receives $35 in retail cost savings. This arrangement does not incentivize efficient curtailments or changes to the consumption profile when prices are higher than average. Further, this retail rate alone creates no opportunity for a demand response aggregator to enhance value by more actively managing the customer's consumption profile in response to wholesale market prices. The empty gray box on the right side of **Figure 2** depicts the missing incentive as the difference between the wholesale price and the energy-component of the retail rate is $155/MWh. When prices rise to the price cap of $2,000/MWh in Ontario, as should be expected during shortage conditions, the size of the missing curtailment incentive can rise to $1,965/MWh. This means that customers who would gladly shed their consumption of low-value loads if given the proper incentive, but they will never do so, even though they will ultimately still pay for their inactivity through higher average retail rates (albeit on a delayed and averaged basis alongside all other retail customers).[34]

32 The activation price reflects the value that the customer derives from consuming a unit of electricity, including the economic costs associated with forgoing that consumption. In other words, it is the opportunity cost of not using power if the case of curtailment, or the opportunity cost of using more power in the case of increased consumption.

33 Retail customers in Ontario also pay other cost components on a $/MWh or cents/kWh basis, such as for Global Adjustment, transmission, and distribution costs. While the sum of these $/MWh-based charges would be significantly higher than the $35/MWh used in this illustration, the same principle applies: retail rates are based on average costs and do not generally reflect the time-varying cost of generation supply, which during scarcity conditions can be much higher than the average energy components of the retail rate (and even the total variable components of the retail rate, though this occurs less frequently). *See* Section 1 of this report.

34 This example assumes a single demand-response resource that is also the contributor. This may be the case for large industrial customers. However, in reality, many demand response resources consist of aggregates of multiple contributors

FIGURE 2: MARGINAL INCENTIVE TO CURTAIL FOR DEMAND RESPONSE CONTRIBUTORS IN HIGH-PRICED HOUR

Demand response aggregators would be well-positioned to address this missing incentive to respond to wholesale market conditions, if a system of wholesale payments were introduced that afforded positive payments for achieving curtailments during system stress events.[35] The structure and size of the payments offered would need to ensure that the total incentive to respond (including accounting for both retail rates and wholesale prices) aligns with marginal system value if the most efficient level of response is to be achieved.

consisting of customers who pay the HOEP and customers who pay the RPP; class A and class B customers; and customers who are settled by different entities. At the same time, the aggregator submits a single bid without full information on energy settlement arrangements. These factors can complicate these proposed solutions.

35 If the value proposition of actively managing consumption patterns is high enough to the private customer, they may engage in private contracts with an energy services contractor or demand response aggregator to respond actively to wholesale market prices. The demand response contributor and aggregator can then share the value of active management through a private arrangement. However, the transaction costs associated with such an arrangement may be relatively high if the parties must privately agree on a system of baselining and settlements. Further, this arrangement does not achieve the system benefits of full energy market participation, since reacting to market prices does not offer the system operator the visibility, control, or price formation benefits of full participation through energy market offers.

A more valuable arrangement from a system-wide perspective would be one that enables full energy market bidding participation of demand response contributors through aggregation, likely to be achieved only if there is some means of earning positive payments directly from the wholesale markets. A standardized program of wholesale payments that can be earned by demand response (against a vetted baseline) may also reduce private transactions costs by offering a more straightforward opportunity for the contributor and demand response aggregator to ascribe a specific value to demand response activities, which can then be readily shared between the parties. However, if the curtailments were only to be activated at times when price exceeds private willingness to pay, the overall incentive for curtailments would need to remain consistent with wholesale prices.

Similar dynamics take place during oversupply periods as well. Properly designed, demand response programs can help to align the operations of distributed energy resources with real-time system needs, enabling large and growing quantities of resources that can participate in the future energy markets. To the extent that incentives to adjust consumption are efficient and the proper business models are in place (see below), controllable loads could consume more energy in times of excess generation, or shift the time of their consumption.

Economically inefficient responses occur when demand response participants are not exposed to wholesale prices, similar to curtailment during high-priced hours. During negative wholesale prices, the market is willing to *pay contributors* for each MWh of electricity, but they will only consume more if the net benefit exceeds their retail price (instead of activation price). When the retail price does not reflect the surplus–supply conditions in the wholesale power market, contributors do not respond efficiently.

For both positive- and negative-priced hours, demand response contributors who are not exposed to the time-varying wholesale electricity prices, as is the case for HDR contributors that pay RPP or retail rates in Ontario, do not have the incentives to respond in an economically efficient manner by increasing or decreasing their load in response to market prices. Thus, aligning demand response activation incentives with the wholesale market price signal remains a keystone of a well-designed demand response program.

b. Demand Response "Shutdown Costs"

A demand response resource's decision to curtail depends on its private curtailment costs, which can consist of fixed and variable components, as discussed in a recent AMPCO filing before the OEB.[36] Variable costs include expenses associated with the incremental unit of energy curtailed and incurred on a $ per MWh basis that increases with the magnitude and duration of the curtailment. Certain types of demand response can also incur one-time fixed or 'shutdown' costs every time they are activated, regardless of how long the curtailment lasts. The shutdown costs may include labor, operating, or equipment costs. For example, consider a paper mill that must reduce the use of pulp refinery equipment to reduce consumption by 1 MW; after the curtailment the mill must incur labor, fuel, and equipment costs to restart equipment to return to normal consumption after the curtailment event has passed.[37] These one-time shutdown or fixed activation costs may incur $300/MW in expenses (regardless of activation event duration), plus an additional $500/MWh in variable activation costs associated with lost production at the mill, which increase with event duration.

In Ontario, demand response resources are currently able to reflect both components of their activation costs in their energy market bids, determining the best way to do so is not straightforward if they cannot

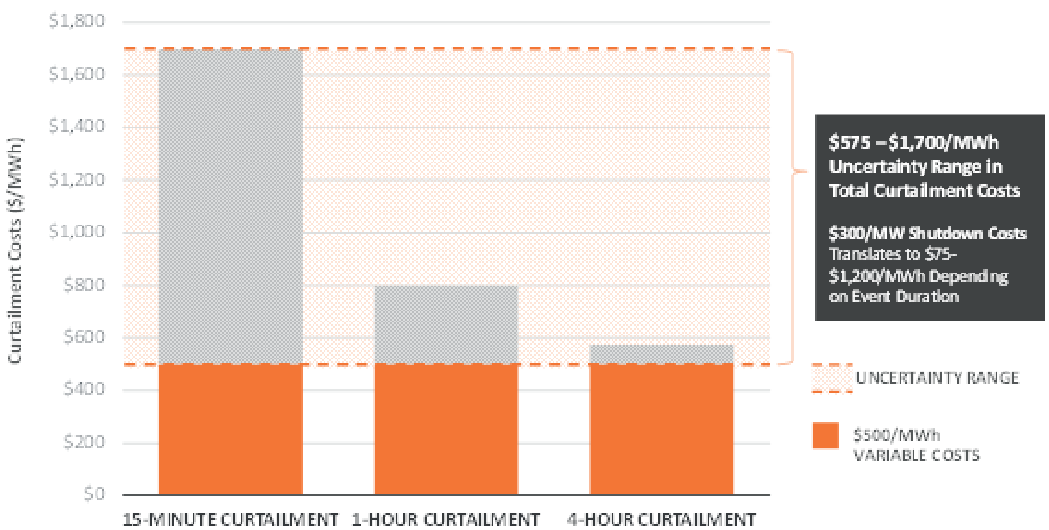
[36] Note that AMPCO has referred to the fixed component of activation costs as "shutdown costs" and the variable component of activation costs the VOLL. For the purposes of our discussion in this report, we term these components to be the fixed/shutdown cost and variable cost, and collectively refer to these combined costs as the VOLL.

AMPCO, "Summary of Final Argument," EB-2019-0242, December 2019 at 2.

[37] Not all demand response participants have shutdown costs. Demand response aggregators for which activation would mean changing the settings on a supermarket freezer or dimming the lights in a hotel lobby may incur no shutdown costs.

accurately predict the duration of an activation event. This uncertainty is illustrated in **Figure 3** for the resource with a $300/MW shutdown cost plus $500/MWh variable curtailment cost. If the curtailment is to last four hours, the mill should bid at an energy price of $575/MWh (with shutdown costs amortized over a four-hour event window). If the curtailment will last only 15 minutes, the mill should bid at an energy price of $1,700/MWh (with the same shutdown costs amortized over a much shorter 15-minute event window).[38] Unless the demand resource can exactly predict the event duration, they will face one of two uneconomic outcomes. The event will be either: (1) shorter than expected (meaning that shutdown costs will not be fully recovered), or (2) longer than expected (meaning that the resource may not be called on for dispatch even though prices are higher than the customer is willing to pay to continue operating over the extended period). These issues are even more complicated for demand response aggregators who work with multiple contributors. The aggregator may submit only one bid, though the underlying contributors may have many differently fixed costs.

FIGURE 3: UNCERTAINTY IN TOTAL CURTAILMENT COSTS FOR DEMAND RESPONSE WITH SHUTDOWN COSTS



The inability to recover their shutdown costs when activated may put demand response aggregators at a disadvantage relative to generators. In the OEB proceeding, AMPCO points out that, while generators under the IESO's Generator Cost Guarantee program receive reimbursement for any unrecovered start-up costs, demand response resources do not receive similar compensation when activated.[39] AMPCO argues (and we agree) that demand response shutdown costs are analogous to generator startup costs, therefore, in the context of energy market participation, demand response is disadvantaged by

38 In both cases, the energy price above which the demand response should willingly activate is calculated as: Bid Price = Variable Cost + Fixed Cost ÷ Event Window. For the four-hour event this is $575 = $500/MWh + $300/MW ÷ 4 hours. For the 15-minute event this is $1,700 = $500/MWh + $300/MW ÷ 0.25 hours. Note that this example is more applicable to Dispatchable Loads than HDR resources, which can only be activated hourly once per day.

39 The IESO's Generator Cost Guarantee program reimburses generator facilities that meet eligibility criteria for incremental costs that would not have been incurred if the resource was not started by the system operator, and that are not already recovered through energy market prices.

inequivalent cost guarantees.[40] In PJM, the system operator addresses this issue by allowing demand response to submit energy bids in the day-ahead energy market that include DR shutdown cost, variable cost, and minimum downtime components.[41] Just as is the case for PJM generators with startup costs, PJM demand response resources that submit shutdown costs are eligible to be made whole for the entire cost of the offer, including shutdown costs.[42]

However, we further point out that out-of-market make-whole payments for unrecovered startup or shutdown costs (whether paid to generators or demand response) indicate a market inefficiency in which energy market prices are insufficiently high to reflect marginal system costs. Whenever possible, correcting market prices is a preferred solution to awarding make-whole payments. We discuss options to address these concerns in Section C below.

C. CHALLENGES TO FULL WHOLESALE ENERGY MARKET PARTICIPATION IN ONTARIO

In a perfectly efficient market, wholesale electricity prices provide adequate signals for demand response participants to adjust their demand patterns. When prices are low, demand for electricity increases. When prices are high, consumers reduce demand. In practice, however, existing design elements and policies in the Ontario market present barriers to full demand response participation.

1. Differences Between Wholesale Prices and Retail Rates

In most power markets, one common barrier is the lack of a direct connection between wholesale and retail prices. As discussed in Section 2 of this report, this disconnect creates a mismatch between wholesale market signals and the curtailment incentive for demand response participants and other retail customers because they are not directly exposed to wholesale prices.

While a large portion of consumers are already exposed to wholesale prices, there is a practical absence of retailers in Ontario. About 40% of customers face fixed retail prices through the Regulated Price Plan (RPP).[43] The OEB sets RPP prices based on the forecasted cost to supply electricity to RPP consumers over the next 12-month period, plus their share of the Global Adjustment (GA) charges. The OEB also determines time-of-use rates for consumers with eligible time-of-use meters as well as tiered rates for consumers with conventional meters. The OEB reviews these prices twice a year, which reflect forecasted

40 AMPCO, "Summary of Final Argument," EB-2019-0242, December 2019 at 2.

41 Submitting shutdown costs is voluntary; the default shutdown cost is zero if not submitted.
PJM, "Demand Response Shut-Down Costs in the Synchronized Reserve Market," at 2.

42 Shutdown costs are provided for in the market rules of ISO-NE, NYISO, MISO and CAISO, but not in SPP or ERCOT.
PJM, "Demand Response Shut-Down Costs in the Synchronized Reserve Market," at 3.

43 IESO, "Utilization Payment Discussion Paper," Demand Response Working Group, January 30, 2018.

market trends. However, RPP prices do not reflect wholesale market conditions in real time.[44] Even when wholesale prices spike, RPP consumers still pay the same rate and face no incentive to curtail consumption.

It is important to note that, under the current design, the basis for dispatch does not always match the uniform wholesale price. The Ontario market dispatch relies on a uniform market-clearing price independent of location-specific system conditions. In contrast to the "market schedule" (reflecting a hypothetical dispatch schedule based on the uniform market clearing price), a constrained, five-minute "dispatch schedule" is used to dispatch resources operationally, based on locational conditions at each node, which depend on transmission constraints and plant operating characteristics. A resource may not be included in the market schedule, but does get scheduled in the (transmission constrained) dispatch, and vice versa. The mismatch between uniform market prices under market schedule and prices under security-constrained dispatch can deter market participants from following dispatch instructions, potentially harming the overall reliability of the system. To mitigate this risk, CMSC payments are available to make Dispatchable Load resources whole whenever their dispatch schedule differs from their market schedule. Note, however, that there is no basis for CMSC payments to HDR resources, since they are not dispatched and settled in the IESO's energy market.

Incentive to adjust load is also absent when wholesale market prices are very low or negative. For example, when wholesale price is negative $30/MWh during surplus generation conditions that means that customers would *receive* $30 for every MWh of energy that they consume to reduce the surplus. Nevertheless, RPP consumers still have to *pay* the RPP price when increasing demand, which means they are not incentivized to adjust consumption during negative (and otherwise low) priced hours.

2. Global Adjustment Charges

The Global Adjustment charges, originally designed to support the cost recovery of private generation investment in Ontario's electricity system, have grown significantly over the years. Generation assets have been procured through either long-term contracts or regulated rates in Ontario to ensure system reliability.[45] The difference between wholesale market prices and the total cost of the regulated and contracted resources is recovered in the Global Adjustment. The Global Adjustment is also used to recover costs associated with conservation and demand management programs. Since 2008, the Global Adjustment's portion of total wholesale electricity costs recovered by the IESO has increased substantially, jumping from 10% in 2008 to nearly 80% in 2018.[46]

44 OEB, "Regulated Price Plan Manual," February 16, 2016.

45 IESO is in the process of transitioning to a market-based procurement approach, but the Ontario Energy Board recently stayed the Transitional Capacity Auction (TCA) amendments to include generators in the auction slated for December 2019.

OEB, "Decision and Order on Motion to Stay the Operations of the Amendments to the Market Rules," Issued November 25, 2019.

46 IESO, "Global Adjustment (GA)," 2019.

The recovery of Global Adjustment-related costs creates price signals that influence the consumption patterns of Ontario customers. Global Adjustment charges are recovered differently for two classes of customer. Class A customers, who also participate in the Industrial Conservation Initiative (ICI), consist of larger customers with an average peak demand over 1 MW. Allocation of their Global Adjustment charges is proportional to their share of the total (coincidental) system demand during the five highest peak-load hours of the year. In contrast, Class B customers, which are all other customers, pay a monthly Global Adjustment fee based on the MWh (or kWh) amount of electricity they consume.[47] To the extent that Class A customers can reduce their consumption during system peak loads, this Global Adjustment payment structure provides them with a strong additional incentive to reduce their load during system peaks (i.e., their "coincident" peaks). Not only do Class A customers benefit from reducing their MWh wholesale market load during high-priced peak hours, but they can additionally lower their annual Global Adjustment charges by reducing their coincident peak load during the five highest peak-load hours of the year. However, because the Global Adjustment recovers sunk (historical) costs that likely deviate substantially from both short-term and long-term incremental costs, these Global Adjustment-related incentives will not be economically efficient. Nor are the five highest load hours necessarily reflective of the periods during which wholesale energy prices spike.

In fact, the Global Adjustment charges impede full demand response participation in two ways. First, the marginal incentive for customers to curtail includes the reduction in both energy payments and Global Adjustment payments, thus distorting the wholesale market signal. For example, a customer whose activation price (value of service or cost of curtailment) is greater than the wholesale price should choose to consume electricity. However, if the combined overall savings in wholesale energy *and* Global Adjustment charges exceed this activation price, customers will choose to curtail electricity demand even if it is economically inefficient from a system-wide perspective.

Second, the recovery of Global Adjustment costs counteracts total customer savings associated with greater demand response participation. If demand response participation leads to a decrease in wholesale energy prices, this would ordinarily reduce costs to consumers. However, because most of Ontario's generating resources are contracted or regulated, a decrease in wholesale energy prices will tend to increase the costs that need to be recovered through the Global Adjustment, since differences between the wholesale prices and contracted prices and regulated costs are passed on to customers through the Global Adjustment.

As a result, Global Adjustment-related charges create significant barriers for efficient participation of demand response resources in the IESO's wholesale power market.[48]

47 IESO, "Industrial Conservation Initiative Overview," April 16, 2019.

48 If IESO continues towards implementing a market-based approach to procure capacity, the share of contracted generating resources will gradually decline. While there will be some capacity costs from the resources procured in the Capacity Auction and future auctions, Global Adjustment payments will likely decrease by a larger amount and this will provide more benefits with increased demand response participation.

