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POLICY BRIEF
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Don't leave me stranded: What to do with Ontario's Global Adjustment?

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EXECUTIVE SUMMARY

- This Policy Brief offers an economic perspective to the ongoing policy discussions around the global adjustment. The global adjustment is a monthly fee paid by Ontario consumers to cover the fixed cost to build and maintain generation assets in the province, and to deliver Ontario's conservation programs. It embeds costs incurred to achieve various social policy objectives, including: maintaining supply reliability, promoting environmental and health benefits, and developing green industries and green jobs. The global adjustment is the largest component of the average consumer's electricity cost, representing between 45 to 60 percent of the total electricity bill.

- The current method used to recover the global adjustment from Ontario consumers—the Industrial Conservation Initiative—provides an extreme price incentive for some large consumers to reduce their demand during system peak demand hours. In some cases, it has induced large consumers to invest in storage or behind-the-meter generation to bypass the cost of consuming grid supplied electricity. This bypass can lead to an inefficient use of the province's generation, transmission and distribution assets and increase the risk of the eventual stranding of the province's large grid-related assets.

- This Policy Brief offers a practical approach for decomposing the global adjustment into three separate components: capacity costs, an energy price hedge, and system-wide fixed costs. It proposes that for efficiency and equity reasons, each component should be recovered as a separate charge, and a different cost recovery method should be applied to each component. Doing so, would reduce the risk of hastening investment in new distributed solutions, the stranding of current grid assets, and higher overall costs for Ontario's electricity consumers.

INTRODUCTION

Ontario is evolving its electricity pricing polices in the midst of a changing technological landscape, and the two spheres are path dependent. How the province evolves its pricing policies could materially influence the pace at which consumers adopt new distributed energy technologies as a substitute for receiving traditional grid-related services.

From a policy perspective, the Independent Electricity System Operator (IESO) is working with stakeholders to reform the design of Ontario's competitive wholesale electricity market. The goal of the reform is to "improve the way electricity is priced, scheduled and procured in order to meet Ontario's current and future energy needs reliably, transparently, efficiently and at lowest cost."[1] The Ontario Energy Board (OEB) is seeking to modernize the design of distribution and regulated retail rates in the face of an evolving sector, to promote the efficient and equitable recovery of system costs that are largely fixed and sunk, and to facilitate the rational adoption of new technologies.[2] More recently, the Ontario government held consultations with Ontario businesses to hear first-hand about industrial electricity pricing and programs, and their ideas on how the province's electricity system can make business more competitive.[3]

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

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

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

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

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

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

BACKGROUND ON THE GLOBAL ADJUSMENT AND INDUSTRIAL CONSERVATION INITIATIVE

Global Adjustment

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

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

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

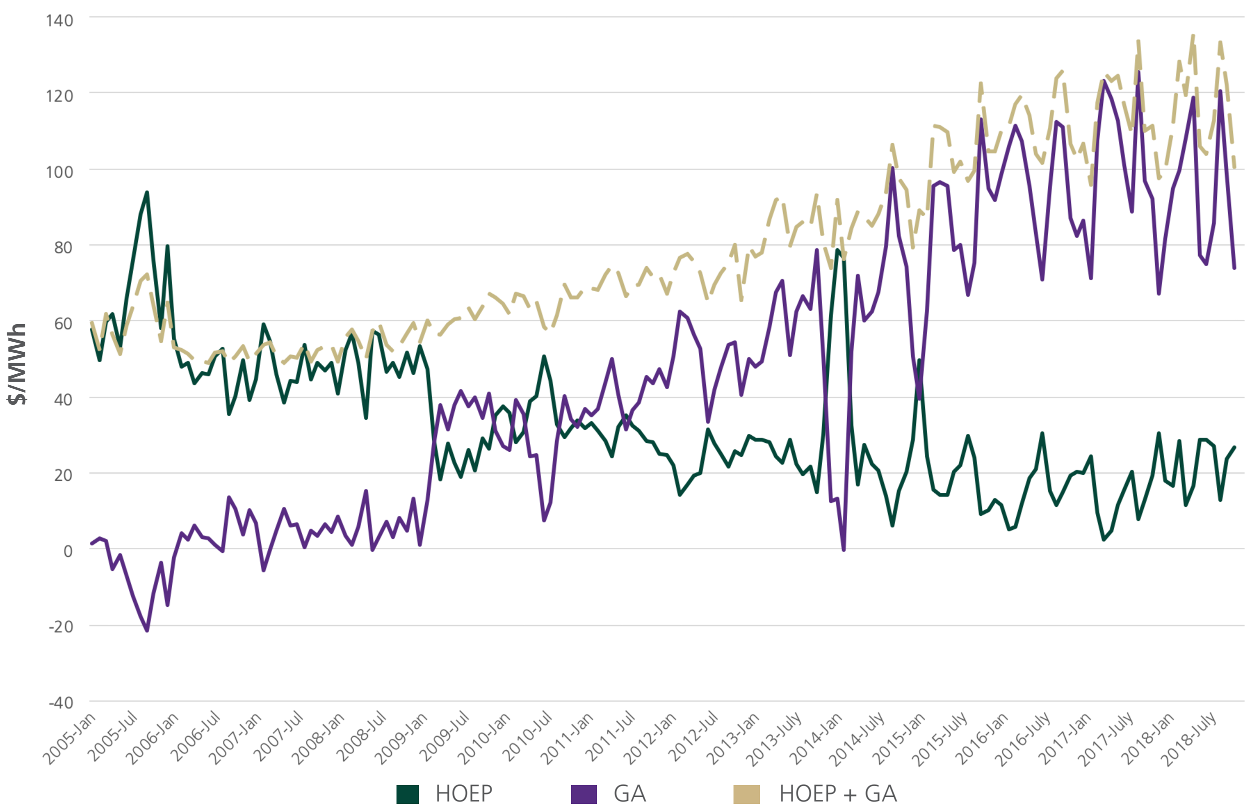
- reconcile differences between payments made to generators at the competitive wholesale market price and payments made through regulation or contract that differ from the wholesale market price; and
- fund the province's conservation and demand management programs.

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

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

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

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



Source: Author created from data available from the IESO.