D. HOW THE OPPORTUNITIES FOR DEMAND RESPONSE RESOURCES MAY EVOLVE OVER THE COMING YEARS

The increased penetration of renewable energy into Ontario's energy market will further increase the need for innovative approaches to demand response, such as increasing demand flexibility to help address the variability of renewable generation and incentivizing the charging of electric vehicles during surplus generation periods. As first steps, the IESO is reviewing its energy market design and plans to broaden one of the next demand response auction as a starting point to secure additional capacity. This new Capacity Auction will use resources from a broad range of participants to meet reliability requirements in a flexible and cost-effective manner. Anticipated medium and long-term growth of demand response will further enhance opportunities for demand response participation in the IESO markets, particularly through new technologies and business models.

1. Changes to Energy Market Design and Fundamentals

a. Energy Market Design Changes

The IESO initiated its Market Renewal Program (MRP) in 2016, with the mission of delivering a more efficient marketplace through competitive mechanisms that meet system and participant needs at lower cost. One key objective of the MRP is to create more transparent price signals, to enable market participants to respond better to system conditions on both a day-ahead and real-time basis. Under the MRP, locational marginal pricing (LMP) will ensure that the market signal for Dispatchable Loads will reflect the market's local conditions. The Day-Ahead Market creates an additional resource commitment and dispatch timeframe, which likely also better aligns with some demand response resources' capabilities.

The new Single Schedule Market will eliminate the existing two-schedule system and align market prices with operational dispatch schedules, greatly reducing the need for out-of-market payments. By accounting for congestion and losses in nodal prices, wholesale market prices in the SSM will reflect more accurately the true costs of producing electricity at any given time and location. However, it is important to note that HDR resources, modelled as aggregates of smaller customers, will continue to lack real-time energy market and dispatch schedules. HDR resources will still be subject to a set of standby and activation notifications based on pre-defined triggers (for example, when modelled locational pre-dispatch shadow price exceeds bid price), and their aggregated performance will still be assessed after-the-fact against a baseline.

The introduction of the Day-Ahead Market (DAM) will provide the IESO with additional operational certainty, which can also serve as a boon to demand response participation. Featuring financially binding prices and schedules for resources a day prior to real-time operation, the DAM encourages all resources to participate more fully and efficiently in the day-ahead timeframe. As a result, operators will be able to rely on firm resource commitments, reducing uncertainty in pre-dispatch and real-time. Demand response resources, in turn, can make informed decisions regarding when to consume or reduce energy on a day-ahead basis. Further, day-ahead market participation can act as a hedge against the higher price volatility in the real-time market caused by unanticipated changes in supply and demand.

b. Market Fundamentals Changes

Ontario has experienced high levels of renewable energy growth, with hydro, wind, and solar accounting for 37% of the province's installed generation capacity.[49] The growing share of these variable resources will diminish the system's ability to fully absorb their generation output during surplus generation conditions. Stress on the system is particularly pronounced when output from renewables coincides with high generation levels from nuclear and hydro baseload resources that have minimum generation output constraints. For example, nuclear plants cannot reduce their output easily or cost-effectively, and reducing the output of hydro plants often requires "spilling" of the valuable resource. Consequently, during these surplus baseload generation events, adding wind and solar generation places additional downward pressure on wholesale electricity prices, even causing them to turn negative and resulting in considerable curtailments and spilling of resources. In fact, negative wholesale prices occurred during 19% of the time in 2017.[50]

Because market fundamentals have been dominated by surplus energy supply in recent years, there has been little or no need to dispatch demand response. If, during low- and negative-priced hours, there were opportunities to absorb excess surplus baseline generation (SBG), there would be ample opportunities for incremental-load demand response such as electric vehicles charging,[51] but such activities currently often are not able to capitalize on these low-priced, surplus generation hours.

The energy market outlook is for a more balanced energy supply in the mid 2020s. In particular, the retirement of the Pickering nuclear station will result in a reduction of surplus generation and negative pricing. Further, the overall tightening of market conditions will increase wholesale prices, reduce Global Adjustment, and increase incentives for demand response. We would still expect only a few events with very high prices; nevertheless, this is an opportunity for more demand response during such high-priced hours.

These market design enhancements will offer more efficient opportunities for demand response. Over the long term, we anticipate growing demand response opportunities because of both the need and the growing base of demand response resources (such as distributed energy resources).

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49 IESO "Transmission-Connected Generation." This number does not include renewable facilities connected at the distribution level.

50 Kathleen Spees, "Negative Pricing in Wholesale Energy Markets," presented to Non-Emitting Resources Subcommittee, November 30, 2018. During 2017, surplus generation conditions resulted in the curtailment and spilling of approximately 10 TWh of hydro, nuclear, and wind generation. According to the IESO, negative wholesale prices occurred during 10% of the time in 2019.

51 Load increases likely have happened to some extent amongst big customers who are exposed to those prices.

2. Competition in the Capacity Auction

Using the DRA as the starting point, the IESO plans to secure the additional capacity through auctions. As proposed, this Capacity Auction will allow a broader set of market participants—such as demand response, existing (but uncontracted) generating facilities, and imports—to participate in the action, and will compensate them for their availability to provide power in the future.[52] By allowing a broader set of resources to compete, irrespective of technology type, the IESO will be able to meet Ontario's reliability requirements more flexibly and cost effectively.

In the interim, reduced demand response participation in the auction is possible. As long as existing generators and demand response resources exceed the auction demand, demand response will be exposed to more competition, which could reduce capacity prices and result in some demand response being displaced by other resource types. However, we anticipate overall growth of demand response in the medium and long term. As the system supply and demand conditions become tighter in the long term, the quantity of capacity procured in the auction will grow. This growth will also enhance opportunities for demand response activations in the energy market. The more demand response resources that exist in the market, the more will choose to participate in the energy market (even though energy market participation is relatively small portion of the total business case for most demand-response resources).

3. Advances in Technology and Business Models

Recent advances in information technology, control technology, and a proliferation of new technology have engendered new business models in the demand response and distributed energy resource (DER) space. This includes activities of technology companies that cross over between electricity consumption devices and other consumer services, such as customer smart home devices. These developments indicate a significant potential for growth in DR-related technology applications and business models. Accordingly, the IESO and stakeholders have undertaken a number of initiatives to examine the growing opportunities for demand response in a changing technology and business landscape.[53] Separately, the Energy Transformation Network of Ontario (ETNO) explores possible future structures of the distribution system, highlighting how changes in payments and market design for demand response resources can stay in alignment with these structures.[54]

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52 The first capacity auction was planned for December 2019 to secure resources for a delivery date three and a half years later. The OEB recently stayed the auction (*See* footnote 45).

53 *See* IESO, "Innovation and Sector Evolution White Paper Series," 2020.

54 Energy Transformation Network of Ontario (ETNO), "ETNO Report on Structural Options for Ontario's Electricity System in a High-DER Future," 2019.

Ontario has experienced a rapid expansion of DERs, wind and solar generation, and electric vehicles (EV).[55] According to the ETNO report, more than 4,000 megawatts (MW) of DERs have been contracted or installed over the past 10 years. Similarly, the IESO expects that electric vehicle sales will grow steadily in the next decade, estimating that the number of electric vehicles on Ontario roads will reach about 1 million around 2040, with an annual charging demand of about 3.4 TWh.[56]

As of the third quarter of 2019, 41,300 zero-emission vehicles are operating in the province.[57] While there may be some short-term fluctuations in the annual deployment numbers, we expect the rate of deployment of these technologies to increase as the cost of the technologies continues to decline.

Higher penetration of DERs will bring more uncertainty to Ontario's wholesale market, potentially creating operational challenges to the energy system. However, output from intermittent resources can decrease and increase quickly (for example, at solar facilities due to variable cloud cover). As a result, Ontario system operators must rely on flexible resources to respond promptly to changing system conditions, or risk degrades in system reliability.

Technological changes and innovations may necessitate changes in the organizational structure of Ontario's energy system in the future. To integrate and maximize the demand response benefits of new distributed energy resources into the energy system efficiently, alongside large-scale generation resources, existing roles and responsibilities of different entities within the market may need to evolve, including the functions of LDCs, demand response aggregators, and potential future distribution system operators. Given the complex organization of the market, the variations of the entities, and the policy uncertainty, a number of re-organizations may occur.

Given this potential for major changes to industry structures, any modified approaches to enabling energy market participation that are developed through the present stakeholder initiative will need to align with the industry models outlined in the ETNO studies, to the largest extent possible. This means that a variety of business model arrangements should be contemplated and accommodated for demand response participation in the energy market, including (but not limited to):

- **Large customers respond directly to wholesale market signals.** Given the size of their demand, these customers can directly respond to wholesale market conditions, and may bypass intermediaries such as demand response aggregators.
- **Large customers work with a retail provider or an energy service company to respond to wholesale price signals.** Demand response, energy, retail services are treated as a bundled line of services offered by one company.

[55] DERs are electricity-generating resources or controllable loads that are connected to local distribution system. They include rooftop solar, combined heat and power plants, electricity storage, small natural-gas-fired generators, controllable loads, such as HVAC systems and electric water heaters, among others.

[56] IESO, "Enhancing Long Term Planning Processes and Products and Preliminary 2019 Long-Term Demand Forecast," January 31, 2019.

[57] Electric Mobility Canada, "Electronic Vehicle Sales in Canada – Q3 2019," November 2019.

- **Demand response aggregators engage in wholesale market on behalf of individual customers or aggregated classes of customers.** In this model, non-utility third parties operate an aggregate of demand response resources. Examples might include electric vehicle demand response service aggregators, HVAC systems aggregators, and water heaters aggregators. This service is separate and distinct from retail and/or billing service provided to the same customer by LDC or retailer.
- **Multiple different demand response aggregators may serve the same individual customer.** These services generally would not be expected to be bundled or associated with retail service or billings as delivered by the LDC or retail provider. Separate companies aggregate different types of demand response such as electric vehicles, thermostats, and distributed storage. The same customer may engage in wholesale market via multiple avenues through different companies that control their electric vehicle, thermostat (for electric and gas use), smart devices (some electric, some not), *etc.*
- **Local distribution companies (LDCs) assume the role of demand response aggregators directly or in partnership with demand response aggregators.** In this model, LDCs are responsible for providing demand response service. Today, LDCs earn their revenues from electricity delivery, but are not responsible for the difference between wholesale and retail price. In this scenario, in addition to owning and operating distribution systems, LDCs also serve as demand response providers, delivering energy reduction (or increase) from their customers in response to the IESO's dispatch instructions.
- **An entity like an independent distribution system operator (DSO) coordinates demand response activations of individual DERs or aggregators.** Under this model, analogous to the role of the IESO in the bulk power market, a DSO is responsible for conducting physical dispatch of the distribution system. The DSO dispatches demand response as an energy resource. In one extreme, the DSO can be one central clearinghouse for all of the LDCs and demand response providers. In another extreme, different DSOs, representing different LDCs, coordinate with one another. In another version, DSO fully assumes the functions and responsibilities of LDCs in what is termed a "fully-integrated network orchestrator."[58]

With the exception of the DSO option, all of these models are currently possible. It is beyond the scope of this paper to speculate and analyze the different possible scenarios in which certain models may be better suited for Ontario's and their implications on the demand response market. In fact, it is impossible to predict the exact scenario, or its variations and combinations that will take place in the future. However, it is critical that market design changes ensure that incentives are economically efficient, given the potential for the development of large quantities of demand response activity (and thus the magnified impact of any inefficient incentives that could be introduced). The market design changes must also avoid inducing institutional and technological lock-ins that would introduce more constraints and reduce the flexibility to evolve with market conditions and technological progress, thereby ensuring that the best technologies and business models will thrive.

[58] Energy Transformation Network of Ontario, "Structural Options for Ontario's Electricity System in a High-DER Future," June 2019 at 17.

III. How are Demand Response Activations Compensated in Other Jurisdictions' Energy Markets?

As summarized in **Table 2**, other jurisdictions, such as Alberta, PJM and ISO-NE, Texas, Singapore, and Australia, handle demand response participation in several different ways. These jurisdictions and their energy-market activation compensation methods are discussed in greater length in the following sections.

TABLE 2: SUMMARY OF ENERGY MARKET PARTICIPATION IN SELECT OTHER JURISDICTION

Jurisdiction	Description of Energy Market Participation Method	Participation Level
Alberta (Wholesale Price Exposure, no payments)	• Alberta's energy-only market enables explicit demand bids in the energy market, but offers no compensation or incentive for loads to participate in this way. Thus, there is little or no such dispatchable demand response visible to the AESO • Alberta does have a number of industrial loads that respond to real-time price signals, but they do not contribute to price formation	• As of 2011, Alberta demand response served roughly 1.5% of peak load
U.S. Jurisdictions FERC Order 745 (Full LMP Approach)	• In FERC-regulated U.S. wholesale power markets, demand response is compensated at full LMP under the net benefits test for participation in the day-ahead and real-time energy markets	• U.S. markets with demand response programs have an average of 5.6% peak demand from demand response (28,000 MW)
Texas (Demand-side, LMP minus G Approach)	• Demand response can participate in the day-ahead and real-time energy markets through voluntary curtailment. • Alternatively, demand response can participate on the demand side, receiving a marginal incentive that is equivalent to LMP minus G	• Texas has 4.3% of peak demand from demand response and 3,000 MW
Singapore (Consumer Surplus Sharing Approach)	• Demand response submits a self-reported baseline, curtailment and price options, and ramp rates in a bid • When dispatched, demand response aggregators are paid 1/3 of consumer surplus • To date, participation has been limited (7.2 MW of registered capacity) owing to high penalties and low energy prices	• Demand response has only been dispatched in two instances since implementation in 2016

Jurisdiction	Description of Energy Market Participation Method	Participation Level
Australia (Purchase and Sellback Approach)	• The AEMC establishes a customer baseline, and demand response is compensated based on the deviation between customer baseline and actual consumption at the full wholesale price (compensation balances out to LMP minus G compensation)	• The NEM estimates that 220 MW of demand response capacity is available if spot prices exceed $1000/MWh, with over 1000 MW available at the $13,800/MWh cap

Notes and sources:

— Alberta stopped publishing demand response data after 2011. Brown, *et al.*, "International Review of Demand Response Mechanisms," 2015 at 4.

— Energy Market Authority, "Implementing Demand Response in the National Electricity Market of Singapore," *See* Tables 8A and 8B, 2013 at 4.

— AESO has identified six price response loads where a strong correlation between market price and energy is observed. Johannes Pfeifenberger and Attila Hajos, "Demand Response Review," 2011 at 19.

— Federal Energy Regulatory Commission, "2018 Assessment of Demand Response and Advanced Metering," *see* 2017 values in Table 3-3, 2018 at 15.

— Australian National Energy Market, "State of the Energy Market 2015," 2016 at 36.

A. ALBERTA APPROACH WITH NO ENERGY MARKET PAYMENTS FOR ACTIVATIONS

Alberta's energy-only market allows load resources to submit demand bids into the energy market, but the market design provides few incentives for customers to do so. Participants can choose to submit bids into the market and receive dispatch instructions from the system operator, but most price-responsive loads simply 'follow' the wholesale market prices without submitting bids that would subject them to various obligations and requirements. However, once participating in the energy market, demand response providers are subject to the same administrative and regulatory rules as generators. Demand response resources must respond to dispatch in real time, having to ramp up or ramp down as instructed, an activity that requires non-trivial technical capability. Demand response receives no compensation beyond their savings from not consuming energy. Thus, instead of participating in the energy market through bids that make them subject to these obligations, loads simply tend to respond to the posted wholesale prices and adjust their consumption on their own terms, instead of being dispatched by the AESO.

Because of this design, there has not been bid-based, dispatchable demand response participation in Alberta's energy market. However, Alberta has a large number of industrial loads that are directly exposed to wholesale prices. As the AESO has documented, some of them do respond to real-time price signals by choosing not to consume when wholesale prices exceed certain thresholds, with their marginal incentive equal to the savings from not consuming a high-priced MWs.[59]

Unfortunately, the manner in which loads participate in the Alberta energy market offers little visibility and no direct dispatch control to the system operator; this diminishes the benefits associated with demand response. While load resources privately optimize their consumption behavior in accordance with their willingness to pay and their technical capabilities, they are not required to offer information related to quantity, type, location, and availability to the system operator. It is more challenging for the system operator for the purpose of both real-time dispatch and future planning to account for this demand response resource. This lack of visibility and control reduces the benefits of demand response, such as enhanced reliability, deferral of investments in generating capacity or in transmission and distribution facilities.

TAKEAWAYS FOR ONTARIO

- **Without payments or other incentives for direct energy market participation, few or no demand response providers voluntarily choose to participate (including taking on associated response requirements)**
- **Even without energy market payments, large industrial loads that are exposed to wholesale prices can and do respond to real-time price signals, but the system operator does not have full visibility into their participation in the energy market and cannot dispatch these loads**
- **Lack of visibility of demand response resources results in reduced benefits to the system**

B. U.S. MARKET PAYMENT STRUCTURES BEFORE AND AFTER FERC ORDER 745

Prior to the FERC Order 745, system operators in most FERC-regulated U.S. jurisdictions have compensated demand response for energy market participation at the wholesale price less the

[59] AESO has identified six price response loads where a strong correlation between market price and energy is observed. Johannes Pfeifenberger and Attila Hajos, "Demand Response Review," Presented to AESO, March 2011 at 19.

generation component of the retail rate ("Wholesale Price minus G"). The U.S. system operators experimented with a number of approaches to demand response participation in wholesale markets, before converging on a general consensus that LMP minus G would provide an efficient marginal incentive when (and only when) wholesale prices exceeded the curtailment incentives already available through retail rates.