Industrial Conservation Initiative

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

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

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

ISSUES WITH THE GLOBAL ADJUSTMENT AND GENERATION COST PRICING

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

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

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

Insert 1 | Glossary of Economic Terms

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

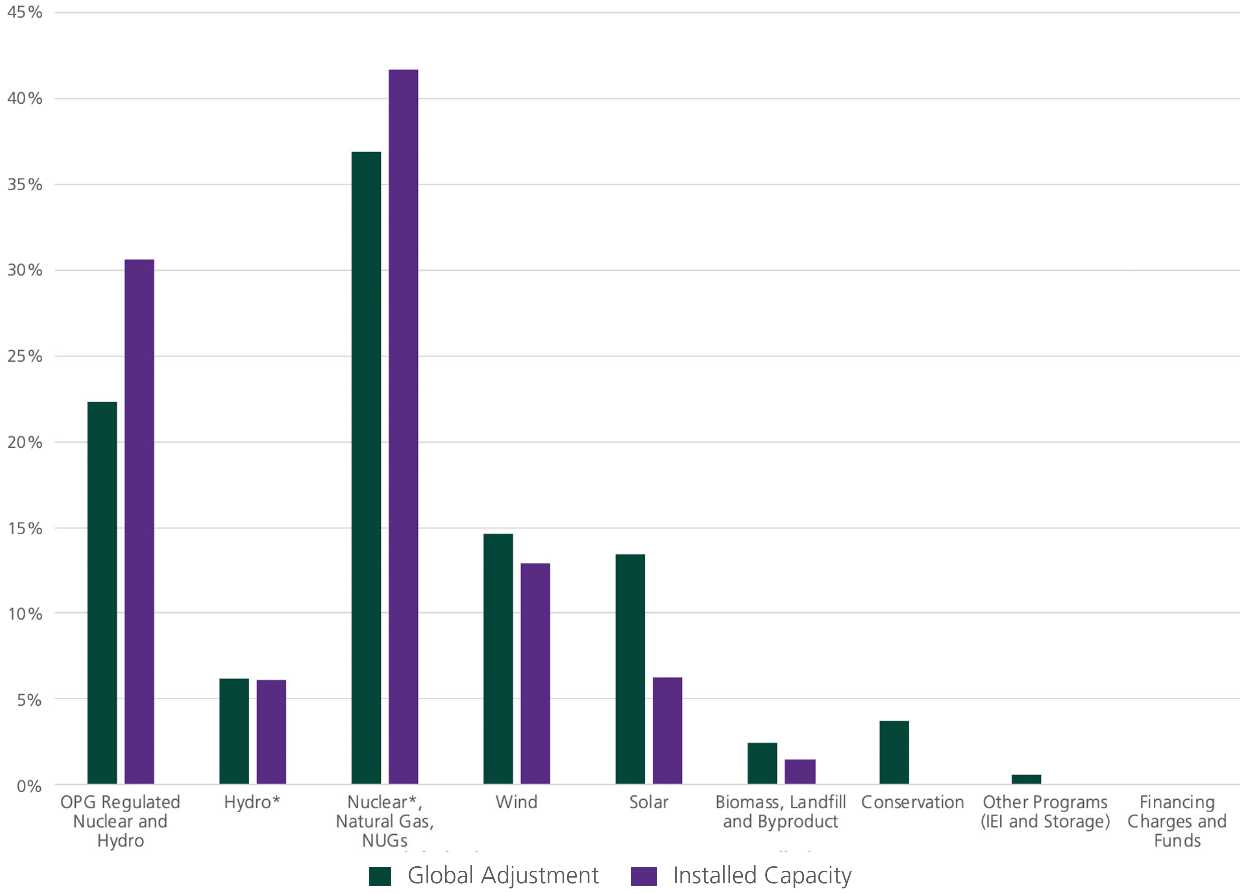
Fixed costs: Costs that do not vary with the quantity of output produced.

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

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

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

Figure 2 | Share of Global Adjustment and Share of Total Capacity by Generation Technologies, 2017



* Non-OPG assets

Source: Author created from data available from the IESO.

A second concern around the global adjustment relates to how the province prices and allocates its generation costs. For example, the OEB's Market Surveillance Panel (MSP) has argued that the current approach leads to an inefficient and inequitable allocation of generation costs.[15] The ICI provides Class A consumers with an extreme incentive to invest in behind-the-meter generation and storage to avoid paying the global adjustment.The cost of these investments are generally higher than the actual avoided cost of using grid supplied electricity, which makes the investments socially inefficient. Furthermore, as Class A consumers build on-site generation or storage and reduce overall grid level consumption, the sunk global adjustment costs are shifted to other consumers. This cost shift induces more consumers to find ways to avoid paying the global adjustment, including investing in distributed energy solutions. The MSP warns that this cycle could eventually lead to the premature stranding of large grid assets, and higher costs for Ontario consumers overall.

Unlike the concerns related to the size and nature of costs within the global adjustment, there are opportunities to redress the decision on how the province's generation costs are allocated to consumers to promote more efficient and equitable outcomes. This is the intended contribution of this Policy Brief and the focus of the next section. The remainder of this section sets out economic principles for efficient and equitable pricing and evaluates the current Ontario approach against these principles.

An Economic Perspective on Efficient and Equitable Pricing

In economics, a market is efficient in the short-term if it makes best use of the presently available productive assets. This occurs when the commodity is produced by the cheapest suppliers and it is consumed by all consumers and only those consumers whose willingness to pay to consume is no less than the cost of all inputs used to make it. Long-term efficiency is about making optimal and timely decisions on the investment in new assets and the maintenance or expiry of existing assets. In the long-term, efficiency is achieved when the industry produces at the point where industry long-term average cost is minimized.