In 2010, under policy initiative to enable and integrate demand response further into the wholesale markets, the FERC proposed a rule awarding full LMP payment to demand response participants at all hours. The FERC argued that "unjust and unreasonable" compensation by U.S. RTOs and ISOs would depress demand response participation and that increasing compensation to full LMP payments would enable greater levels of demand response.[60]

The FERC argued that full LMP payments are the efficient compensation methodology under the assumption that the marginal value provided by demand response is equivalent to the marginal value provided by a traditional generator, and therefore compensation should be "comparable to the treatment of generation resources."[61] The FERC also argued that demand response participants have more barriers to entry than traditional generators and that markets that pay less than the full LMP to demand response resources do not adequately compensate demand response to remove those barriers. The Notice of Proposed Rulemaking leading up to the final order offered the example that demand response participants are required to invest in demand-response-enabling technology such as metering and usage monitoring technology and consequently incur costs that typical generators do not.[62] The Commission suggested remedying this particular barrier to entry, at least in part, by increasing energy payments to the full LMP.[63]

In the final Order 745, the FERC added a provision that demand response would only be compensated under certain system conditions, subject to a "customer net benefits test."[64] All RTOs must conduct an analysis each month to estimate a threshold price level (the "Net Benefit Test Price") above which customer benefits from price reduction (calculated as the achieved price reduction multiplied by the total MW of market demand) would exceed the payments to the demand response resource (calculated as full LMP times demand response curtailed MW). The net benefits test is illustrated in **Figure 4** below. Customer benefits are shown in red and payments to the demand response resource in green. Net benefits are achieved only if the consumer savings (light blue box) exceed the demand response

[60] FERC, "Demand Response Participation in Organized Wholesale Markets," Docket Nos. RM10-17-00 and EL09-68-000, March 18, 2010 at 13.

[61] *Ibid*.

[62] *Ibid.,* 16.

[63] *Ibid.,* 17.

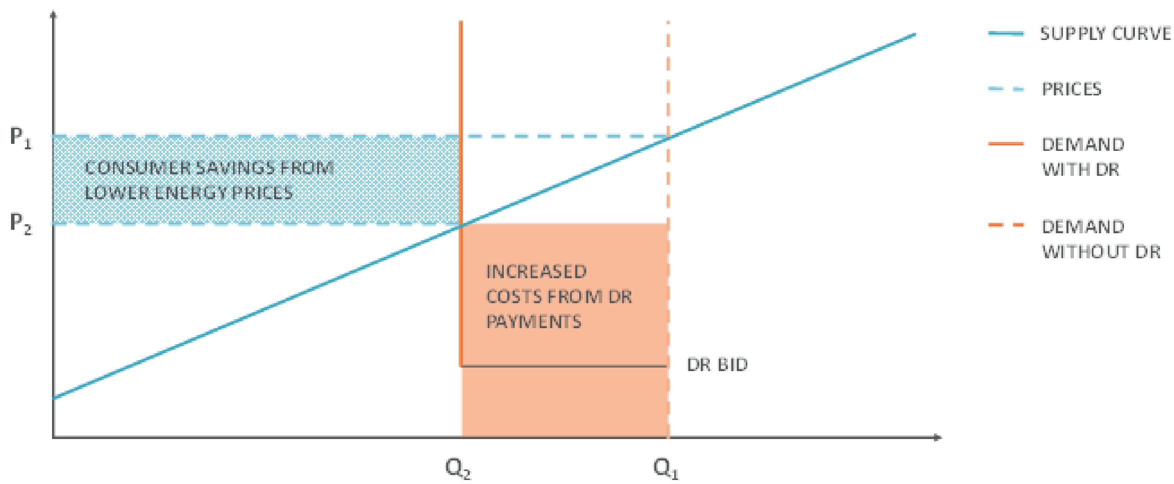
[64] A detailed discussion of the net benefits test is provided in the Appendix.

FERC, "Demand Response Compensation in Organized Wholesale Energy Markets," Docket No. RM10-17-000; Order No. 745, March 15, 2011.

payments (red box). In the hours where savings exceed costs, the demand response providers will qualify for full LMP payment.

Following implementation of Order 745, PJM demand response activity grew briefly but declined in the following years. Historically, economic demand in PJM averaged 4 GWh per month of demand response participation in the energy market, totaling 166 GWh since November 2008.[65] During the seven month period after PJM adopted full LMP payments (April through October 2012), economic demand response was dispatched for over 133 GWh at an average of 19 GWh per month, a 400% increase across the program's monthly average since late 2008.[66] After the Order, PJM demand response also received 50% more revenue for economic dispatch on average.[67] However, economic demand response activity has declined back to pre-Order 745 levels, as shown in **Figure 5** below.

FIGURE 4: NET BENEFITS TEST BASED ON FERC ORDER 745



Notes:

— Q1 is the status quo system demand in a given hour.

— Q2 is the quantity of system demand after demand response curtails consumption.

— P1 and P2 are the corresponding prices. The payments owed to demand response (red shaded section) is the [curtailment quantity (Q1-Q2) x the price after curtailment (P2)].

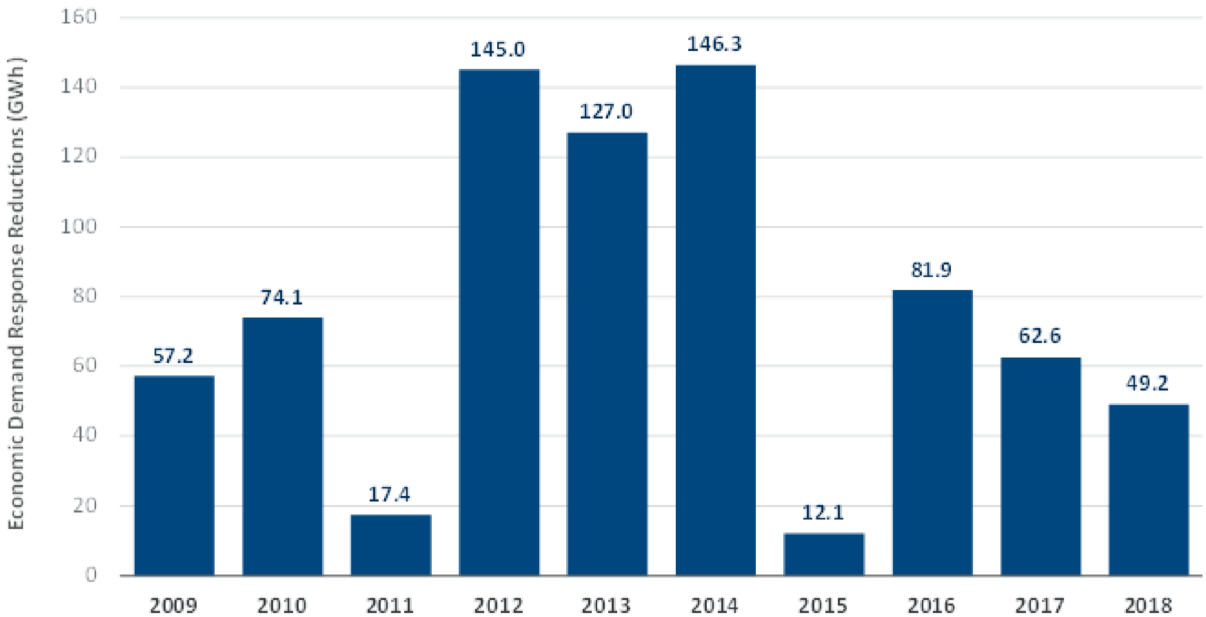
— The consumer savings (section shaded in light blue) shows the benefit from price reduction resulting from paying the lower price for energy [(P1-P2) x Q2]. To qualify for compensation under the net benefits test, the value to customers (teal box) must exceed the demand response payments shown (orange box).

65 PJM, "2012 Economic Demand Response Performance Report," March 25, 2013 at 2.

66 Before 2008 PJM had extensive economic demand response participation under their Economic Load-Response subsidy payment program which expired on December 21, 2007. In November 2008, PJM amended demand response payments from (LMP minus G minus T) to (LMP minus G). "2009 State of the Market Report for PJM," Prepared by Monitoring Analytics, 2010 at 105.

67 PJM Economic Demand Response made $8.7 million in revenue for 133,466 MW of reductions between April and October of 2012 (averaging $65.19/MWh). Demand Response participants made $7.1 million of revenue from November 2008 through March 2012 for 166,276 MWh of reductions (averaging $42.70/MWh). PJM, "2012 Economic Demand Response Performance Report," March 25, 2013 at 2.

FIGURE 5: PJM DEMAND RESPONSE REDUCTIONS IN GWH (2009–2018)



Sources: PJM, "2013 State of the Market Report," (2013) at 201. PJM, "2018 State of the Market Report," (2018) at 310.

Demand response in PJM is able to offer as a capacity, energy, or ancillary services resource. Demand response that participates in the energy market submits a "strike price," or the price at which a provider would be willing to curtail an MWh. When LMPs exceed the strike price, demand response will be called upon to offer curtailment as an energy resource. By offering as both a capacity and energy resource, demand response is guaranteed the minimum of their strike price and the zonal LMP. In 2018, 98.8% of nominated demand response MW were offered as capacity and energy resources, with only 1.2% of demand response capacity offered as capacity only.[68] Despite high enrollment in economic demand response programs, most revenue comes from capacity market payments. Total revenue by demand response participants was $598.6 million in 2018, where 98.1% of all demand response revenues came from capacity market payments. The demand response shutdown cost per nominated MW in the PJM capacity market averaged $114.28 in the 2017/2018 delivery year.[69] Ultimately, since demand response in PJM participates receives the bulk of revenue from capacity markets, the PJM transition to FERC 745 LMP payments did not fundamentally change how demand response participates in the PJM system. Before and after FERC 745, the bulk of the PJM demand response offers as economic and capacity resources and makes the majority of revenue from capacity market payments.[70]

68 "2018 State of the Market Report for PJM," Prepared by Monitoring Analytics, 2019 at 325.

69 *Ibid.*, 324.

70 From 2010 to 2018, 95% of revenue for PJM demand response comes from capacity market payments. London Economics International LLC, "Demand Response Programs in Selected US Markets," 2019 at 19.

In response to FERC Order 745, ISO New England (ISO-NE) introduced the Price-Responsive Demand (PRD) in June 2018.[71] The PRD framework enables demand response to operate as a generator: demand response providers submit bids to the day-ahead and real-time energy markets, and respond when dispatched by the system operator. Enrollment ranged between 220–378 MW during the transitional period (between 2013 and 2017). Only 14 resources received more than one hour of demand reduction obligation in the day-ahead energy market. The total demand response reductions averaged 6 MW and never exceeded 19 MW in any hour in the program's lifespan.[72] In the 2018 PRD program, the maximum demand resource dispatch was 31.2 MW, and averaged 7.7 MW from June–December 2018.[73]

Since 2013, there has been a large reduction in overall demand response participation in New England capacity markets, as shown in **Figure 6** below. Early in the decade, New England had around 1,700 MW of demand response capacity, relative to around 750 MW today. New England attributes this initial 2013 reduction to retirement of assets by EnerNOC, the lead demand response provider to New England forward capacity auctions in 2012.[74] **Figure 6** also highlights the trend in ISO-NE energy market enrollment after the FERC Order 745. Demand response enrollment in the Real-Time Price-Response (RTPR) and Day-Ahead Load-Response (DALR) Programs were roughly equivalent to enrollment in the first year of the TPRD program in 2012. More surprisingly, the RTPR and DALR programs also paid providers LMP for curtailment. Since 2012, enrollment in the PRD program has not increased, continuing at levels of 200-300 MW.

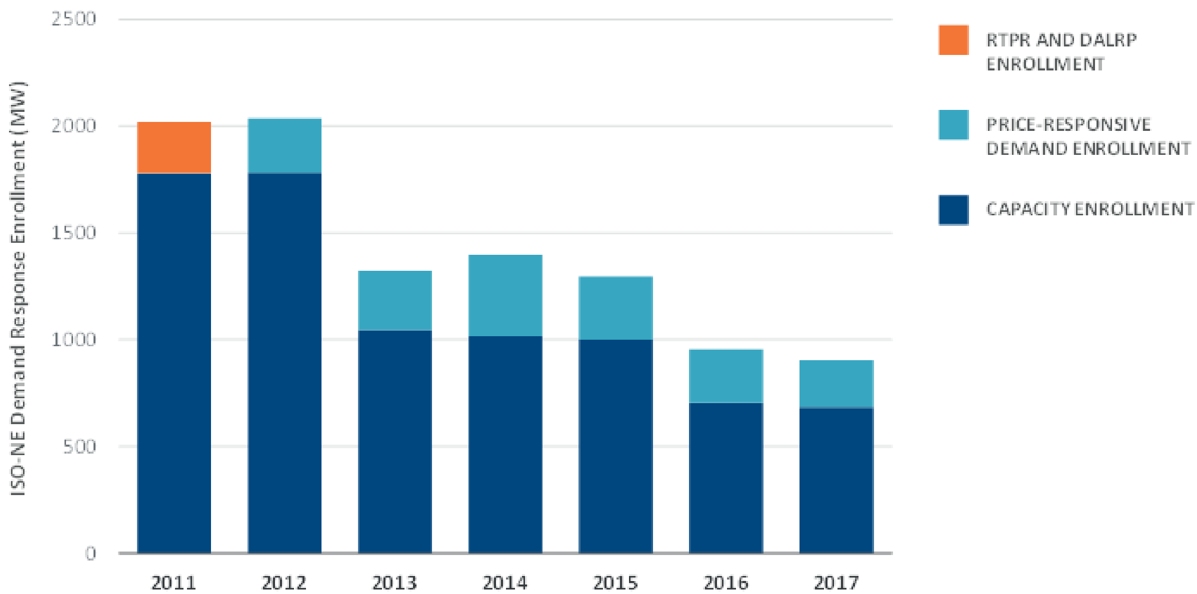
[71] ISO-NE had previously operated Real-Time Price-Response (RTPR) and Day-Ahead Load-Response (DALR) Programs. These programs treated loads as distinct from generation whereas the PRD program schedules and dispatches demand response under the same market rules as generators.

[72] ISO-NE, "Demand Resources Working Group 1/1/2012," 2013 at 8; ISO-NE, "Demand Resources Working Group 1/30/2013," January 30, 2013 at 8; ISO-NE, "Demand Resources Working Group 12/1/2013," 2013 at 5 and 6; ISO-NE, "Demand Resources Working Group 2/1/2015," 2015 at 6 and 7; ISO-NE, "Demand Resources Working Group 1/1/2016," 2016 at 5 and 6; ISO-NE, "Demand Resources Working Group 12/1/2016," 2016 at 5, and ISO-NE, "Demand Resources Working Group 1/1/2018," 2018 at 5.

[73] ISO New England Inc., 2018 Annual Markets Report, Internal Market Monitor, May 23, 2019. Demand response participants under the PRD program are able to provide reserves. In 2018, 140 MW of demand response offered offline reserve capacity. However, most demand resources continue to participate predominantly as capacity resources providing high-priced energy and reserves on the real-time energy market.

[74] ISO-NE, "2012 Annual Markets Report" May 15, 2013 at 36; ISO-NE, "2013 Annual Markets Report" May 6, 2014 at 104.

FIGURE 6: ISO-NE DEMAND RESPONSE PROGRAM ENROLLMENT (2011–2017)



Notes and sources: Passive Demand Resource assets are not included in capacity enrollment as they are not dispatchable.

— ISO-NE, "Introduction, Demand Resources Working Group 1/1/2012" at 6 and 8, (2012).

— ISO-NE, "Introduction, Demand Resources Working Group 1/1/2013" at 7 and 8 (2013).

— ISO-NE, "Introduction, Demand Resources Working Group 12/1/2013" at 5 and 6 (2013).

— ISO-NE, "Introduction, Demand Resources Working Group 2/4/2015" at 6 and 7 (2015).

— ISO-NE, "Introduction, Demand Resources Working Group 1/1/2016" at 5 and 6 (2016).

— ISO-NE, "Introduction, Demand Resources Working Group 12/1/2016" at 5 and 6 (2016).

— ISO-NE, "Introduction, Demand Resources Working Group 1/1/2018" at 5 and 6 (2018).

TAKEAWAYS FOR ONTARIO

- Though FERC and demand response providers favored a "full LMP" energy market payments model, the RTOs, market monitors, and others (including ourselves) argued in favor of maintaining the prior "LMP minus G" approach to offer the most economically efficient curtailment incentives
- Regions with capacity markets have attracted large quantities of demand response, which can translate to significant participation in energy markets as well (especially if resource visibility and dispatchability is a requirement to earn capacity payments)
- Efficient energy market participation can be measured based on large quantities of visible and dispatchable supply-side offers, which can participate in energy market participation and help meet reliability needs. Activations during scarcity events are likely to be infrequent, at least as long as energy prices remain low and below many customers' value of lost load the majority of the time
- Placing strict energy market participation requirements on demand response can introduce barriers and costs that exclude some resources. Flexibility in the nature of requirements, especially for infrequently dispatched resources, can enable more types of demand response
- Even demand resources that are notionally dispatched on an "emergency" or "reliability" basis can help contribute to energy price formation, such as through PJM's strike price approach. However, this type of curtailment is less visible to the system operator

C. TEXAS DEMAND-SIDE PARTICIPATION

The Energy Reliability Council of Texas (ERCOT) is unique among U.S. jurisdictions. It does not operate with a resource adequacy requirement and therefore does not utilize a capacity market of any sorts. Instead, ERCOT relies on high wholesale energy prices to encourage generation during shortage events.[75] Additionally, because ERCOT is not synchronized with the rest of the United States, ERCOT is not subject to oversight by the FERC.[76]

ERCOT allows demand response to operate in day-ahead and real-time ancillary service and energy markets. Demand response may participate in the energy market in one of two ways: demand response that observes wholesale prices can respond to high prices by voluntarily curtailing consumption (similar to current practices in Alberta and Ontario) and will be compensated only in energy savings from that reduction. Alternatively, demand response may actively participate in energy markets as a demand-side resource in the Controllable Load Resources (CLR) program. For a load serving entity in ERCOT's competitive retail market, the marginal incentive of facilitating their customers' demand response to curtail load is the wholesale price the Load Serving Entity (LSE) pays minus the generation component that the LSE would receive from its customer. While the incentive is similar to LMP minus G, which was available in some U.S. jurisdictions before FERC Order 745, it is important to note this incentive to curtail is available in the form of savings instead of additional payments. ERCOT's CLR demand response program, as designed, does not provide opportunities for aggregators to offer demand response as a separate service from retail supply.