Standard microeconomic analysis clearly establishes that economic efficiency is maximized in the short-term when prices equal the marginal cost of production;[16] any departure from marginal cost pricing is likely to reduce the economic value the industry can create.[17] The exception to this rule is when there is a constraint on productive capacity. In this case, price must exceed the marginal cost of the last MW produced in order to ration demand. Efficient pricing with short-term capacity constraints requires the demand side of the market to set the price. The price equals the dollar value of the benefit consumers would get from consuming one more MW of electricity (i.e. the marginal willingness to pay). This price represents the marginal value of adding one MW of new capacity. In the energy economics literature, the portion of the peak price that is above marginal cost is called a *scarcity rent*.[18] Scarcity rents provide producers with an opportunity to cover a portion of their fixed cost. They also provide a signal to potential investors of the relative scarcity of capacity, and the value of either retiring existing capacity or investing in new capacity. Scarcity rents provide incentives for efficient long-term investment decisions. In the long-term, scarcity rents equal the marginal cost of adding new capacity.[19]

There are instances, however, when short-term marginal cost pricing fails to provide producers with sufficient revenue to recover all of their costs, particularly the fixed costs to build and maintain their productive assets. This can be true of industries that require investment in specialized assets with significant fixed costs (i.e. natural monopoly industries). Transmission and distribution services are standard examples of such an industry. Governments generally prefer regulation to competition in these industries, and the challenge for the regulator is to design consumer prices or rates that balance the goals of efficiency and consumer fairness or equity, but allow the regulated firm to recover all of the fixed costs to build and operate the assets, plus earn a fair rate of return on capital (financial viability).

In the regulatory arena, consumer fairness or equity is generally discussed in terms of cost causality (i.e., prices should be fair, in the sense of assigning costs to those who cause them and/or benefit from them being incurred).[20] This concept raises an important distinction between the recovery of fixed costs that are customer-specific versus those that are system-wide.[21] Customer-specific fixed costs vary according to whether the customer receives service from the regulated firm, but not in terms of how much electricity the customer consumes. For example, costs related to account set-up with a distribution company such as meter-related capital costs, minimum service drop costs, and final line transformer expenses are customer-specific. System-wide fixed costs cannot be attributable to a specific customer and are independent of how much electricity is consumed on the system. These can include construction and maintenance cost of a transmission or distribution system or public purpose programs such as conservation and energy efficiency programs. It is both efficient and fair from a cost causality perspective to recover customer-specific fixed costs directly from consumers as a fixed charge. It is the recovery of system-wide fixed costs that involves trade-offs between efficiency and equity. The trade-off generally requires a value judgement on the preferred distribution of wealth.[22]

There is an extensive theoretical and applied literature on approaches for the design of efficient and equitable rates to cover a utility's system-wide fixed costs.[23] Borenstein (2016) examines several approaches and notes that each has pros and cons (See Insert 2 for Bornstein's evaluation). Borenstein concludes that there is no ideal pricing policy, although balancing efficiency and equity suggests using a combination of fixed charges and increased volumetric prices above marginal cost.

Insert 2 | Regulatory Approaches to Utility Fixed Cost Recovery

Volumetric average cost pricing:
A charge per kilowatt hour (kWh) consumed equal to the utility's average total cost. Often seen as fair, since all consumers are treated the same; yet it is inefficient, as it induces too much consumption when the average price is below marginal cost (typically during peak demand periods) and too little consumption when average price is above marginal cost (typically during low demand periods).

Ramsey pricing:
Charging different prices to different consumers based on their elasticity of demand. Efficient in a second-best sense, but generally impractical to implement, as it requires detailed information on individual consumer's demand elasticities. It is sometimes considered "unfair," as low-income consumers typically have the most inelastic demand and pay higher prices.

Fixed charges:
A set amount that does not vary with the volume of electricity used. A volumetric charge for the commodity equal to marginal cost, plus a fixed charge based on willingness and ability to pay, promotes first-best efficiency if there is perfect information on each consumer's willingness to pay. However, in practice, information is imperfect and finding an appropriate proxy measure for willingness and ability to pay has proven challenging, particularly for large industrial and commercial consumers.

Demand charges:
A charge per kWh based on a consumer's peak demand during a defined billing period. There is no efficiency or equity basis for using demand charges to recover system-wide fixed costs as there is no direct relationship between a customer's peak demand levels and these costs.

An Evaluation of Generation Cost Pricing in Ontario

Generation costs include the marginal and variable costs to produce electrical energy and the fixed costs to build and maintain generation capacity. In Ontario, generators recover their variable costs (and part of their fixed costs) in the wholesale market through the competitive market clearing price, which is designed to reflect the system marginal cost at any point in time.[24] Generators are assured their fixed costs are recovered through contracts with the IESO or in the case of OPG, through regulated rates. Payment of these costs are reflected in the global adjustment.

As Figure 1 illustrates, the global adjustment has grown to be 4 to 5 times larger than the market price (i.e., marginal cost), demonstrating that generation cost recovery based on marginal cost pricing alone would result in a revenue shortfall for some if not all generators. Therefore, an alternative regulatory pricing approach, such as those examined by Borenstein (2016), must be considered.[25]

Efficient and equitable fixed cost recovery in Ontario represents a particular challenge because the global adjustment includes both customer-specific fixed costs, system-wide fixed costs and an energy price hedge. Some of the fixed costs in the global adjustment were incurred to ensure a reliable level of generation capacity. Generation capacity costs are essentially a customer-specific cost in that individuals that consume energy in the hours when the IESO projects capacity is most needed for reliability (i.e., system-peak demand periods) contribute to the need for and cost to build and maintain generation capacity. Historically, "dumb" meters did not permit measurement of individual consumer demand during these system peak hours. However, smart meters now provide an accurate hourly measure of the amount any individual consumes, allowing for more direct recovery of customer-specific capacity cost. Other fixed costs in the global adjustment were incurred to promote environmental and health objectives related to the reduction of greenhouse gases, and for economic objectives related to the development of green industries and green jobs. These costs were incurred for the benefit of all Ontarians and they cannot be attributed to any specific consumer (i.e., a system-wide fixed cost). Furthermore, a portion of the payments to OPG's regulated assets reflect the 2005 policy goal of providing consumers price stability, again for the benefit of all Ontario consumers.

Table 1 | Generation Cost Pricing by Consumer Group

Customer Class	Energy Cost	Global Adjustment
Class A	HOEP or MCP* (Marginal Cost Pricing)	Share of 5 Coincident Peaks (Demand Charge)
Class B - RPP	Time-of-Use Prices (Time-Varying, Volumetric Pricing)	
Class B - Non-RPP	HOEP (Marginal Cost Pricing)	Class B GA rate (Volumetric Pricing)
Exports	MCP (Marginal Cost Pricing)	Do not pay

*A small number of large consumers that participate directly in the wholesale market (dispatchable loads) pay the 5-minute market-clearing price (MCP). The HOEP is equal to the arithmetic average of the hourly 5-minute prices.