Voluntary demand response—load reductions in response to observed wholesale market prices—happen quite frequently in ERCOT due to high prices during shortage events. For customers who consume energy at the wholesale price, high ERCOT market prices present a strong incentive to curtail load during such shortages. In 2018, ERCOT estimated that about 1,700 MW of load were actively reducing consumption during the peak intervals in 2018 (an increase of 200 MW from the estimated 1,500 MW in 2017).[77]

75 ERCOT wholesale price cap is $9,000/MWh.

ERCOT, "2018 Annual Report of Demand Response in the ERCOT Region," March 2019 at 22.

76 Toby Brown, *et al.*, "International Review of Demand Response Mechanisms," Prepared for Australian Energy Market Commission, October 2015 at 39.

77 ERCOT, "2018 Annual Report of Demand Response in the ERCOT Region" March 2019 at 7.

It has been noted that transmission charges in ERCOT may induce significant market distortions during system peak periods. ERCOT allocates transmission costs based on transmission customer loads during the four coincident-peak (4CP) fifteen-minute periods of the peak months between June and September.[78] In anticipation of the forecasted four peak periods, customers voluntarily reduce their demand to avoid transmission charges—but distorting wholesale energy market prices as a result. This was apparent on peak load days over the last three years when demand response made significant load reductions during system peaks even when wholesale prices were low.[79]

ERCOT attempted to remedy this problem by requiring qualifying CLR resources to respond to 5-minute dispatch instructions by specifying the wholesale price at which they no longer wish to consume (a "strike price"). However, there are currently no loads qualified to participate in real time dispatch.[80]

TAKEAWAYS FOR ONTARIO

- **High wholesale market prices encourage demand response participation. Demand response providers that participate on the demand-side receive an incentive equivalent to LMP minus G**
- **Coincident peak load charges for recovery of transmission (and other) costs distort demand response curtailment incentives. Demand response participants are incentivized to reduce peak demand and lower their charges for system-wide fixed-cost recovery (without reducing system-wide fixed costs) in addition to receiving energy market savings.**

D. SINGAPORE CUSTOMER BENEFITS TEST APPROACH

Singapore's demand response program, implemented in 2016, features two distinct design elements: (1) a self-nominated consumption baseline, and (2) a consumer surplus sharing scheme.

78 "2018 State of the Market Report for the ECROT Electricity Markets," Potomac Economics, June 2019.

79 In 2016, prices during the 4CP were $25-40/MWh, in 2017 prices during the 4CP were less than $100/MWh and in 2018 prices during the 4CP were less than $40/MWh. ERCOT, "2018 Annual Report of Demand Response in the ERCOT Region," March 2019 at 91.

80 *Ibid*., 91.

To participate, demand response providers can submit their own baseline consumption levels, along with price-quantity curtailment bids, and ramp rates. The self-nominated baseline is meant to overcome gaming problems related to historical baselines. Because demand response participants' compensation is proportional to the difference between the baseline and actual consumption, participants could artificially inflate their baseline by shifting consumption to hours of historically high consumption, even if overall energy use remains unchanged.

To incentivize the accurate reporting of the baseline, demand response providers face a penalty if realized load deviates from the baseline, regardless of whether the market clears above or below the strike price.[81] In practice, this approach has discouraged participation in the demand response program with a registered capacity of only 7.2 MW as of this year, as the potential cost of penalties has exceeded the attractiveness of participation (particularly given low prevailing energy prices and the associated low potential gains from full participation).[82,83]

As compensation for dispatch during high-priced hours, demand response participants receive a payment equal to a third of the total consumer surplus. The consumer surplus calculation conceptually is the same as the FERC 745 net benefits test (see Section III.B of this report), but rather than a binary test with compensation at full LMP or no payment when net benefit is not achieved, Singapore pays demand response at one-third of total benefits. Compensation is capped at S $4,500/MWh (CAD $4,377/MWh). This ensures that the majority of benefits derived from demand response participation are returned to the customer, guaranteeing that payments to the demand response participant provide a net benefit to customers overall (in the form of reduced wholesale prices).

81 For more information, please see Tables 8A and 8B of the Final Determination. Available at

Energy Market Authority, "Implementing Demand Response in the National Electricity Market of Singapore," October 28, 2013.

82 Brown, *et al.,* "International Review of Demand Response Mechanisms in Wholesale Markets," Prepared for the Australian Energy market Commission, June 2019 at 12

83 This self-nominated baseline is not immune to gaming either. For example, in anticipation of high prices, a provider could submit an artificially high baseline. If the price forecast proves incorrect, the demand response provider could choose to increase its load (*e.g.*, by uneconomically starting an industrial process) to remain compliant.

TAKEAWAYS FOR ONTARIO

- **Demand response participants could be compensated as a share in the consumer surplus, such as receiving one third of the total benefits (up to CAD $ 4,377/MWh)**
- **High penalties can discourage demand response program participation (especially if energy prices are low)**
- **Use of baseline consumption levels can enable energy participation on the supply side**

E. AUSTRALIA'S TRANSITION TOWARD A PURCHASE-SELLBACK MODEL

Australia's National Energy Market (NEM) is an energy-only market that does not incorporate a capacity mechanism. Wholesale demand response is compensated through wholesale savings (when demand response reacts to wholesale prices).[84] In a November 2018 draft rule, the Australian Energy Market Commission (AEMC) established the need for increased demand response participation, visibility, and reliability. To address this need, the Australian regulator has proposed transitioning its demand response program to a "purchase-and-sellback" model.[85] The proposed rule change will open up the demand response market to new participation through demand response aggregators and electricity retailers. Under the trial program, ten pilot projects are receiving funding from the Australian Renewable Energy Agency for deployment in the summer of 2020.

The purchase and sellback model features involves four parties: the system operator, the retailer, the customer, and the demand response aggregator.[86] The system operator determines a baseline level of consumption for the customer. Regardless of actual consumption, the retailer is deemed to purchase

84 Ben Madafiglio, Anna Bruce and Iain MacGill, "Impact of Demand Response in the Australian National Electricity Market with High Renewable Energy Penetration," Presented at the Asia-Pacific Research Conference, 2017.

85 Extensive stakeholder engagement is ongoing. Descriptions of the model are based on the Draft Rule Determination published on July 18, 2018. Available at

Australian Energy Market Commission, "Draft Rule Determination," July 18, 2019.

86 In the Ontario context, the retailer's role would be roughly equivalent to that of the Local Distribution Company, the customer to that of the contributor, and the aggregator to that of the demand response provider.

electricity on the wholesale market at the baseline level of consumption. The retailer receives a bill from the system operator in two separate amounts calculated at the wholesale price, which are: (1) the customer's actual consumption; and (2) the difference between the customer's actual consumption and its baseline consumption.

The retailer passes on to its customers the first portion of the bill, based on the customer's actual consumption, consistent with current retail market operations. When baseline consumption is equal to actual consumption, the retailer bills customers exactly as per usual, and the second portion of the bill is zero. The demand response provider does not receive any payments under No. 2 above.

In the case where demand response is dispatched (causing baseline consumption to exceed actual consumption), the system operator bills the retailer in two parts. As before, the retailer passes the bill for actual consumption to the customer, but this time, the second component of the bill is not recovered from the customer, but from the demand response provider for the curtailed amount at a reimbursement rate, which is designed to be close to the retail rate.[87] The demand response provider is compensated by the system operator for the curtailed MW (difference between actual and baseline consumption) at the full wholesale price. The demand-response provider then also shares a portion of its benefits (the curtailed MW compensated at the high wholesale price less the cost of "buying back" the curtailed MW from the retail provider at the reimbursement rate) with the customer at a predetermined rate.[88]

In essence, this mechanism is equivalent to the demand response providers having to purchase energy from the retailer at the (lower) retail rate, before being able to sell it back into the market at the (higher) wholesale price. When curtailment occurs, the demand response receives compensation that is equal to the wholesale price minus the costs to make the retailer whole. While the net incentive available to demand response is the same as under the *LMP minus G* model, this payment model differs in the payment flows through which demand response is compensated.

Figure 7 provides an example. Without demand response activation, the retail customer consumes 15 MW at the (energy component of the) retail rate of $35/MWh, while the retailer would purchase 15 MW at the high $500/MWh wholesale energy market price (as shown on the left side of the figure). When demand response is activated (as shown on the right side of the figure), the retailer will continue to pay the system operator for the 15 MW baseline energy quantity, which consists of two different amounts: the actual consumption (10 MW) and the demand response curtailment quantity (5 MW). This bill continues to be a total of $7500. For the curtailed 5 MW amount, the demand response provider receives a payment of $2500 from the system operator. The customer pays $350 to the retailer for their actual 10 MW energy consumption, and receives a credit from the demand response provider based on their agreed-upon terms for allowing the curtailment. Finally, the demand response provider reimburses

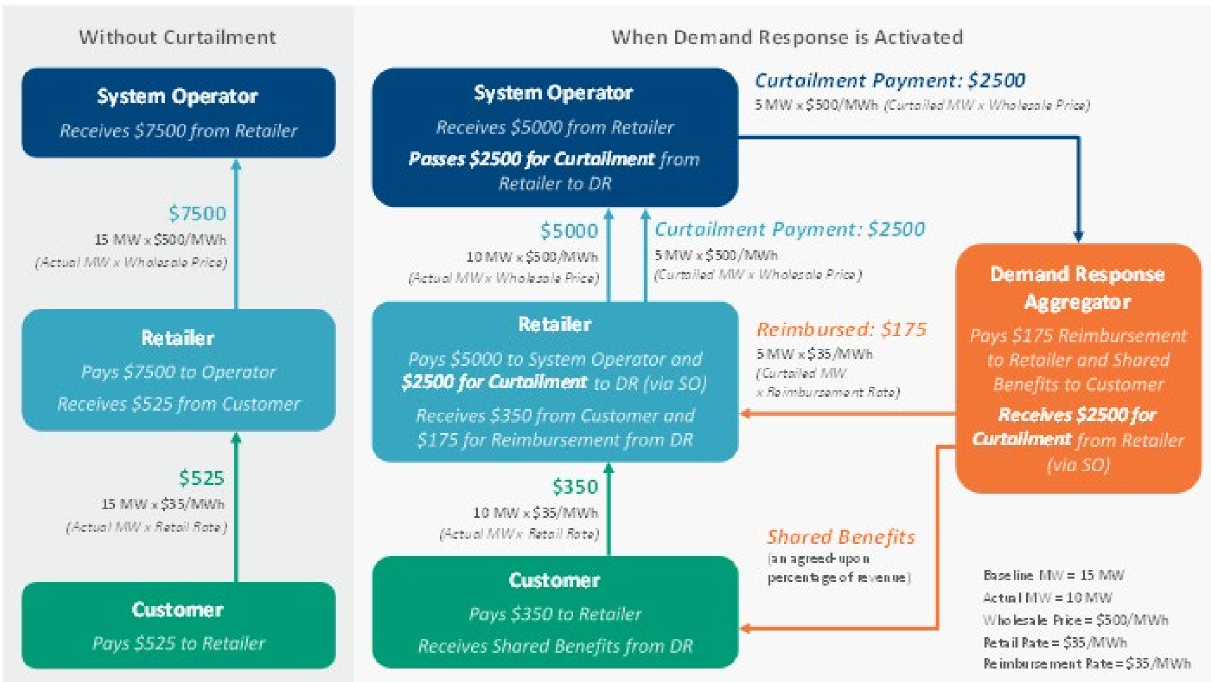
87 The Australian Energy Regulator determines the Demand Response reimbursement rate on a quarterly basis using the average wholesale price across the previous 12 months. The reimbursement rate reflects the average retail rate for the customer providing the demand response.

88 The benefits sharing mechanism between Demand Response and customer is a predetermined reimbursement rate, calculated by the Australian Energy Regulator on a quarterly basis and based on the average wholesale price across the previous 12 months.

Australian Energy Market Commission, "Draft Rule Determination," July 18, 2019 at 63.

the retailer for "purchasing" 5 MW at the predetermined reimbursement rate, which will generally be the $35/MWh energy component of the retail rate. The net effects are (1) the retailer is indifferent as it continues to get paid for 15 MW at the $35/MWh retail rate (receiving payment for 10MW from the customers and 5 MW from the demand response provider); (2) the demand response provider "buys back" 5MW from the retailer but receives the $500/MWh wholesale market price from the system operator; and (3) the customer saves $35/MWh on the curtailed 5 MW of retail load plus a DR-participation payment from the demand-response provider.

FIGURE 7: AUSTRALIAN APPROACH: PAYMENT FLOWS UNDER PURCHASE-AND-SELLBACK APPROACH



Notes: This chart simplifies the make-whole "reimbursement" payment flows. In the proposed approach, the system operator settles the reimbursement between the retailer and Demand Response Aggregator.

TAKEAWAYS FOR ONTARIO

- **In the purchase-and-sellback model, demand response providers have an actual supply product ("purchased" from retailers) to offer into the market, for which they receive the wholesale market price, resulting in an efficient signal to adjust consumption behavior**
- **Demand response participant's ability to set wholesale prices allows for economically efficient integration. The proposed design also takes into account the existing relationships between different entities within the Australian market. Allowing retailers to continue to bill customers based on actual consumption minimizes changes to the billing systems and associated implementation costs**
- **Demand response providers settle the benefits and costs associated with load deviation from the baseline. Payments from retailers to the system operator (based on baseline consumption) and from demand response providers to retailers (based on curtailed consumption) keep retailers indifferent.**

IV. What are the Demand Response Compensation Options for Ontario?

Currently, demand response participants in the Ontario energy market do not receive energy market payments when activated, though in some cases compensation exists in other forms (as in the case of CMSC payments for Dispatchable Loads). Possible solutions consist of various forms of payments for curtailing consumption during periods of high prices. This includes paying demand response participants the full wholesale price for curtailments, following the payment model described in FERC Order 745 subject to a net benefits test. However, this approach would result in over-incentivizing curtailments. Furthermore, the net benefits of Order 745 do not meaningfully transfer to the Ontario energy context due to the dominant role of the Global Adjustment. A second option would be compensating demand response participants at a "Wholesale Price minus G" rate, that is, the wholesale market price minus the generation component of their typical retail electricity bill. The correct marginal incentive for demand response customers to curtail consumption is the wholesale price, which is also the marginal system cost. For such the "Wholesale Price minus G" approach to work in Ontario, the 'G' component will need to be adjusted and the underlying demand response resources must have the same settlement arrangement. A third option, the "Retail Purchase and Wholesale Sellback" option, modelled after Australia's proposed design, would result in the same efficient marginal incentive. Additionally, this third option would enable new business models and provides greater visibility to the IESO. **Table 3** summarizes the status quo and the three options as evaluated using guiding principles from the Market Renewable Program.

We further evaluate three options for addressing the shutdown costs faced by some demand response participants: the status quo, in which participants bear the risk of longer-than-expected demand response events; two-part bids that are reflected in energy price formation; and two-part bids with make-whole payments for any unrecovered costs. While we find that the second of these might be the best solution for fully incorporating all resource costs, this option is also the most complex and does not lend itself to near-term implementation.

TABLE 3: SCORECARD FOR DIFFERENT ENERGY MARKET PAYMENT OPTIONS BASED ON MARKET RENEWAL PROGRAM'S GUIDING PRINCIPLES

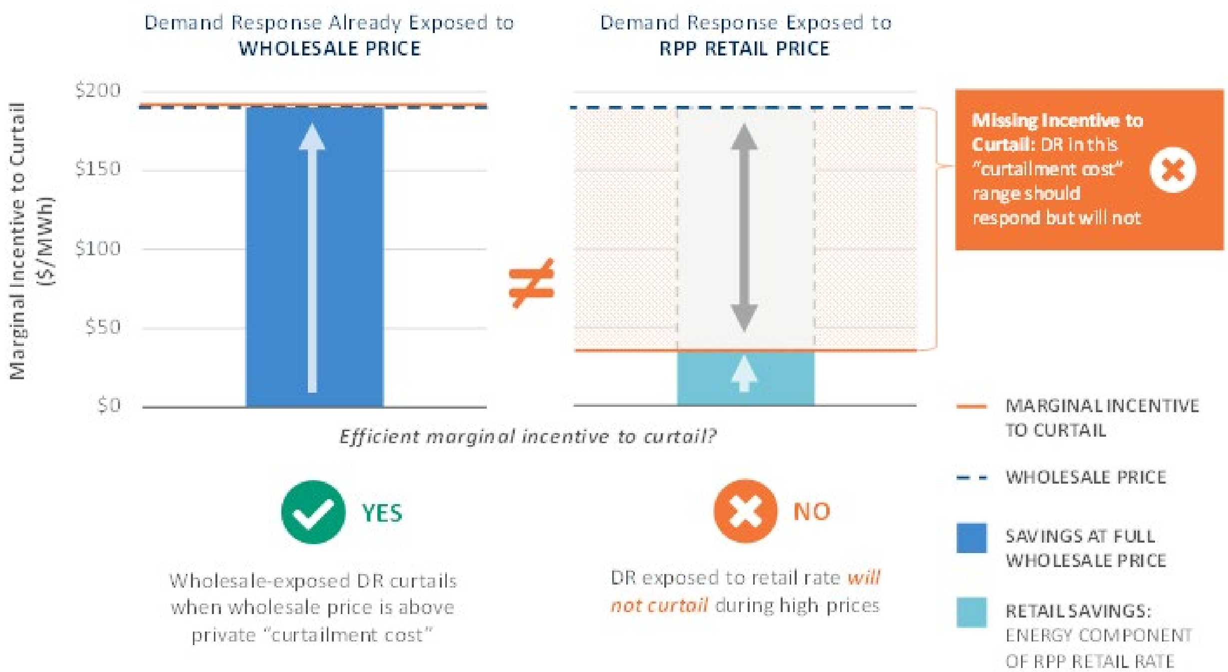
Metric	Status Quo	Full Wholesale Price Payment (subject to a Net Benefits Test)	Wholesale Price - G	Retail Purchase & Wholesale Sellback
Description	No energy market payments	Payments at full wholesale price	Payments at wholesale price minus generation component of retail rate	Payments at full wholesale price for curtailment of energy already purchased at retail rate
Efficiency	Low; demand response not exposed to wholesale price is under-incentivized	Low; demand response is over-incentivized	High; demand response is properly incentivized	High; demand response is properly incentivized
Competition	Low to Medium	Low to Medium	Low to Medium	High; new business modelsare enabled
Implementability	High; no changes are required	Medium; some changes are required	Low to Medium; significant rule and regulation changes are required	Low to Medium; significant rule and regulation changes are required
Certainty	Medium; offer prices do not fully contribute to energy market price formation at all time frames and locations	Medium	Medium	Medium
Transparency	Medium	Medium	Medium	High; demand response resources are visible and dispatchable to the IESO

A. MAINTAIN **STATUS QUO** WITH NO ENERGY MARKET PAYMENTS FOR ACTIVATIONS

The status quo does not offer energy market payments to demand response participants for activation, and continues to under-incentivize HDR participants to the extent that (unlike DL participants) they are not exposed to wholesale market price to curtail (see **Table 4** at the end of this subsection).

As explained in Section 2 of this report, demand response participants who are fully exposed to wholesale price already have the appropriate signal to curtail their energy consumption when wholesale price exceeds their private curtailment cost (see the left bar in **Figure 8** below). Dispatchable Load is this type of customer in Ontario. Dispatch Loads (scheduled and settled by the IESO on the 5-minute market schedule MCP) avoid paying the MCP when they curtail, and are eligible for make-whole (CMSC) payments whenever their dispatch schedule differs from their market schedule. On the other hand, HDR resources are not scheduled or settled in the real-time market, nor are they eligible for make-whole payments. Specifically, HDR contributors exposed to RPP or retail rates do not have the same incentive to curtail during high wholesale price hours. Depending on their arrangements, the incentive for HDR contributors to curtail is the payment avoided when not consuming power, which corresponds to the uniform HOEP, RPP, or retail rates. To the extent that there is a discrepancy between the MCP and the HOEP, RPP, or retail rates, there is a missing incentive for these contributors to curtail (see the right bar in **Figure 8** below). The difference between uniform prices and modelled locational shadow price, which is used for HDR dispatch criteria, is another disconnect under the status quo.

FIGURE 8: INCENTIVE TO CURTAIL FOR DEMAND RESPONSE UNDER THE STATUS QUO



Under the status quo, demand response resources do not always contribute to price formation. Dispatchable Loads can contribute to real-time price formation, but only to the extent that they offer at, are dispatched against, and are settled at the MCP. HDR resources can contribute to *pre-dispatch* price formation. However, in Ontario (and other markets) most demand response dispatches have the undesirable effect of artificially suppressing market prices when high prices are most needed. This occurs because out-of-market activations of demand response resources cause the pricing software to perceive lower system demand and, thus, produce a lower clearing price than it would if the demand response offer price were integrated into both dispatch and price formation.

Furthermore, in some instances, the basis for demand response activation may differ from what is used in settlement. Dispatchable Load customers may be activated ("constrained off") under the dispatch schedule, even if they would not be activated under the market schedule. In this scenario, CMSC payment serves as a partial remedy for Dispatchable Loads by making them whole relative to their market schedule.[89] On the other hand, HDR resources are not scheduled or settled in the energy market; they are 'activated' when the shadow price exceeds their bid in pre-dispatch at the location at which they are modelled. This means they are subject to activation under certain circumstances, but the avoided-cost remuneration of their underlying contributors may not always reflect the marginal system value. When activated out-of-market for testing purposes, HDR resources receive a fixed payment of $250/MWh curtailed and no energy payments. Similarly, per out-of-market activation hour in an emergency event, HDR resources receive a payment that is equal to the per hour bid price minus HOEP. While these payments make the HDR participants whole relative to their costs, they do not necessarily reflect the full system value, which is what the market price would have been without emergency demand response activation.

Under Market Renewal, the Single Schedule Market will introduce nodal prices (LMPs). By being settled and dispatched on nodal prices, Dispatchable Loads will receive economically efficient price signals and will modify their consumption patterns based on their private curtailment cost. HDR resources will continue to be neither scheduled nor settled in the real-time energy market. HDR contributors settled on the HOEP today will instead settle on the zonal price once Market Renewal is implemented. A disconnect could still exist because HDRs are activated against nodal price triggers, but the underlying contributors are settled at lower zonal prices (which may differ from the nodal price). Furthermore, as long as HDR resources remain unable to contribute to price formation, there will be a disconnect between uniform price and basis for dispatch; they may be activated in pre-dispatch but are settled at a lower real-time prices. Finally, out-of-market activation instances where HDR resources do not receive remuneration that reflects the marginal system value will continue as well.

[89] We discuss options to address shutdown costs in Section C of this report.

TABLE 4: DEMAND RESPONSE COMPENSATION UNDER STATUS QUO — NO ENERGY MARKET PAYMENTS FOR ACTIVATION

	DISPATCHABLE LOAD (DL)		HOURLY DEMAND RESPONSE (HDR)	
	Before Market Renewal	**After Market Renewal**	**Before Market Renewal**	**After Market Renewal**
	When is Demand Response Dispatched?			
Trigger for Dispatch	**In-Market:** Real-time constrained dispatch shadow price exceeds DL's energy bid price	**In-Market:** LMP exceeds DL's energy bid price	**In-Market:** 3-hour ahead; and constrained pre-dispatch modelled shadow price exceeds HDR energy offer price	**In-Market:** 3-hour ahead; modelled LMP exceeds HDR energy bid price
	Out-of-Market: can be manually dispatched for test activations and emergency events	**Out-of-Market:** can be manually dispatched for test activations and emergency events	**Out-of-Market:** test activations and emergency events	**Out-of-Market:** test activations and emergency events
	What are the Incentives to Curtail?			
Bill Savings	DL customers save at the full wholesale price	DL customers save at the full nodal LMP	Based on their arrangements, HDR contributors save at the HOEP, RPP, or retail rate for reduced consumption	Contributors who previously saved at the HOEP now save at zonal LMP. No changes for contributors with RPP or retail rates
+ Energy Payments	DL customers **DO NOT** receive additional energy market payments for activation		HDRs do not receive additional energy market payments for dispatch	
+ Make-Whole Payments	DL customers may receive a CMSC payment if dispatch schedule differs from market schedule	DL customers no longer receive CMSC payments under Single Schedule Market as dispatch and settlement are both based on LMP	HDR resources receive compensation when activated out of market ($250/MWh for test activation and bid minus HOEP for emergency activation). No make-whole payments when settlement price (zonal/RPP/retail) differs from dispatch price	
– Global Adjustment	**Class A** customers are settled based on their share of system-wide consumption during the five peak hours of the year multiplied by system-wide Global Adjustment costs **Class B** and **RPP** customers are billed by the LDC at a monthly rate in cents/kWh			
	Is Marginal Incentive to Respond Equal Marginal System Value?			
	Yes Customer is exposed to wholesale market price	Yes Customer is exposed to wholesale market price	No RPP and retail customers are not exposed to wholesale market price	No RPP and retail customers are not exposed to wholesale market price

B. PAYMENTS FOR CURTAILING CONSUMPTION IN HIGH-PRICED HOURS

As explained in Section 2 of this report, demand response customers exposed to real-time wholesale power prices already have the appropriate level of incentive, the marginal system cost, to respond. On the other hand, customers exposed to retail (RPP) rates are not properly incentivized to curtail their energy consumption, even when wholesale prices spike to very high levels. For this reason, we only explore energy market payment options to restore the incentives to response for demand response customers that are only exposed to the retail price.

1. Full Wholesale Price above a Customer Benefits "Threshold Price"

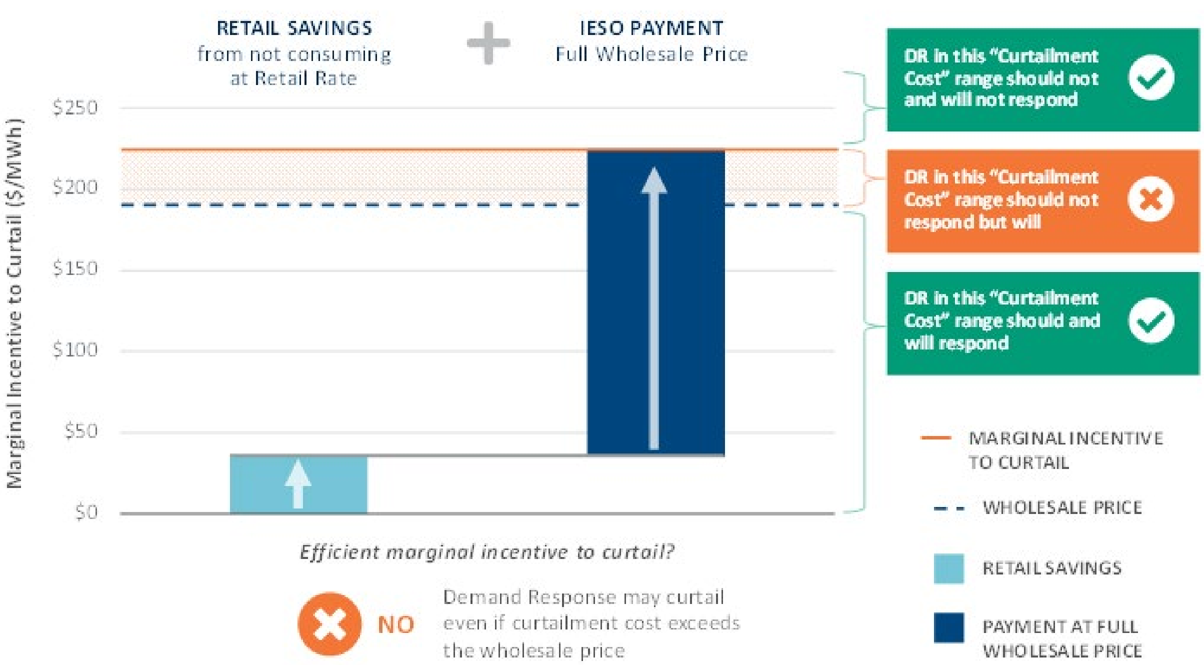
Energy payment at full wholesale prices follows the payment model prescribed in FERC Order 745. In this option, the demand response participant receives a payment at full wholesale price for every curtailed energy unit. **Figure 10A** and **Figure 10B** illustrate how this payment option can result in over-incentivizing curtailments. In **Figure 10A**, the wholesale-exposed demand response contributor consumes electricity at a wholesale price of $190/MWh. The marginal incentive to curtail would be the savings at the full wholesale price ($190/MWh) from not consuming plus the payment from the IESO to curtail (the wholesale price of $190/MWh), for a total of $380/MWh. If the curtailment cost exceeds $380/MWh (the marginal incentive to curtail), it would not be economic to reduce consumption—an efficient outcome. If the curtailment cost is below the wholesale price, it would be economic to curtail consumption; also an efficient outcome. However, if the curtailment cost is between $190/MWh and $380/MWh, this compensation model would provide an *inefficient* incentive to curtail, because the $190/MWh wholesale price is still lower than the curtailment cost. This inefficient outcome is realized because the full wholesale payment compensates the demand response participant *in addition* to the savings from not consuming at the wholesale rate.

The inefficient outcome exists for demand response customers who are exposed to retail rates as well. As shown in **Figure 10B**, the net marginal incentive to curtail would be $225/MWh (retail rate savings of $35/MWh plus the $190/MWh payment from the IESO). If the curtailment cost is between $190/MWh and $225/MWh, this compensation model would result in an *inefficient* outcome: the customer would have an incentive to curtail even though the wholesale price is lower than the curtailment cost.

Another limitation of the FERC 745 approach is that it implies a preference for transfer payments from suppliers to consumers. The net benefits that customers obtain are at the expense of generators supplying less electricity to the market. This perspective is not consistent with competitive wholesale markets. Instead, a marginal benefit approach with the goal of maximizing societal benefits is more appropriate—demand response activation should start to take place only when the marginal cost of curtailment is equal to the marginal benefit to the system.

FIGURE 10A: INCENTIVE TO CURTAIL FOR WHOLESALE-EXPOSED DEMAND RESPONSE UNDER FULL WHOLESALE PAYMENTS

FIGURE 9B: INCENTIVE TO CURTAIL FOR RETAIL-EXPOSED DEMAND RESPONSE UNDER FULL WHOLESALE PAYMENTS



Because of the dominant role of the Global Adjustment, the FERC Order 745 net benefits test does not meaningfully transfer to the Ontario context. As discussed in Section 2 of this report, the recovery of Global Adjustment charges counteracts total customer savings associated with price reductions. As we illustrate in the appendix, this dynamic results in different net effects for Class A and Class B customers. Both classes of customers benefit from the price reduction when demand response is triggered. However, Class B customers experience a disproportionate increase in Global Adjustment charges relative to Class A customers. In essence, Class A customers transfer the Global Adjustment charges that they would incur to Class B customers. As a result, Class A customers receive a net positive benefit, whereas Class B customers see an increased cost (i.e., negative benefit). In fact, we find that customer cost reductions from energy price reductions are offset on a nearly one-to-one basis by customer cost increases from Global Adjustment charges at all price levels. Class A customers would be more likely to earn a net benefit, but at the expense of Class B customers.

Finally, limiting compensation only when prices exceed the "threshold price" wrongly implies that demand response responsiveness has no value at lower price levels. On the contrary, demand response has value at all levels, as represented by the changes in wholesale energy price with and without demand response activated.

Table 5 below summarizes how a demand response providers would be compensated in Ontario if an additional energy payment was added for HDR activation at a level equal to the full wholesale market price. The differences to the status quo are indicated in orange shading. As discussed, this option would not provide proper incentives because it would overcompensate DR contributors. Additional energy payment for DL customers would not be necessary as they are already exposed to the wholesale market prices and thus realize savings equal to the full wholesale price if activated.

TABLE 5: DEMAND RESPONSE COMPENSATION UNDER **FULL WHOLESALE PRICE** COMPENSATION FOR HDR RESOURCES ONLY (NO ADDITIONAL COMPENSATION FOR DISPATCHABLE LOADS)

	DISPATCHABLE LOAD (DL)		HOURLY DEMAND RESPONSE (HDR)	
	Before Market Renewal	**After Market Renewal**	**Before Market Renewal**	**After Market Renewal**
When is Demand Response Dispatched?				
Trigger for Dispatch	**In-Market:** Real-time constrained dispatch shadow price exceeds DL's energy bid price	**In-Market:** LMP exceeds DL's energy offer price	**In-Market:** 3-hour ahead; and constrained pre-dispatch modelled shadow price exceeds HDR energy offer price	**In-Market:** 3-hour ahead; modelled LMP exceeds HDR energy bid price
	Out-of-Market: can be manually dispatched for test activations and emergency events	**Out-of-Market:** can be manually dispatched for test activations and emergency events	**Out-of-Market:** test activations and emergency events	**Out-of-Market:** test activations and emergency events
What are the Incentives to Curtail?				
Bill Savings	DL customers save at the full wholesale price	DL customers save at the full nodal LMP	Based on their arrangements, HDR contributors save at the HOEP, RPP, or retail rate for reduced consumption	Contributors previously saved at the HOEP now save at zonal LMP. No changes for contributors with RPP or retail rates
+ Energy Payments	DL customers **DO NOT** receive additional energy market payments for activation		HDRs contributors receive payments equal to the ***full wholesale (HOEP) price*** regardless of their settlement arrangement	HDR contributors receive payments equal to ***the full zonal LMP*** regardless of their settlement arrangement
+ Make-Whole Payments	DL customers may receive a CMSC payment if dispatch schedule differs from market schedule	DL customers no longer receive CMSC payments under Single Schedule Market as dispatch and settlement are both based on LMP	HDR resources receive compensation when activated out of market ($250/MWh for test activation and bid minus HOEP for emergency activation) No make-whole payments when settlement price (zonal/RPP/retail) differs from dispatch price	
– Global Adjustment	**Class A** customers are settled based on their share of system-wide consumption during the five peak hours of the year multiplied by system-wide Global Adjustment costs **Class B** and **RPP** customers are billed by the LDC at a monthly rate in cents/kWh			
Is Marginal Incentive to Respond Equal Marginal System Value?				
	Yes Customer is exposed to wholesale market price	Yes Customer is exposed to wholesale market price	No HOEP, RPP, and retail customers are over-incentivized to curtail	No HOEP, RPP, and retail customers are over-incentivized to curtail

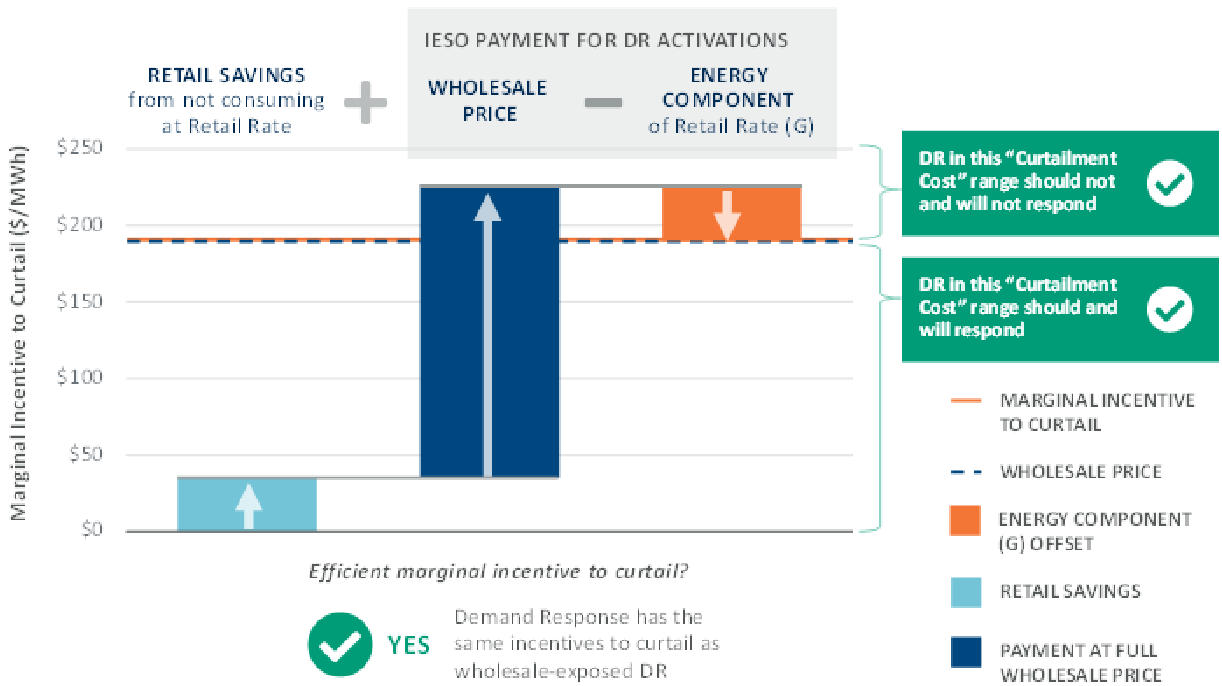
Notes: Orange shading indicates changes relative to the Status Quo; gray shading indicates no changes.