As Table 1 illustrates, different approaches to generation cost recovery currently apply to different consumer groups. The following provides a brief evaluation of each approach against the principal criteria of efficiency and equity, using Bornstein's assessment as a guide.

In all hours, Class A consumers pay the marginal cost for the electricity that they consume. They are charged a portion of the global adjustment through a demand charge in the five coincident peak demand hours. This pricing approach encourages efficient consumption in the hours that a Class A consumer does not expect to be a coincident peak demand hour since they pay marginal cost. However, because the global adjustment includes both customer-specific fixed capacity costs and system-wide fixed costs, it can induce too little consumption in the expected coincident peak hours if the avoided global adjustment cost is greater than the marginal cost of adding new capacity or consumers' willingness to pay. The MSP recently estimated that a Class A consumer that reduced its demand by 1

MW in all 5 coincident peak demand hours in 2016, would have avoided an annual global adjustment fee of $520,000, which is considerably higher than the marginal cost of adding new generation capacity (the customer-specific cost) and well in excess of estimates of an average consumer's willingness to pay.[26]

Class B consumers are divided into Regulated Price Plan (RPP) consumers (low volume residential and small business consumers) and non-RPP consumers (larger businesses with monthly peak demand of more than 0.5 MW that are not Class A consumers). Non-RPP consumers pay marginal cost plus the Class B monthly global adjustment rate for each MW consumed in the month, which is a volumetric charge.[27] This pricing approach is inefficient in that it encourages too little consumption in all hours; it sets a price above marginal cost in all non-coincident peak hours, and a price above marginal cost plus the long-run marginal cost of new capacity in the coincident peak demand hours (as noted above for Class A consumers). RPP consumers pay time-of-use rates (on-peak, off-peak and mid-peak) set by the OEB, that embed the competitive energy price (HOEP) and the remaining Class B share of the global adjustment (i.e., a time-varying, volumetric pricing).[28] This pricing will induce inefficient consumption in virtually all hours as the time of use rates rarely if ever equal marginal cost or precisely reflect the marginal cost of adding new capacity in the coincident peak hours.

A third group of consumers, exporters, are OEB licensed companies that move electricity from Ontario to another jurisdiction for use by consumers in the other jurisdiction. Exports pay the 5-minute MCP for energy exported out of Ontario. Exporters do not pay the global adjustment. Similar to Class A consumers, this pricing approach encourages efficient consumption in the non-coincident peak hours. The efficiency of the approach in coincident peak hours is more difficult to assess and somewhat controversial for reasons discussed in the next section.

All approaches are questionable from an equity standpoint since they all essentially allocate the system-wide fixed cost in the global adjustment through a demand charge. Class A customers are allocated the system-wide costs directly through a five coincident peak demand charge, and Class B consumers are allocated these costs indirectly by being responsible for the residual of costs based on their aggregate consumption during these hours. As Borenstein notes, there is no relationship between a consumer's peak demands and system-wide fixed costs or the benefits from them being incurred. Hence allocating these costs results in an arbitrary and likely inequitable allocation.

Finally, the MSP argues that the avoided global adjustment fee of $520,000/MW creates an incentive for Class A consumers to invest in on-site generators or storage facilities that are likely more expensive to build and or operate than transmission-connected generation or demand response capacity. As a result, as Class A consumers build on-site generation or storage to reduce grid level consumption and avoid global adjustment, the sunk costs contained in the global adjustment are simply shifted to other consumers, particularly Class B consumers who currently do not have the same ability to avoid these costs. This cost shift induces more consumers to find ways to avoid paying the global adjustment, including investing in distributed energy solutions to avoid consuming from the grid. The MSP raises the concern that this cycle could eventually lead to the premature stranding of generation, transmission, and distribution costs, and higher costs for Ontario consumers overall.[29]

RECOMMENDATIONS FOR MORE EFFICIENT AND EQUITABLE PRICING

As outlined in the previous section, a key challenge for designing efficient and equitable approaches for the pricing of generation costs in Ontario is that the global adjustment embeds customer-specific and system-wide fixed costs and the energy price hedge on OPG's regulated assets. The first step towards improving generation cost pricing in Ontario is to decompose the global adjustment into these three component amounts. The second step is to price each component separately, using an approach that balances the principal criteria of efficiency and equity as outlined above.

Table 2 sets out a practical approach to the first step, decomposing the global adjustment into its three separate components, namely customer-specific capacity costs, the OPG energy price hedge, and system-wide fixed cost. Table 3 offers suggestions for the second step.

Table 2 | Contribution to Global Adjustment (2017)

GA Components	Global Adjustment (Millions)	Installed Capacity (MW)	Unforced Capacity (MW)	Capacity Price ($/MW-y)	Capacity Cost (Millions)	Energy Price Hedge (Millions)	System-Wide Costs (Millions)
OPG Regulated Nuclear and Hydro	$2,649	12,154	10,234	$125,925	$1,289	$1,360	$0
Hydro*	$731	2,433	1,721	$125,925	$217	NA	$514
Nuclear*, Natural Gas, NUGs	$4,375	16,554	15,363	$125,925	$1,935	NA	$2,440
Wind	$1,738	5,124	587	$125,925	$74	NA	$1,664
Solar	$1,594	2,470	826	$125,925	$104	NA	$1,490
Biomass, Landfill and Byproduct	$287	579	514	$125,925	$65	NA	$222
Other Programs (IEI and Storage)	$68	357	297	$125,925	$37	NA	$30
Conservation	$443	0	0	$125,925	NA	NA	$443
Financing Charges and Funds	-$33	0	0	$125,925	NA	NA	-$33
Total	**$11,851**	**39,670**	**29,543**		**$3,720**	**$1,360**	**$6,770**
Resource Reliability Requirement			27,689				
Surplus Capacity			-1,854		-$233		$233
Adjusted Total			**27,689**		**$3,487**	**$1,360**	**$7,004**

Source: Author created using data from the Ontario Planning Outlook (2016) and The Brattle Group (2018).