2. Compensation at "Wholesale Price minus G"

Modeled after certain U.S. ISO/RTO jurisdictions prior to FERC 745, this payment option compensates demand response participants at a "Wholesale Price minus G" rate during curtailment events. In this model, contributors and the LDC would be charged at their post-curtailment realized consumption. Demand response provider would be compensated at the wholesale price less the generation component of the contributor's retail bill. For any contributors who are exposed to the full wholesale price (HOEP), an additional energy payment would not be necessary as "Wholesale Price minus G" would be zero. For HDR contributors with RPP, however, "G" would be based the forecast <u>average</u> HOEP component (not including the Global Adjustment charge) of their bill.

While the FERC Order 745 payment option results in double payment—payment at wholesale price on top of savings from not consuming energy—the Wholesale Price minus G model restores the curtailment incentive to an appropriate level. **Figure 11** illustrates this dynamic. The marginal incentive for the demand response participant to respond would be reduced by the energy component of the retail rate, from $225/MWh to $190/MWh. The marginal incentive would be at the same level as the wholesale price, or the system marginal cost, resulting in efficient outcomes.

FIGURE 10: INCENTIVE TO CURTAIL FOR RETAIL-EXPOSED DEMAND RESPONSE UNDER WHOLESALE PRICE MINUS G PAYMENTS



We recognize that in practice, the contributor's consumption level depends on the entire retail rate, not just the generation component. This includes the transmission, distribution, and Global Adjustment charges, among others. To the extent that the contributor does not pay these non-generation components on a volumetric basis, the marginal incentive is efficient. However, if non-generation components are assessed on a volumetric basis—and they are in Ontario—these retail rate components magnify contributor's benefits from curtailments. As a result, the "G" component would need to be adjusted to account for all volumetric charges, not just generation-related components.

Additionally, in order for this model to work, the aggregators would have to ensure that all of the demand response resources have the same retail rate arrangement. That is, all their resources would have to be aggregated by their retail settlement type (HOEP, RPP, or retail rate). Otherwise, the marginal incentive would not be efficient for all of the participating contributors.

Table 6 below summarizes how a demand response provider would be compensated in Ontario if an additional energy payment was added for HDR activation at a level equal to "wholesale price minus G." The differences to the status quo are indicated in orange shading. As discussed, this option would provide proper incentives to HDR contributors. Again, additional energy payment for DL customers would not be necessary because they are already exposed to the wholesale market prices and thus realize savings equal to the full wholesale price if activated.

TABLE 6: DEMAND RESPONSE COMPENSATION UNDER WHOLESALE PRICE – G COMPENSATION FOR HDR RESOURCES ONLY (NO ADDITIONAL COMPENSATION FOR DISPATCHABLE LOADS)

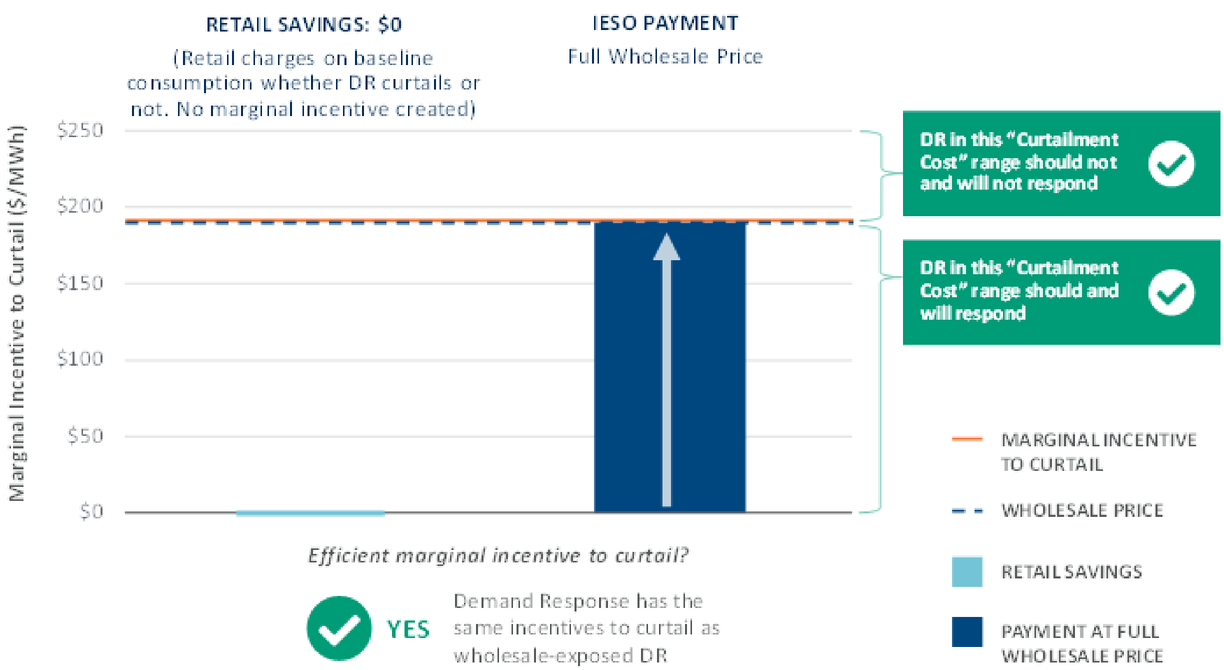
	DISPATCHABLE LOAD (DL)		HOURLY DEMAND RESPONSE (HDR)	
	Before Market Renewal	**After Market Renewal**	**Before Market Renewal**	**After Market Renewal**
When is Demand Response Dispatched?				
Trigger for Dispatch	**In-Market:** Real-time constrained dispatch shadow price exceeds DL's energy bid price **Out-of-Market:** can be manually dispatched for test activations and emergency events	**In-Market:** LMP exceeds DL's energy bid price **Out-of-Market:** can be manually dispatched for test activations and emergency events	**In-Market:** 3-hour ahead; and constrained pre-dispatch modelled shadow price exceeds HDR energy offer price **Out-of-Market:** test activations and emergency events	**In-Market:** 3-hour ahead; modelled LMP exceeds HDR energy offer price **Out-of-Market:** test activations and emergency events
What are the Incentives to Curtail?				
Bill Savings	DL customers save at the full wholesale price	DL customers save at the full nodal LMP	Based on their arrangements, HDR contributors save at the HOEP, RPP, or retail rate for reduced consumption	Contributors previously saved at the HOEP now save at zonal LMP. No changes for contributors with RPP or retail rates
+ Energy Payments	DL customers **DO NOT** receive additional energy market payments for activation		HDR contributors receive payments (from DR aggregator) equal to Wholesale (HOEP) minus G regardless of their settlement arrangement	HDR contributors receive payments (from DR aggregator) equal to LMP minus G regardless of their settlement arrangement
+ Make-Whole Payments	DL customers may receive a CMSC payment if dispatch schedule differs from market schedule	DL customers no longer receive CMSC payments under Single Schedule Market as dispatch and settlement are both based on LMP	HDR resources receive compensation when activated out of market ($250/MWh for test activation and bid minus HOEP for emergency activation) No make-whole payments when settlement price (zonal/RPP/retail) differs from dispatch price	
– Global Adjustment	**Class A** customers are settled based on their share of system-wide consumption during the five peak hours of the year multiplied by system-wide Global Adjustment costs **Class B** and **RPP** customers are billed by the LDC at a monthly rate in cents/kWh			
Is Marginal Incentive to Respond Equal Marginal System Value?				
	Yes Customer is exposed to wholesale market price	Yes Customer is exposed to wholesale market price	Yes Marginal incentive is equal to wholesale market price	Yes Marginal incentive is equal to wholesale market price

Notes: Orange shading indicates changes relative to the Status Quo; gray shading indicates no changes.

3. Retail Purchase with Wholesale Sellback

In this option, modelled after Australia's proposed demand response program, the IESO would charge the contributors or LDCs according to their baseline energy consumption. The IESO would then compensate the registered demand response market participant for every curtailed MWh at the full wholesale price. In the Ontario context, the demand response market participant can be an aggregator (such as for HDR), the LDC, or the retailer. If the DR market participant is an aggregator, it would reimburse the LDC or retailer for the "purchase" of the curtailed MW at a reimbursement rate, which should be close to the retail rate. As a result, this option offers an economically efficient incentive to demand response participants as shown in **Figure 12** – with overall incentives at the same level as under the "Wholesale Price minus G" option.

FIGURE 11: INCENTIVE TO CURTAIL FOR RETAIL-EXPOSED DEMAND RESPONSE UNDER RETAIL PURCHASE AND WHOLESALE SELLBACK



We recommend that the current HDR program be used as a template for this approach. Currently, HDR participants are already evaluated on a baseline consumption when activated.[90] A demand response aggregator may have a mix of commercial and industrial contributors, some of whom may pay the HOEP while others pay the RPP or retail rate. An aggregator may also have contributors who are customers of different LDCs. The aggregator may report the metered data from its contributors, but the IESO would evaluate the aggregator on a total basis (rather than on an individual contributor basis). Virtual residential

90 Currently Physical HDRs and C&I Virtual HDRs are evaluated on 'baseline' consumption when activated. The baseline is determined based on average actual consumption in the past highest 15 of 20 business days, coupled with an in-day adjustment factor. The baseline for the latter group is assessed on an aggregate level instead of individual contributor performance. Baseline for residential Virtual HDRs is determined by looking at the difference of behavior between the control and treatment group. These baseline determination methods may continue to apply for this payment option, though it is beyond the scope of this paper to evaluate their appropriateness and effectiveness.

HDR resources would be evaluated by comparing the difference in behavior of the control group and treatment group.

In the proposed model, the IESO would assess the consumption baseline on an aggregator basis. The aggregator would have to ensure that the underlying contributors have the same settlement arrangement, namely, the contributors are not already exposed to the full wholesale market price. Importantly, contributors in this arrangement would have to have the same settlement entity, be it the IESO, the retailer, or the LDC. Alternatively, the aggregators could directly settle with the settlement entity on behalf of their contributors. At the moment, aggregators can receive out-of-market markets and capacity payments, so in theory, they could perform the additional energy payment settlement function as well. However, we note that this change would present an implementation challenge, as Ontario regulators would need to amend relevant rules and regulations to enable aggregators to participate directly in the energy market.[91]

In addition to providing an economically efficient incentive for retail-exposed demand response resources to curtail during high-priced hours, this retail purchase and wholesale sellback option is advantageous for two additional reasons. First, it provides an avenue for third-party demand response providers to participate in the wholesale market without having to become a full retailer or energy service company. (Aggregators in Ontario currently participate in a version of this model as Virtual HDR resources, but they are not able to settle for energy payments.) Second, demand response in this supply-side participation model becomes visible and dispatchable to the IESO. Under the status quo, HDR can continue to submit energy bids but are unable to settle. The proposed model would enable demand response resources to participate in the energy market more actively, making visible to the system operator their willingness to pay at different price levels.

Table 7 below summarizes how a demand response market participant (such as an HDR contributor) would be compensated in Ontario, if the retail purchase and wholesale sellback option was implemented for demand response activation. The differences to the status quo are indicated in orange shading. As discussed, this option would provide proper incentives to retail-exposed customers who do not have the proper incentives to curtail under the status quo. Again, additional energy payment for DL customers would not be necessary as they are already exposed to the wholesale market prices.

91 The model can apply on an individual contributor basis as well, where the IESO would directly settle with the contributors, as is the case of Physical HDR today. However, there may be some efficiency limitations as this model is scaled up to include all HDR resources.

TABLE 7: DEMAND RESPONSE COMPENSATION UNDER RETAIL PURCHASE AND WHOLESALE SELLBACK COMPENSATION FOR HDR RESOURCES ONLY (NO ADDITIONAL COMPENSATION FOR DISPATCHABLE LOADS)

	DISPATCHABLE LOAD (DL)		HOURLY DEMAND RESPONSE (HDR)	
	Before Market Renewal	After Market Renewal	Before Market Renewal	After Market Renewal
When is Demand Response Dispatched?				
Trigger for Dispatch	**In-Market:** Real-time constrained dispatch shadow price exceeds DL's energy bid price **Out-of-Market:** N/A	**In-Market:** LMP exceeds DL's energy bid price **Out-of-Market:** N/A	**In-Market:** 3-hour ahead; and constrained pre-dispatch modelled shadow price exceeds HDR energy offer price **Out-of-Market:** test activations and emergency events	**In-Market:** 3-hour ahead; modelled LMP exceeds HDR energy bid price **Out-of-Market:** test activations and emergency events
What are the Incentives to Curtail?				
Bill Savings	DL customers save at the full wholesale price	DL customers save at the full nodal LMP	Based on their arrangements, HDR contributors save at the HOEP, RPP, or retail rate for reduced consumption	Contributors previously saved at the HOEP now save at zonal LMP. No changes for contributors with RPP or retail rates
+ Energy Payments	DL customers **DO NOT** receive additional energy market payments for activation		HDR contributors receive (from DR aggregator) payments for curtailment: up to wholesale (HOEP) price less the DR aggregator's reimbursement to the LDC or retailer	HDR contributors receive (from DR aggregator) payments for curtailment: up to zonal LMP less the DR aggregator's reimbursement to the LDC or retailer
+ Make-Whole Payments	DL customers may receive a CMSC payment if dispatch schedule differs from market schedule	DL customers no longer receive CMSC payments under Single Schedule Market as dispatch and settlement are both based on LMP	HDR resources receive compensation when activated out of market ($250/MWh for test activation and bid minus HOEP for emergency activation) No make-whole payments when settlement price (zonal/RPP/retail) differs from dispatch price	
– Global Adjustment	**Class A** customers are settled based on their share of system-wide consumption during the five peak hours of the year multiplied by system-wide Global Adjustment costs **Class B** and **RPP** customers are billed by the LDC at a monthly rate			
Is Marginal Incentive to Respond Equal Marginal System Value?				
	Yes Customer is exposed to wholesale market price	Yes Customer is exposed to wholesale market price	Yes Marginal incentive is equal to wholesale market price	Yes Marginal incentive is equal to wholesale market price

Notes: Orange shading indicates changes relative to the Status Quo; gray shading indicates no changes.

C. OPTIONS TO ADDRESS SHUTDOWN COSTS

As discussed in Section 2, demand response participants with shutdown costs currently face the risk of unrecovered shutdown costs associated with uncertainty in the duration of activation events. In **Table 8** and as discussed below, we evaluate three options for addressing demand response shutdown costs:[92]

- **Status Quo: One-Part Bids (participant bears event-duration risk).** Under the current market rules, demand response participants can incorporate shutdown costs in within a one-part energy bid. To levelize shutdown costs, the participant must estimate the expected duration of activation. For example, HDR participants may levelize their shutdown costs over a period of up to four hours, depending on how long they think the activation period will last. When the participant is an aggregator, they would have to consider in their bid the fixed costs of the underlying contributors. Because the dispatch order and clearing price (on average) incorporate these shutdown costs, this approach contributes to appropriate market price formation, to the extent that participants can accurately predict event durations. However, participants face the risk of unrecovered shutdown costs (a risk that generators eligible for unit commitment guarantee payments do not face).
- **Two-Part Demand-Response Bids Reflected in Energy Price Formation.** In our recommended approach, the demand response participant reports two separate components when submitting the energy bid: the variable component (in $/MWh) and the shutdown component (in $/MW), subject to audit and verification. Just as it does for generation start-up and dispatch costs, the IESO would consider both of these elements at all timeframes and optimize total cost in the enhanced reliability unit commitment (ERUC) and security constrained economic dispatch (SCED) processes. This would optimally dispatch demand response and generation on an equal basis, considering both variable costs and the levelized the shutdown costs across the anticipated duration of the activation. We anticipate that this improved commitment and dispatch approach can be readily incorporated into the day-ahead, ERUC, and real-time market operations using dispatch methods identical or similar to those already offered to generators. A more challenging aspect of this approach is that we additionally recommend that both cost components would be reflected in energy market price formation, with prevailing market prices set at or above variable plus levelized start-up costs when demand response is called.
- **Two-Part Bids with Make-Whole Payments for Any Unrecovered Costs.** As a final option, if pricing or dispatch approaches cannot fully incorporate demand response shutdown costs, then IESO can use a make-whole payment to reimburse demand response participants for any unrecovered shutdown costs, which are subject to audit and verification. This would award demand response participants a full compensation guarantee similar to that currently offered to generators. The downside of this approach is that out-of-market payments signal an unaddressed market inefficiency (in this case, either inefficiently low prices or excess demand response dispatch). It would be better to address the underlying inefficiency and avoid such a make-whole payment if possible.