Table 3 | Generation Cost Pricing by Consumer Group, Current Approach and Proposed Approach

	Current Approach		Proposed Approach			
Customer Class	**Energy Cost**	**Global Adjustment**	**Energy Cost**	**Capacity Costs**	**OPG Energy Price Hedge**	**System-Wide Costs**
Class A	HOEP or MCP* (Marginal Cost Pricing)	Share of 5 Coincident Peaks (Demand Charge)	HOEP or MCP	Demand Charge	Volumetric	Fixed Charge or Taxes
Class B - RPP	Time-of-Use Prices (Time-Varying, Volumetric Pricing)		Time-of-Use	Demand Charge	Volumetric	Fixed Charge or Taxes
Class B - Non-RPP	HOEP (Marginal Cost Pricing)	Class B GA rate (Volumetric Pricing)	HOEP	Demand Charge	Volumetric	Fixed Charge or Taxes
Exports	MCP (Marginal Cost Pricing)	Do not pay	MCP	Demand Charge	Not Applicable	Not Applicable

Source: Author created using data from the Ontario Planning Outlook (2016) and The Brattle Group (2018).

Table 2 offers a retrospective and indicative estimate of the three components in 2017. First, the customer-specific capacity costs are estimated using data on projected 2017 generation capacity and reliability requirements form the IESO's Ontario Planning Outlook (2016) and estimates of the cost of building new generation presented in Brattle Group (2018) and in IESO (2019). The estimates are based on the methodology the IESO is proposing to calculate capacity payments under the Incremental Capacity Auction, one of the initiatives within the broader Market Renewal Initiative.

The IESO is required to maintain a certain level of capacity for reliability. In particular, it is required to maintain a level of capacity in the province so that the likelihood of not being able to supply firm demand due to insufficient capacity is no more than 0.1 days per year.[30] To meet this requirement, the IESO counts on all contracted and regulated generation capacity (i.e., all generation assets need to be available during system peak demand hours to ensure consumer demand is met reliably). The IESO is looking to procure capacity through the Incremental Capacity Auction on an unforced capacity basis. Installed capacity represents the maximum amount of energy that a resource can produce at any point in time, while unforced capacity represents the amount of energy that a resource can be expected to provide, on average, during system peak demand periods, accounting for the possibility of outages or in the case of renewables fuel unavailability. Table 2 presents both the installed and unforced capacity amounts for the different generation technologies and the amount of capacity the IESO estimated it would require in 2017 for reliability.

As part of the Incremental Capacity Auction, the IESO intends to use a capacity demand curve to represent the IESO's willingness to buy capacity by defining the prices that it is willing to pay for varying levels of reliability."[31] Modeling conducted by the Brattle Group (2018) and adopted by IESO (2019) suggest \$125,925/MW-y is an indicative estimate for the capacity price of the future auction as this price is consistent with the price that would prevail, on average, in a market that supports entry at the long-run marginal cost of capacity.

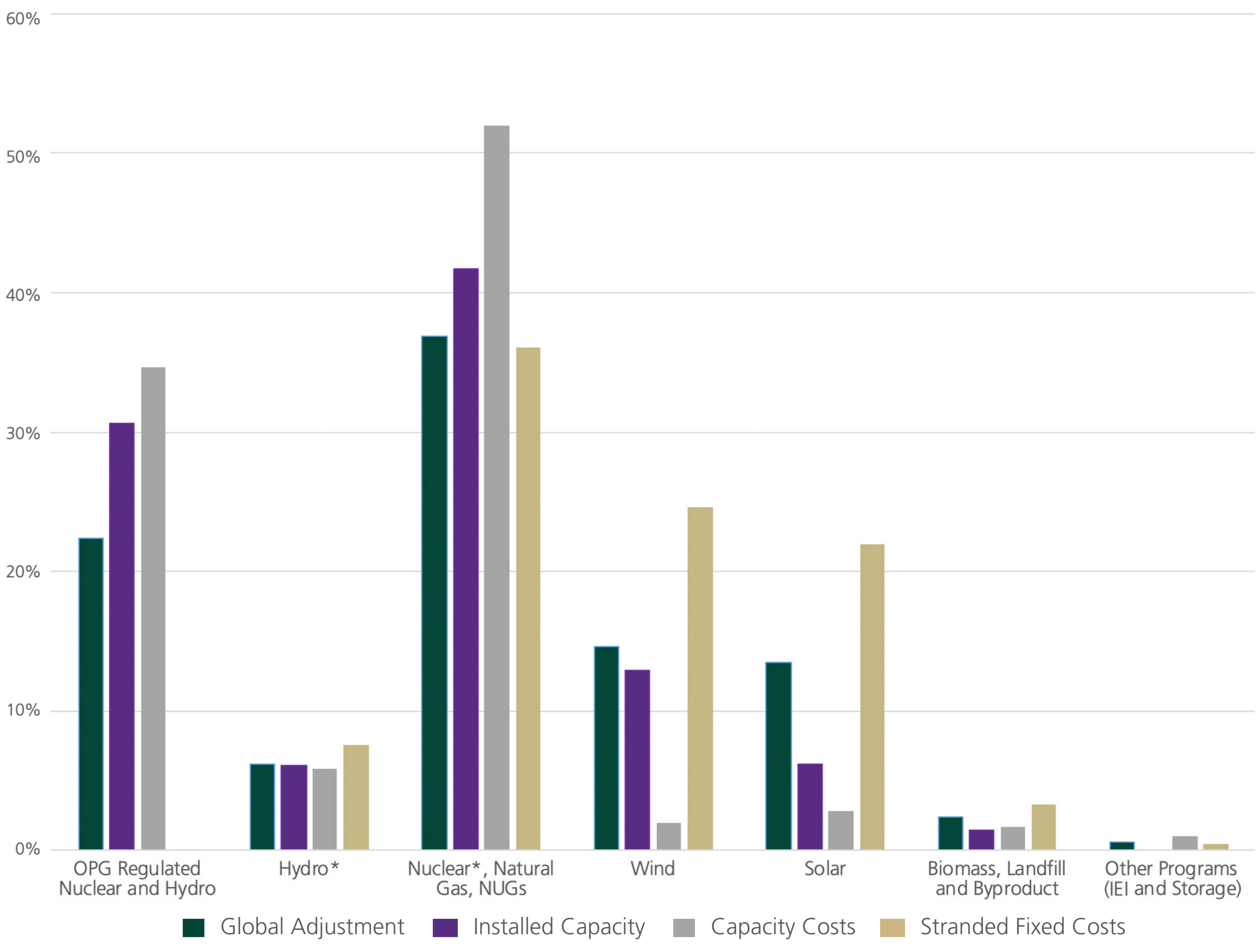
Consistent with how capacity payments would be calculated in the Incremental Capacity Auction, the capacity costs in the global adjustment can be estimated as the product of unforced capacity and the indicative capacity price. Under this approach, the total capacity-related costs embedded in the global adjustment in 2017 represented roughly \$3.7 billion. However, the amount of unforced capacity under contract or regulation with the IESO in 2017 was greater than the amount the IESO projected it would need in 2017 to meet its reliability standard when planning in 2016. That is, the province had a surplus of capacity. In a competitive auction, the capacity price would likely have cleared well below the long-run marginal cost of capacity so that the implicit capacity cost for all assets would have been lower than what is estimated in Table 2. For the purpose of the present analysis, the cost of surplus capacity is valued at the long-run marginal cost of capacity, subtracted from the capacity cost component of the global adjustment and added to the system-wide cost component. After subtracting the estimated cost of surplus capacity, the net capacity cost embedded in the global adjustment in 2017 is estimated at \$3.5 billion.

Second, the OPG energy price hedge provides Ontario consumers protection against volatile and high energy prices by rebating any revenues that the government-owned generator, OPG earns above what it needs to cover its total fixed and variable costs as defined by its regulated rates.[32] The amount of this price protection can be conceptualized as the difference between what OPG earns for the energy it provides, and what it would earn for its capacity in the competitive capacity auction, less the amount it needs to cover its approved costs. This value is estimated as the difference between what OPG receives from the global adjustment and its indicative capacity value as calculated in Table 2. In 2017, this is estimated as a charge to consumers of roughly \$1.4 billion.

The remainder of the global adjustment consists of system-wide fixed costs incurred to achieve different policy objectives, which in 2017 amounted to roughly \$7 billion. Arguably these also represent a form of stranded costs. The concept of stranded costs emerged as jurisdictions began deregulating natural monopolies and network industries. Stranded costs are the anticipated shortfall in net revenues on an incumbent's asset under competition that occur as a consequence of changes in regulatory or government policy.[33] As jurisdictions began introducing competition in previously regulated industries, incumbent utilities that had incurred costs prudently under regulation were at considerable risk of recovering the cost of these assets and of earning the regulatory approved return on invested capital. Many jurisdictions assumed the burden of these costs as part of the implicit regulatory contract with the incumbents. The costs were recovered from consumers through a separate competitive transitional charge.

In 1998, the Ontario government faced the issue of stranded costs when it decided to expose the generation services to competition. At the time, Ontario Hydro was carrying long-term debts of $26.2 billion and assets totaling $39.6 billion. The estimated market value of the assets was substantially less than the $39.6 billion. To ensure the financial solvency of the successor companies, the government assumed $19.5 billion of stranded debt and began repaying the debt through a Debt Retirement Charge levied upon Ontario ratepayers. The Debt Retirement Charge was equal to 0.7 cents per kWh of electricity consumed in Ontario. It was retired on March 31, 2018.[34]

Figure 3 | Share of Global Adjustment, Installed Capacity, Capacity Cost and Stranded Fixed Cost, 2017



* Non-OPG assets

Source: Author created from data available from the IESO.

Fast forward to today, when the transition from central planning and procurement to a competitive capacity auction exposes a difference between the competitive energy and capacity value of the contracted assets and the payments guaranteed through contract with the IESO. This difference is a reflection of costs stranded by previous policy decisions. Figure 3 provides a share comparison of the different components by generation technology for 2017, excluding the OPG energy price hedge. System-wide stranded fixed costs accounted for roughly 60 percent of the global adjustment in 2017.

The second step for achieving a more efficient and equitable allocation of generation costs is to price each component of the global adjustment separately using an approach that balances the principal criteria of efficiency and equity as discussed above. Table 3 offers suggested approaches for each consumer group.

First, capacity costs are essentially a consumer-specific fixed cost. Individuals that consume energy in the hours when the IESO projects capacity is most needed for reliability (i.e. system-peak demand periods) contribute to the need for capacity. Furthermore, with smart-meters, we can measure each consumer's consumption in these hours and charge them directly for their share of the cost. A demand charge based on consumption in the system-peak demand hours can approximate the marginal cost of adding new capacity on the system and encourage efficient consumption. A demand charge is also equitable in that it connotes the notion of user pay and cost causality. A coincident peak demand charge such as the one used to recover the global adjustment from Class A consumers represents one option.[35] Another option includes the one considered by the in OEB (2019), which would allocate capacity costs in each hour in a manner that is directly correlated to total Ontario electricity demand (labelled the demand shaped prototype). A third approach is the one prescribed in Alberta Energy (2017), the "weighted energy method," which would allocate capacity costs across several time blocks, with greater weight assigned to time blocks that contribute more to the cost of capacity and lower weights assigned to time blocks that contribute less to the cost of capacity. Ultimately, the efficiency merits of different charge determinants (i.e. coincident peak, demand-shaped pricing, weighted energy) is an empirical question worthy of study but outside of the scope of this policy report.

There is no efficiency or equity basis for dividing consumers into different classes (i.e. Class A and Class B consumers) for the purpose of recovering consumer-specific capacity costs through a demand charge.