Of these options, we recommend pursuing Option 2 as the first-best solution for fully incorporating all resource costs into the most efficient dispatch and price formation. However, we recognize that this is

[92] We recommend that similar to startup costs incurred by generators, these shutdown costs be either audited or pre-approved based on verification process.

also a more complex option. It would not be possible to implement in the near term, and some elements (most notably incorporating shutdown costs into price formation) may be very challenging to implement even after the introduction of the more advanced energy market software with Market Renewal. Thus, we recommend the pursuit of Option 2 to the extent possible and as soon as possible, while incorporating elements of the second-best alternatives, under Options 1 and 3, as necessary in the interim.

TABLE 8: EVALUATION OF OPTIONS FOR ADDRESSING DEMAND RESPONSE SHUTDOWN COSTS

Approach	1. Status Quo: One-Part Bids (Participant Bears Event Duration Risk)	2. Two-Part Bids Reflected in Energy Price Formation (Recommended)	3. Two-Part Bids with Make-Whole Payments for Any Unrecovered Costs
Description	• Participant incorporates variable costs and levelized shutdown costs in a one-part energy market bid in $/MWh	• Participant submits two-part bids including: a variable $/MWh component and (optional) an additional $/MW shutdown cost component • IESO commitment and dispatch instructions optimally incorporate both elements • Price formation incorporates the demand response offer at variable cost plus levelized shutdown costs (ensuring prices equal or exceed resource costs)	• Same as Option 2, but price formation would not include levelized shutdown costs. • Participants can receive out-of-market make-whole payments if prices over the curtailment interval are lower than the sum of variable plus shutdown costs
Example of How it Works Assume a resource with $300/MW shutdown costs + $500/MWh variable costs	• Participant guesses an expected event duration of 2 hours, thus bidding at $650/MWh ($500/MWh + $300/MW ÷ 2 hours)	• Participant offers at $500/MWh (variable) plus $300/MW (shutdown) • IESO uses SCED to optimize resource dispatch • Prices reflect both components of resource cost when the resource is marginal (*e.g.* $800/MWh for a 1-hour event; $650/MWh for a 2-hour event)	• Same as Option 2 • If realized prices over a 2-hour dispatch interval are $500/MWh, then IESO would award $150/MWh in make-whole payments ($650/MWh levelized resource costs minus $500/MWh in average prices)

Approach	1. Status Quo: One-Part Bids (Participant Bears Event Duration Risk)	2. Two-Part Bids Reflected in Energy Price Formation (Recommended)	3. Two-Part Bids with Make-Whole Payments for Any Unrecovered Costs
Advantages	• Proper price formation, but only to the extent that participants accurately predict event duration	• Most efficient price formation • Most efficient dispatch efficiency • Reduced uncertainty to DR provider (some uncertainty remains at the timing of dispatch instructions)	• Most efficient dispatch efficiency and price formation (to the extent possible in IESO software) • Participant is guaranteed shutdown cost recovery • Equivalent treatment with generators
Disadvantages	• Participant faces uncertainty in how to bid • Participant may not recover shutdown costs • Disadvantage relative to generators	• Most challenging to implement in IESO price formation software	• Inefficiencies associated with out-of-market make-whole payments • Prices may not reflect shutdown costs

V. Recommendations

A. RECOMMENDATIONS: IMMEDIATE QUESTIONS RAISED BY STAKEHOLDERS

The IESO has made a number of advancements over recent years to enable and support demand response to participate in the wholesale markets. At the same time, the pace of technological and industry advancement in the area of customer responsiveness potential will present many more opportunities to offer beneficial services to customers and the grid that are not yet enabled by current market rules. To enable demand response players to participate more fully in the wholesale energy market, we believe that additional compensation models should be offered within the wholesale energy market to facilitate the full participation of demand response. These compensation models should send the right signal to reduce consumption during high-priced (especially system scarcity) events—and to possibly also increase consumption during low-priced (especially surplus baseload generation) events. These price signals should not over-compensate demand response providers beyond the marginal value they provide to the system.

In pursuing that outcome, **we do not recommend adopting a customer benefits test and full-wholesale-price payments** approach similar to what has been adopted in most U.S. markets under FERC Order 745. We recommend against the FERC model for three reasons. First, the model over-incentivizes curtailments relative to marginal system value. Second, a customer-benefits test implies a preference for transfer payments from suppliers to consumers, rather than taking a societal benefits perspective that is more consistent with competitive wholesale markets. Third, the U.S. customer benefits test approach does not meaningfully transfer to the Ontario context given the dominant role of the Global Adjustment. Customer cost reductions from energy price reductions are offset on a nearly one-to-one basis by customer cost increases from Global Adjustment charges at all price levels, with large Class A customers more likely to earn a net benefit, but at the expense of smaller Class B customers.

To provide efficient curtailment incentives during periods of high wholesale market prices for retail customers who are not already exposed to the full wholesale market price, we recommend awarding additional payments to demand response for any wholesale energy-market curtailments. The payment would be consistent with providing incentives equivalent to the incremental system value. Such payments for energy market participation can enable more market participation, greater development of the demand response market, more system flexibility, and greater overall value. We recommend offering either one or both of the following wholesale energy compensation models for HDRs with demand response contributors who are not exposed to the wholesale price:

- **Retail Purchase and Wholesale Sellback** (similar to the Australian proposed approach) in which the contributor's settlement would be separated into two components with: (1) a retail purchase, for which the IESO would charge customers or LDCs at their baseline (pre-curtailment) energy consumption; and separately (2) a wholesale sellback, for which the IESO would pay the registered DR market participant for the curtailed MWh at the full wholesale energy market price.
- **Curtailment Payments at the Wholesale Price minus the Generation Component of Retail Rates** (similar to the 'LMP-G' previously used in the U.S.) in which the contributors or the LDC would be

charged at their post-curtailment realized consumption, and the demand response provider would be compensated at the wholesale price minus the variable (generation) component of the customer's retail bill ("Wholesale Price minus G").

Both of these models offer economically efficient economic signals for demand response curtailment and energy market participation. Because there is no IESO energy settlement associated with HDR resources—and no uniform settlement of underlying contributors—and a limited retail sector, we recognize that significant changes would need to be considered in order to implement either option in Ontario. Overall, we recommend the *Retail Purchase and Wholesale Sellback* model, as it offers the most promising avenue to enable economically efficient market participation for the widest range of demand response resource types and business models.

Additionally, we find that for some types of demand response resources, the value of lost load (VOLL) is most naturally reflected by the sum of (1) fixed (including 'shutdown') costs expressed in dollars per MW or dollars per activation; plus (2) variable costs expressed in dollars per MWh. Currently, offer prices in Ontario can only include a dollar per MWh component, which means that demand response players face uncertainty in the proper way to offer due to the uncertainty in the duration of the activation event. A resource with $300/MW in shutdown costs and $500/MWh in variable costs should offer into the market (and set prices) at $575/MWh for a four-hour event or $1,700/MWh for a 15-minute event. We recommend that offer prices, dispatch, and wholesale price formation should account for both types of resource costs.[93] We recommend allowing demand response to bid both types of costs separately, and adjusting price formation to account for both variable plus shutdown costs (divided by event duration) explicitly. If this is not feasible, we recommend a second-best alternative by either: (1) enabling demand response to incorporate both types of costs into their offer price in dollar per MWh (which would maintain the problem of unrecovered costs associated with uncertain event durations); or (2) introducing a make-whole payment to compensate for any unrecovered shutdown costs (which would address the current problem of unrecovered costs, but introduce the new problem of an out-of-market payment).

B. BROADER RECOMMENDATIONS FOR FULLY ENABLING DEMAND RESPONSE IN THE ENERGY MARKET

Beyond the above recommendations, we find there are a number of ways that demand response can be incorporated into the energy market more fully. While the following recommendations may not directly address stakeholders' immediate concerns, and they may be challenging to implement in the near term due to the scope of work involved, they may help to enhance demand response participation in the future.

- **Align demand response resources' dispatch signals and settlements with day-ahead and real-time LMPs** (post Market Renewal; or using the currently used nodal "shadow prices"). If adopted, our recommendations would lead to more demand response sellers offering into the energy market at their private value of energy consumption (*i.e.*, private cost of voluntary curtailment). We recommend that these resources should be dispatched and settled if (and only if) the marginal

93 In PJM, the system operator addresses this issue by allowing demand response to submit energy offers in the day-ahead energy market that include shutdown cost, variable cost, and minimum downtime components.

system value of energy (*i.e.*, the nodal day-ahead or real-time price) exceeds the resource's private offer price. This would ensure that demand response is called only when it is the least-cost resource available to the system, which preserves incentives to offer at the true resource cost. To reduce the frequency of out of market dispatches, we recommend identifying any instances of such out-of-market DR dispatch and evaluate whether these can be transitioned into a system of market-based dispatch against day-ahead or real-time LMPs (after Market Renewal) or the nodal "shadow price" (under the current two-schedule market). Currently Dispatchable Loads are eligible for CMSC payments whenever their dispatch schedule deviates from their market schedule. There is no similar basis for HDR, in part because there is no energy settlement. However, both HDRs and DLs are compensated for certain non-market dispatch instructions, such as during system emergency events. However, even during emergency events DR resources should not be activated until prices reach their offer price (which may often be the price cap). (We recognize that out-of-market test activations for the purposes of capacity market participation will still be necessary if energy market prices are not high enough to trigger a sufficient number of in-market activations.)

- **If DR dispatches at settlement prices below DR dispatch costs cannot be resolved in the near term, offer make-whole payments for any such out-of-market dispatch** (while working to reduce the frequency of such events). If our above recommendations are implemented, there would not be any occasions when a demand resource is dispatched at wholesale prices below their offer price. Thus, there would not be any occasions in which make-whole payments are needed. However, we understand it would be challenging to achieve this ideal outcome in the near term. Therefore, we recommend awarding make-whole payments to demand response resources whenever their market payments undercompensate them relative to either system value or relative to their individual resource cost. Before Market Renewal is implemented this would mean that when activated, HDRs would be paid at the pre-dispatch nodal shadow price minus the resource's weighted average HOEP-based wholesale settlement price in that event. For any out-of-market dispatches or test activations, we recommend to compensate the resource an amount equal to the differences between the resource's offer price and market prices. After Market Renewal, we anticipate many of these make-whole payments could be eliminated with the introduction of a day-ahead market and locational pricing. However, make-whole payments should continue to the extent that: (1) demand response is dispatched against nodal prices but loads are settled at lower zonal prices; (2) demand response is economically activated in pre-dispatch but settled at lower real-time prices; or (3) demand response is dispatched on a non-market or test basis when prices are below their offer price.
- **Incorporate demand-resource offer prices into energy market price formation.** The corollary to the prior recommendation is to ensure that demand response resources' offer prices can contribute to energy market price formation at all timeframes and locations. This will improve the ability of wholesale prices to signal times and locations of system stress, thereby signaling demand response and other resources to react. Currently DLs can contribute to real-time price formation but only when they are dispatched against the five-minute Market Clearing Price (as opposed to for reliability reasons). HDR resources can similarly contribute to pre-dispatch price formation. However, in practice in Ontario (and other markets), most demand response dispatches have the undesirable effect of artificially suppressing market prices right when high prices are most needed. This occurs because out-of-market DR dispatches cause the pricing software to perceive lower system demand and, thus, produce a lower clearing price than it would if the DR offer price had been integrated into both dispatch and price formation. We recommend correcting this underpricing issue and restore

market prices to a level at or above demand resources' offer prices whenever they are dispatched. Prior to Market Renewal, this would primarily mean ensuring that the marginal cost of any emergency-based or pre-dispatch-based demand response dispatches driven by system-wide shortages can be incorporated into the real-time market price and the HOEP. After Market Renewal, this would further extend to include any demand response dispatches driven by day-ahead conditions, zone-level congestion, and node-level congestion. Achieving this outcome will be challenging given the unique dispatch timeframes and characteristics of individual demand response resources that may prevent full incorporation into real-time security-constrained economic dispatch (SCED), but other markets such as PJM have adopted reasonable approaches.[94] Allowing for participation in the day-ahead market is important because, just like certain generating resources that are dispatched mostly on a day-ahead basis, not all DR resources will be able to respond to real-time dispatch signals.

- **Increase energy market price cap and adjust ancillary service shortage pricing consistent with the value of lost load (VOLL) for involuntary curtailments**.[95] Today, many demand response players in Ontario (and elsewhere) offer into the energy market at just below the maximum allowed offer price of $2,000/MWh. It is likely that at least some of the cap-based offers indicate that customers value their energy consumption at a price that exceeds the current price cap.[96] We recommend increasing the energy market price cap and adjusting ancillary service market scarcity pricing parameters to levels that are consistent with realistic estimates of VOLL in Ontario. For example, Texas uses a value of USD $9,000/MWh (CAD $11,898)[97] and the MISO market monitor recommended that scarcity prices should be able to reach a VOLL of USD $12,000. Allowing scarcity prices to reach these levels will ensure that reliability is not undervalued and that demand response can be induced to address reliability problems before they require involuntary load shedding. Because these shortage and near-shortage events are rare, increasing the price cap would have a negligible effect on average wholesale prices; however, proper pricing during such events would offer significant benefits by inducing more efficient system operations and investments.

Adopting these recommendations could address some current challenges to the full and efficient integration of demand response into Ontario's energy market. Ontario has the potential to develop increasing quantities of demand response using technologies and business models that are emerging or may not exist today. Implementing these recommendations would help integrate the demand resources

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94 *See* ISO market manuals for a discussion of demand response scheduling in energy markets.

PJM, "PJM Manual 11: Energy & Ancillary Services Market Operations," December 3, 2019 at 124.

MISO, "Business Practice Manual 2," 2018 at 58.

ISO-NE, "ISO-New England Manual for Market Operations," Manual M-11, April 7, 2017 at 2-9.

95 Maintaining a price cap equal to the value of lost load during scarcity events will provide efficient signals for generators and demand response participation.

Samuel A. Newell *et al.*, "Estimating the Economically Optimal Reserve Margin in ERCOT," January 31, 2014.

Johannes P. Pfeifenberger and Kathleen Spees, "Evaluation of Market Fundamentals and Challenges to Long-Term System Adequacy in Alberta's Electricity Market," April 2011.

96 Bids at the cap may be due to reason other than high curtailment costs, such as attempts to attract a high CMSC payment when curtailed or as a means of avoiding risks associated with a dispatch performance penalties.

97 "2018 State of the Market Report for the ERCO Electricity Markets," Potomac Economics, June 2019 at 19.

that exist today more effectively, and increase the market's flexibility to evolve with economic conditions and technological progress. Taken together, these recommendations would help to create a market and regulatory environment that would further foster the efficient development of the technologies and business models.

VI. List of Acronyms

AEMC	Australian Energy Market Commission
AMPCO	Association of Major Power Consumers in Ontario
CBDR	Capacity Based Demand Response
CLR	Controllable Load Resources
CMSC	Congestion Management Settlement Credits
DALR	Day-Ahead Load-Response
DAM	Day-Ahead Market
DER	Distributed Energy Resource
DR	Demand Response
DRA	Demand Response Auction
DRWG	Demand Response Working Group
DSO	Distribution System Operator
ERCOT	Electricity Reliability Council of Texas
ERUC	Enhanced Reliability Unit Commitment
ETNO	Energy Transformation Network of Ontario
EV	Electric Vehicle
FERC	(U.S.) Federal Energy Regulatory Commission
GA	Global Adjustment
HDR	Hourly Demand Resources
HOEP	Hourly Ontario Energy Price
ICI	Industrial Conservation Initiative
IESO	Independent Electricity System Operator
ISO-NE	Independent System Operator of New England
ISO	Independent System Operator
LDC	Local Distribution Company
LMP	Locational Marginal Price
LSE	Load Serving Entity
LSSi	Load Shed Service for Imports
MCP	Market Clearing Price

MRP	Market Renewal Program
OEB	Ontario Energy Board
OPA	Ontario Power Authority
PD	Pre-Dispatch
PJM	Pennsylvania-New Jersey-Maryland Interconnection (now serving 14 U.S. states)
PRD	Price Responsive Demand
RPP	Regulated Price Plan
RTPR	Real-Time Price Response
RTO	Regional Transmission Organization
SBG	Surplus Baseline Generation
SCED	Security-Constrained Economic Dispatch
SSM	Single Schedule Market
TPRD	Transitional Price-Responsive Demand
VOLL	Value of Lost Load
4CP	Four Coincident Peak

VII. Appendix

A. DEMAND RESPONSE PARTICIPATION IN THE IESO TODAY AND AFTER MARKET RENEWAL

TABLE 9: HOW DEMAND RESPONSE WITH A CAPACITY OBLIGATION PARTICIPATES IN THE IESO MARKET TODAY AND AFTER MARKET RENEWAL

	Dispatchable Load (DL)	Physical Hourly Demand Response (HDR)	Virtual Hourly Demand Response (HDR for C&I)	Virtual Residential HDR
Description	IESO Physical Market Participant; can be directly connected to the Tx system or connected to the Dx system	Contributors to a physical HDR are IESO Market Participants (non-Dispatchable Load) Can be directly connected to the Tx system or connected to the Dx system	Can include a mix of IESO market participants (Non-Dispatchable Load) can be directly connected or Dx connected), LDC customers	LDC customers
Metering	IESO Revenue metering with operational telemetry	Contributors are settled by IESO Revenue Metering	Predominantly LDC metered (although could include some IESO metered loads participating in a virtual portfolio) and across multiple LDCs in a region	LDC metered, but could be across multiple LDCs in a region
Aggregated?	No	One physical demand response capacity obligation can have more than one physical HDR resource registered to fulfill the obligation	Yes on a regional basis (can include any kinds of customers except Dispatchable Load), contributors can change on a monthly basis	Yes on a regional basis but must include 'control group' and 'treatment' contributors. Contributors can change on a monthly basis
Bids	Submit bids based on willingness to consume (must be greater than $100/MWh)	Submit bids based on willingness to consume (must be greater than $100 /MWh)	Can submit one bid per zone (must be greater than $100/ MWh)	Can submit one bid per zone (must be greater than $100/ MWh)
Energy Settlement	Energy settled by IESO on 5-minute MCP Market Schedule Settled and evaluated on Actual Consumption when 'activated'	No energy settlement; contributors are settled by IESO on hourly HOEP. Evaluated on 'baseline' consumption when activated (high 15 of 20 bus days with in-day adjustment)	No energy settlement with resource. Individual contributors may be settled on HOEP, RPP, Retail, etc. Evaluated on 'baseline' consumption when activated (high 15 of 20 bus days with in-day adjustment) on total aggregated load not individual contributor performance	No energy settlement with resource. Evaluated on residential baseline (looking at difference of behavior between control group and treatment group)