Currently, exports do not pay global adjustment and the IESO has indicated it will not recover the annual capacity costs of the Incremental Capacity Auction from exports. This is a standard practice of all jurisdictions. The rationale for this approach is that Ontario does not consider export demand when it establishes its resource adequacy needs (i.e. exports do not benefit from the capacity built for Ontario peak demands). Furthermore, the IESO reasons that "to the contrary, exports provide benefit to the province by exporting excess energy to neighbouring jurisdictions."[36]

However, if capacity costs are a consumer-specific cost to be recovered on a coincident peak demand basis, there is an efficiency and equity argument that exports should pay their share of the capacity costs if they choose to buy Ontario energy in these hours. With a coincident peak demand charge, exports would pay for Ontario's capacity costs, only if they chose to consume in the coincident peak demand hours. This means that in all other hours, including those when there was excess energy, they would pay the marginal energy price, as they do today so that they would still have an incentive to export excess energy. Furthermore, if the export takes on the risk of transferring energy from Ontario to another jurisdiction during an hour in which it reasonably expects to pay part of Ontario's capacity costs, it must be doing so because it thinks the price it will receive in the other jurisdiction will cover the full cost of the transaction. In this sense, the price in the other jurisdiction must be sufficiently high, signaling a severe shortage of generation capacity in the jurisdiction. Consumers in this jurisdiction are willing to pay what it costs to have energy from Ontario transferred to their jurisdiction, including paying the marginal cost of adding capacity in Ontario. The consumers in this jurisdiction benefit from Ontario's investment in capacity and hence pay their share of the use of that capacity.

Second, part of the objective of the government's initial decision to regulate OPG's heritage assets was to provide Ontario consumers protection against volatile and high energy prices. In months with relatively high competitive energy prices, OPG rebates the revenues it earns above prescribed rates to Ontario consumers. In months with relatively low competitive energy prices, OPG recovers shortfalls from their prescribed rates through a charge on Ontario consumers. Initially, the rebate and charge were applied volumetrically on the basis of total monthly Ontario demand.[37] This helped to dampen the effects of the month to month energy price volatility on consumers. The implementation of the ICI distorted this relationship. Recovering the OPG energy price hedge component volumetrically would restore the initial policy purpose of the global adjustment.[38]

Finally, the third component of the global adjustment is a system-wide fixed cost incurred to achieve various government policy objectives. These costs also represent a form of stranded costs. As discussed above, there is no ideal policy for how to recover these costs, although balancing efficiency and equity suggests using a combination of fixed charges and volumetric prices. Ideally, the fixed charges should reflect the willingness and ability of different consumers to pay for grid-related electricity services. The challenge is finding a determinant that provides a reliable measure of willingness and ability to pay. In any event, the choice of a fixed charge would inevitably involve a value assessment on the preferred distribution of wealth in Ontario, an assessment generally best made by government.

As most of these costs were incurred for broader public policy objectives, a strong argument can be made that they should be recovered through the general tax base rather than through electricity rates. In any other sector, a government subsidy paid to a company to invest in clean technologies or to build a factory in Ontario to create new jobs would be recovered from tax payers instead of from consumers through taxes on product prices.

Recovery of the system-wide stranded costs could be accomplished through a separate tax item in the collection of personal income and corporate taxes. The amount of tax paid by an individual or a corporation could depend on an individual's taxable income. For example each tax payer (individual or corporate) could pay a "stranded asset" tax that is proportional to the tax payer's share of total Ontario personal/corporate taxes. Doing it as a separate tax would mean that it would not have to come at the expense of the funding of other social programs. Further, since electricity consumers are already paying for this cost through the global adjustment, it should not have a material impact on their disposable incomes, although it would likely mean that individuals or companies with higher taxable incomes would pay a higher share of the costs than they did previously through an electricity rate.

CONCLUSION

This report offers a practical approach for decomposing the global adjustment costs into three separate components (capacity costs, an OPG energy price hedge, and system-wide system costs), and argues that for efficiency and equity reasons, each component should be recovered as a separate charge using a different cost recovery method for each.

Decomposing the global adjustment into three separate charges at this point in the evolution of Ontario's electricity sector makes sense for at least two reasons. First, it is compatible and consistent with the objectives of current pricing policy initiatives, including the IESO's Market Renewal initiative and the OEB's RPP roadmap and utility enumeration initiatives. Second, it is timely given the changing technological landscape. Technological change is creating greater choice for consumers on how they use the integrated grid. As these solutions become more cost-competitive relative to grid-sourced electricity, there should be a gradual reduction in the use of and need for the traditional grid. This is a positive change on the whole that should take time to transpire, allowing for a gradual and rational transition. However, the current approach to recovering the global adjustment, which embeds fixed and sunk costs that are largely stranded from past policies, provides an extreme price incentive to reduce demand in peak demand hours. This is causing larger consumers to seriously consider distributed energy or behind-the-meter solutions and energy storage solutions.[39] While the extreme price incentive makes these solutions economic for the consumers that adopt them, the solutions are likely still more expensive than the actual avoided system cost of the consumer using grid-supplied electricity. This is not only inefficient, but as the Market Surveillance Panel has noted, it could hasten the transition to a more distributed energy system, causing the premature stranding of grid assets and eventually higher costs for Ontario electricity consumers on the whole. Decomposing the global adjustment and recovering only capacity-related costs during peak demand periods would reduce the potential for inefficient adoption of distributed energy solutions and future electricity costs for Ontario consumers.[40]

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END NOTES

[1]The overall project is termed "Market Renewal," and consists of three separate but related initiatives. For a summary of the Market Renewal program, see http://www.ieso.ca/en/Sector-Participants/Market-Renewal/Overview-of-Market-Renewal .

[2]Information on these consultations can be accessed at https://www.oeb.ca/industry/policy-initiatives-and-consultations/utility-remuneration and at https://www.oeb.ca/industry/policy-initiatives-and-consultations/rpp-roadmap.

[3]The announcement of this initiative can be accessed at https://news.ontario.ca/mndmf/en/2019/03/ford-government-to-launch-consultations-on-industrial-electricity-prices.html.

[4]For a discussion of the trends in distributed energy resources, see Schwartz et al (2017). For an Ontario perspective, see Gregg (2019) and Energy Transformation Network of Ontario (2019).

[5]For example, see Office of the Ontario Auditor General (2015), Trebilcock (2017) and Ontario Energy Board (2018).

[6]The policy reforms were introduced through Bill 100, Electricity Restructuring Act, 2004. The new legislation provided the OEB the responsibility of approving the RPP and created a new agency, the Ontario Power Authority with a mandate to ensure an adequate supply of electricity through long-term planning and procurement contracting. For further background see Hansard Transcripts available at https://www.ola.org/en/legislative-business/bills/parliament-38/session-1/bill-100.

[7]See: O. Reg. 429/04, Adjustments under Section 24.33 under the Electricity Act, 1998 as it came into force on January 1, 2005.