	Dispatchable Load (DL)	Physical Hourly Demand Response (HDR)	Virtual Hourly Demand Response (HDR for C&I)	Virtual Residential HDR
GA	Class A or Class B	Class A or Class B	Class A or Class B, RPP or a mixture	RPP or Retail
Dispatch	Security constrained dispatch every 5 minutes. Must following dispatch schedule (to curtail or consume)	Put on standby if shadow price in PD at location is greater than $200/MWh by 0700 of the dispatch day. If put on standby, evaluated in dispatch. If not, no further obligation for the day. Activated when shadow price at location is greater than bid price in PD-3. Outside of activation, no requirement to consume or curtail on the basis of bids (no dispatch)	Put on standby if shadow price at location is greater than $200/MWh by 0700 of the dispatch day. If put on standby, evaluated in dispatch. If not, no further obligation for the day. Activated when shadow price at location is greater than bid price. Outside of activation, no requirement to consume or curtail on the basis of bids (no dispatch)	Put on standby if shadow price at location is greater than $200/MWh by 0700 of the dispatch day. If put on standby, evaluated in dispatch. If not, no further obligation for the day. Activated when shadow price at location is greater than bid price. Outside of activation, no requirement to consume or curtail on the basis of bids (no dispatch)
Make-Whole	Entitled to bid guarantee payments when dispatch schedule different than market schedule. CMSC returns them to the operating profit implied by their market schedule	No make-whole. Physical contributors settled on uniform HOEP	No make-whole. No energy settlement with resource. No interaction with contributors	No make-whole. No energy settlement with resource. No interaction with contributors
Today	Incented to follow dispatch efficiently	May be exposed to instances of curtailment where HOEP prices lower than bid prices	Aggregation of different load types (RPP, HOEP, Class A, B, retail). Disconnect between uniform price and 'dispatch price', disconnect between RPP and dispatch price.	Must be residential customers only
Market Renewal	Still incented to follow dispatch but now market and dispatch schedules will be the same	Still disconnect between future uniform or zonal price and basis for dispatch	Still disconnect between future uniform prices and basis for dispatch	Still disconnect between future uniform prices and basis for dispatch

B. CALCULATION OF A CUSTOMER BENEFITS TEST IN ONTARIO

In Section 1 of this report, we discussed why a customer benefits approach similar to that adopted under FERC 745 is inconsistent with a competitive electricity market, and why we do not recommend this payment option for Ontario. However, we understand that this approach has been extensively discussed in Ontario. Therefore, in this appendix we elaborate further the details of how such a net benefits test could be adapted into the Ontario context and to provide an illustrative example implementing such a test. We provide this calculation at an illustrative wholesale market price under a self-consistent set of assumptions. The same calculation could be implemented across a range of prices to determine the wholesale price above which customers earn a net benefit from energy price reduction that exceeds the cost of paying the demand response asset to curtail. The threshold price calculation in Ontario would conceptually be modeled after the FERC Order 745 approach, but would need to adapt to the Ontario context. The primary difference an Ontario net benefits test would have is the accounting of the Global Adjustment charge (though other more nuanced differences also exist for adapting to the Ontario context).

1. A Method for Implementing a Customer Benefits Calculation in Ontario

To implement the customer benefits approach in Ontario, the system operator would periodically conduct an estimate of the threshold price above which demand response dispatches are anticipated to yield net customer benefit. This likely could be done on a monthly basis based on anticipated market conditions for the upcoming months. The system operator would need to build an average market supply curve using supply offers for the reference timeframe and use that supply curve to estimate the energy price reduction and avoided uplift charges that would be achieved through demand response activation at each price level (less the costs of DR payments and any offsetting Global Adjustment charges). Once calculated, the threshold price would determine the minimum price at which demand response resources would be eligible for payments at the full wholesale price. To determine the threshold price, the system operator would estimate net customer benefits at different price levels, until identifying the minimum price above which customer benefits exceed customer costs.

The net customer benefit would be calculated as shown in the following formula and in the following **Table 10**.

THE NET CUSTOMER BENEFIT

Net Customer Benefit = Energy Price Reduction

+ Decrease in Make-Whole Payments

– Payments to Demand Response

– Increase in Global Adjustment

The terms of the customer benefit calculation would be:

- **Energy price reduction.** Demand response curtailment results in lower demand for electricity, which in turn reduces the energy price. Price reduction is the difference in prices due to the activation of demand response. This price reduction (in $/MWh) would be multiplied by the total consumption of Ontario customers in order to arrive at a total Ontario-wide estimate of customer price reduction benefits. Customer price reduction would be calculated separately for Class A and Class B customers based on hourly consumption, and may or may not be calculated as a total across all customer classes. Demand for exports would not be considered in the estimate of benefits to Ontario customers.
- **Decreases in System-Wide Make-Whole Payments.** Demand response activation may or may not also result in a decrease (or increase) of other system-wide make-whole payments to all energy market participants. These make-whole payments could include Congestion Management Settlement Credit (CMSC), Intertie Offer Guarantee, and Generator Cost Guarantee. Other than CMSC, we anticipate the difference in uplift costs to be relatively small compared to the other terms in this calculation. Further, though it may be possible to calculate these payment changes in any one real-world instance of activation, they would likely to be challenging to estimate in any meaningful way for a "typical" activation that may be pursued over the month.
- **Payments to Demand Response Resources.** For reducing consumption, demand response participants would receive energy market payments as compensation. Payments would be equal to the after-activation wholesale electricity price (in $/MWh) multiplied by the curtailment quantity (in MWh).
- **Increases in Global Adjustment.** Lower wholesale electricity prices due to demand response activation means that less of the total cost of contracted and regulated resources would be recovered through energy market revenue. Consequently, more costs would recovered through the Global Adjustment. Again, the impact of Global Adjustment to offset customer benefits would be calculated separately for Class A and Class B customers, and may or may not be assessed in total across all customers.

TABLE 10: COMPONENTS OF AN ONTARIO NET CUSTOMER BENEFITS TEST FOR DEMAND RESPONSE ACTIVATIONS

Impact	Customer Benefit (or Cost)	Description	Calculation
+	**Energy Price Reduction**	Price reductions occurs when demand response curtailment reduces the $/MWh energy price. Customer price reduction would be calculated separately for each class of customer based on hourly consumption and/or in total across all customer classes (export demand would not be considered)	(Price *Before DR* – Price *After DR*) × Final Market-Wide Customer Demand
+	**Decreases in System-Wide Make-Whole Payments**	The decrease (or increase) of other system-wide make-whole payments to all energy market participants. Other than CMSC, we anticipate the difference in uplift costs to be relatively small compared to the other components	(CMSC + IOG + GCG + Other Uplifts) *Before DR* – (CMSC + IOG + GCG + Other Uplifts) *After DR*
–	**Payments to Demand Response Resources**	Energy market payments made to demand response participants as compensation for reducing consumption	Wholesale Price × Curtailed DR MWh
–	**Increases in Global Adjustment**	Less of the total cost of contracted and regulated generators is recovered through energy market revenue, so more costs are recovered through the Global Adjustment. Class B customers pay a larger share of the total GA than Class A customers, so the offsetting effect of GA cost increases will affect them more relative to Class A customers	Contract & Regulated Resource Payments *After DR* – Contract & Regulated Resource Payments *Before DR*
=	**Net Customer Benefit**		

Notes and sources:

— CMSC = Congestion Management Settlement Credit

— IOG = Intertie Offer Guarantee

— GCG = Generator Cost Guarantee

2. Illustrative Calculation of a Customer Benefits Threshold Price

We provide here an indicative, order-of-magnitude calculation of the customer benefits threshold in Ontario based on an indicative but self-consistent set of assumptions. The most important of these assumptions are the size of energy price reduction (as driven by the slope of the energy market supply curve) and the share of market supply under contract and so contributing the Global Adjustment offset. We conduct this simplified illustrative calculation on a system-wide basis, without considering import/export offers and without considering uplift payment impacts. We account only for the largest components of the customer benefits calculation including: wholesale price reduction of the HOEP, demand response payments at the HOEP, and increases by the Global Adjustment. If implemented in

Ontario, the calculation would likely need to be refined to account for locational pricing impacts (including CMSC payments prior to Market Renewal and locational marginal pricing after Market Renewal), uplifts, and other granular details that may affect resulting customer impacts. Consistent with U.S. practice, the calculation could be updated on a monthly basis in consideration of anticipated market conditions.

To estimate energy price reduction, one would begin with a “typical” supply curve that is anticipated to reflect Ontario energy market conditions in the coming month. We understand from IESO staff that developing such a “typical” supply curve may be a material challenge in Ontario given the province’s unique supply mix of significant proportion of variable, intermittent and energy-limited resources, whose availability can vary on a daily and even hourly basis.[98] With this typical curve, the slope in energy prices ($/MWh per MW of demand response activation) can be determined at each price and associated quantity level. This can be translated into the total price reduction by multiplying by the final energy demand after apply 1 MW of demand response activation. For the purposes of our illustrative calculation, we assume that at a price of $110/MWh pre-activation price, a 1 MW demand response activation would achieve a $0.10/MWh reduction to Ontario-wide prices.

The other components of the energy market benefits test calculations are summarized in **Table 11** at the same illustrative price point of $110/MWh, with customer impacts calculated separately for Class A and Class B Customers.[99] Not accounting for Global Adjustment payment impacts, demand response activation would lead to a benefit of $2,500 thanks to price reduction. Accounting for the $2,200 in increased Global Adjustment payments and the $110 in demand response payments, the net customer *benefit* is $190. Looking separately by customer class, we find that Class A customers would realize a net benefit of $297 from demand response activations at this price level, owing to the lower total share of Global Adjustment charges paid by Class A customers. However, Class B customers would not realize a net benefit due to the large share of total Global Adjustment costs paid by Class B customers compared to their share of hourly load. Put differently, Class B customers would pay more than they would without demand response activation.[100]

98 We have not attempted to develop such a curve based on any review of Ontario offer curves and so do not offer any additional comments on an appropriate methodology that could be used to reliably develop this estimated supply curve for each month.

99 The Global Adjustment charge is billed to customers in two different methodologies depending on whether a customer falls into the Class A or Class B category. Class A customers (typically large customers with high levels of consumption) are charged based on their consumption during the five peak hours of the year. The total Global Adjustment cost to the province for the year is shared among Class A consumers based on their share of consumption during the peak hours. This amounts to about $100,000 per MW consumed during the five peak hours. Class B customers are charged the remaining Global Adjustment balance on a volumetric basis. They are billed at a constant monthly rate based on consumption in that period.

100 Class A and Class B hourly load share assumed at 29% and 71% and annual GA share assumed at 18% and 82% respectively, per the 2019 Global Adjustment Component and Costs Report average. Since the Class A load profile is typically flatter, it will have a lower load share at higher prices and a higher load share at lower prices. This example may overstate the disproportionate Class B negative impact since Class B’s higher load share at higher prices will result in a higher proportion of attributed benefits than shown in the example.

TABLE 11: ILLUSTRATIVE CALCULATION OF NET CUSTOMER BENEFITS FROM A 1 MW DEMAND RESPONSE ACTIVATION

			CUSTOMER BENEFIT		
	Customer Benefits	**Calculation**	**Class A**	**Class B**	**Total**
+	Customer Price Reduction	**(Price Reduction) x Final Customer Demand**	**$725**	**$1,775**	$2,500
–	Payments to Demand Response Resources	**Final Wholesale Price x Quantity of DR Curtailed**	**$32**	**$78**	$110
–	Increases in Global Adjustment Costs	**GA Payments *After DR* – GA Payments *Before DR***	**$396**	**$1,804**	$2,200
=	Net Customer Benefit	**Price Reduction – DR Payments – GA Increases**	**$297**	**–$107**	$190

Notes and sources: Assuming 15 GW of fixed-contract or regulated supply, 7,000 MW of deeming contract supply, 3,000 MW of non-price-dependent GA contracts or supply not reliant on GA payments.

3. Drivers of the Scale of Global Adjustment Offsets

The Global Adjustment component in the customer net benefit will offset the energy price reduction as described in **Table 12** below. The nature of most Ontario supply contracts and rate regulation is to keep suppliers whole to a specific contract payment or rate regardless of the wholesale energy price. Fixed-price, clean energy supply (CES), and rate regulated rate payments establish the revenue that each resource will earn. When energy prices are below the stipulated payments, the Global Adjustment is used to make the seller whole to the stipulated rate; when energy prices exceed the stipulated payments (as they typically will during high-priced hours when DR is called), the seller must “pay back” the excess to the customer, which reduces the Global Adjustment. When prices are reduced through a DR activation at high-priced hours, this means that the “payback” from contracted resources is also reduced thus leaving customers no better off due to the price reduction.

If all supply resources in Ontario were paid under such a contract structure, then the GA offset costs would exactly equal energy price reduction benefits, leaving customers as a whole entirely indifferent as to wholesale prices or the level of price reduction achieved. However, during high-priced hours when DR activations are typically called, customer price reduction benefits will tend to exceed the Global Adjustment offset because there may be a portion of total supply from imports and other resources that are not contracted, regulated, or guaranteed a stipulated price and, thus, do not have an offsetting effect to the price reduction. If the Ontario market reduces the share of resources under contract over time, the size of this offset will also decline.

TABLE 12: ILLUSTRATIVE IMPACT ON GLOBAL ADJUSTMENT FROM DIFFERENT SUPPLY TYPES

	Contract Type	GA "Payback" *Before DR* Activation	GA "Payback" *After DR* Activation	GA Increase w/ 0.10/MWh Price Reduction
Supply Contributing to Global Adjustment Offset	**Rate-Regulated Supply & Fixed Price Contracts** Assume $60/MWh price	$50/MWh = $110 – $60	$49.90/MWh = $109.90 – $60	$0.10 1-to-1 GA vs. Energy Price Offset
	Clean Energy Supply Contracts Assume price exceeds deemed dispatch price of $30/MWh	Deemed Profit $80/MWh = $110 - $30	GA Reduced by Deemed Profit $79.90/MWh = $109.90 - $30	$0.10 1-to-1 GA vs. Energy Price Offset
Supply *Not* Contributing to Global Adjustment Offset	**Lennox** Capacity-Only Contract Structure	$0 Capacity payments only	$0 Capacity payments do not depend on energy price	$0 No GA Offset
	Resources with No Contract or Expired Contracts May Earn Capacity Auction Payments	$0 No payments or capacity payments only	$0 Capacity payments do not depend on energy price	$0 No GA Offset
	Imports No Contracts	$0 Energy payments only, no GA	$0 Energy payments only, no GA	$0 No GA Offset

4. Takeaways and Challenges in Adapting a Customer Benefits Test to the Ontario Context

Directly applying the FERC 745 net customer benefits test to the Ontario context requires addressing various unique economic conditions in the province. Energy price reduction benefits could be calculated similarly to how this is done in U.S. markets, but would need to account for the factors that make it more challenging to develop a "typical" supply curve in Ontario. Namely, significant variability in the prices and quantities of hydro, wind, and import resources would make it more challenging to develop a supply curve that can be assumed to apply across most market conditions for a month. Thus this may require conducting analyses across an uncertainty range of supply curves and accepting a greater level of imprecision in estimating the threshold price above which customer benefits would exceed customer costs.

The implications of the Global Adjustment charge and associated offsets to customer benefits are an even more important factor to consider. To first order, because Ontario is essentially a fully contracted and hedged market, the Global Adjustment will tend to largely offset any customer benefits that would be achieved through price reduction. In high-priced hours when a more material share of energy is supplied by imports and resources earning only capacity payments, this offset is less than one-to-one such that customers would be expected to earn a net benefit from price reductions. The threshold price above which net customer benefits would be achieved is higher than it would be in a market without such contracts. However, if the province becomes less contracted over time, then the threshold price at which customers earn net benefits would come down.

Another important feature of the Global Adjustment is the distinct and potentially divergent impacts on Class A versus Class B customers. Because Class A customers pay a lower share of the total Global Adjustment (18% as of 2019), the offsetting effect of Global Adjustment cost increases will affect them less. The majority of the Global Adjustment is recovered from Class B customers, who would bear a greater share of any increases to the Global Adjustment. This means that there are many cases when Class A customers could benefit from DR activations, while Class B customers would be harmed. This raises an equity concern if a customer benefits test were applied based on a grouping of all customers together, since some but not all customers would share in the anticipated benefits.

More fundamentally, and as we have discussed in earlier sections of this report, we do not recommend adopting a customer benefits framework to establish a means of incorporating demand response into the energy market. An approach that is based on maximizing societal benefits is more consistent with the context of a competitive electricity market, and so we recommend considering one of the alternative approaches discussed above—either "Wholesale Price minus G" or "Retail Purchase and Wholesale Sellback"—in which demand response participants that are not currently exposed to the full wholesale market price would be incentivized to respond based on marginal system value