[8]At the same time that the government decided to rate regulate OPG's heritage assets, it imposed a revenue limit of 4.7 cents/kWh on 85 per cent of the output from its remaining assets. The difference between the revenues earned at market prices and the revenue limit were carried on OPG's balance sheet and the government's General Accounts. By 2014, OPG had closed all its coal-fired facilities. Furthermore, the government asked the OEB to regulate OPG's peaking hydroelectric facilities with the differences between the market rates and the regulated rates shifted from the General Accounts to the global adjustment.

[9]See https://news.ontario.ca/archive/en/2005/02/23/Ontario-Government-Introduces-Fair-And-Stable-Prices-For-Electricity-From-Ontari.html, accessed on January 3, 2019. Ontario Regulation 429/04 provided that the global adjustment be named the "Provincial Benefit" on invoices.

[10]On January 1, 2015, the IESO merged with the OPA to create a new organization that combined their respective mandates. The merged entity retained the IESO name.

[11]These were the policy objectives of the Green Energy and Green Economy Act, 2009. For further background see Hansard Transcripts available at https://www.ola.org/en/legislative-business/bills/parliament-39/session-1/bill-150/debates.

[12]The global adjustment changes from month to month for two reasons. First, it increases or decreases as the number of aggregate contracts with the IESO increase or decrease and as the regulated rates paid to OPG increase or decrease. Second, the global adjustment varies with the market revenues earned by contracted and regulated generators. Changes in the market revenues earned is a function of the changes in the HOEP; the higher/lower the average monthly HOEP, the lower/higher the global adjustment.

[13]See http://www.ebr.gov.on.ca/ERS-WEB-External/displaynoticecontent.do?noticeId=MTEwNzI0&statusId=MTY2MTgw accessed on January 3, 2019.

[14]Ibid.

[15]See Ontario Energy Board (2018).

[16]See Borenstein (2016). As Borenstein points out, efficiency requires prices equal the marginal social cost of production which includes the cost of any externalities produced such as greenhouse gas emissions. Externalities arise whenever the actions of one economic agent make another economic agent worse or better off, yet the first agent neither bears the costs nor receives the

benefits of doing so. For example, producing electricity using natural gas creates a negative externality – it leads to the emission of greenhouse gases that negatively affect the health of people and the environment. Absent some form of explicit price placed on greenhouse gases, natural gas generators will fail to internalize the cost of the externalities when pricing their output. This means that the price of electricity will be too low, and too much electricity will be consumed from a broader social perspective. It also likely means that there will be over investment in carbon emitting generation relative to non-carbon emitting generation.

[17]The extent to which departures from marginal cost pricing can lead to economic efficiency depends on how responsive consumers are to price changes (i.e., their elasticity of demand). If demand is inelastic (not very responsive to price), all else held constant, departures from marginal cost pricing lead to smaller efficiency losses. Electricity demand is often characterised as being highly inelastic in the short-term, and at the time of consumption, demand is likely perfectly inelastic. Empirical studies have shown evidence of some degree of elasticity in Ontario consumers. For example, see Ontario Energy Board (2018) and Lessem et al (2017).

[18]Borenstein (2000), at page 52.

[19]This paragraph describes the theory of peak-load pricing. The literature on peak-load pricing is voluminous. The interested reader may consult Crew et al (1995), Church and Ware (2000), Borenstein (2000) or Harris (2015).

[20]See Ontario Energy Board (2018) at page 18.

[21]Borenstein (2016) makes this distinction at page 6.

[22]The economic literature offers only limited guidance on the issue of fairness or equity. Horizontal equity implies the like treatment of people who are alike. It corresponds to common notions of fair play and non-discrimination. For example, if two people have the same pre-tax income, they would have equal after-tax incomes. Vertical equity is concerned with how different people are treated differently. This notion of equity is a more contentious. Vertical equity is typically concerned with the "preferred" distribution of wealth in society. What represents the "preferred" distribution of wealth is a normative question that requires a value judgement. For example, it can be argued that those who earn higher pre-tax income should pay higher taxes. Given that vertical equity involves a value judgment, there is no 'economic' answer and most economist defer to government or regulatory agencies to determine the preferred distribution. The task of economists is to determine how to achieve the preferred distribution at least cost or with least loss of efficiency.

[23]See C Harris (2015) for a review of early rate designs.

[24]The market clearing price reflects the social marginal cost to the extent that the Federal government's, Greenhouse Gas Pollution Pricing Act, S.C. 2018, c. 12, s. 186 properly accounts for the social cost of carbon. Under the Act, electricity generators have a direct compliance obligation when their emissions exceed a threshold amount, initially set at 50,000 tonnes, at which point a carbon price applies to the amount above emissions. The federal plan does not affect electricity imported into Ontario from US jurisdictions that continue to use fossil fuel generation, without similar comparable carbon pricing.

[25]The introduction of competition and competitive markets for generation services was expected to incentivize generation investment based only on the marginal energy price; there would be no need for a separate payment to recover the fixed costs of generation assets. However, as jurisdictions across North America gained experience with how "energy-only" markets operated in practice, many called into question the ability of these markets to provide generators with sufficient revenue to cover their fixed costs and to stimulate private invest in generation to the levels required to achieve traditional reliability standards. This has been termed the "missing money" problem – that prices do not rise high enough or often enough to attract required levels of generation capacity investment in an energy-only market. This led some jurisdictions to introduce "capacity markets" which offer generators an additional payment to make capacity available. For further explanation, see Charles River Associates (2017). Ontario choose to offer generators long-term contracts with price or revenue assurances to attract generation investment.

[26]See Ontario Energy Board (2018) at page 16. The Brattle Group (2018) estimates the cost of new entry for a single cycle generation facility at roughly $250,000 per MW per year. Breidenbough (2006) estimates the "value of loss load" for an average consumer at $2,000/MWh to $5,000/MWh US dollars or $3,325/MW to $8,320/MW in current Canadian dollars.

[27]The monthly global adjustment rate ($/MWh) is calculated by dividing the total monthly global adjustment cost not charged to Class A consumers, by the total monthly amount of energy consumed by all Class B consumers.

[28]This is true for RPP consumers that have a smart meter. The small number of RPP consumers that do not have a smart meter pay a set rate for electricity up to a certain level of consumption and a higher rate for all additional electricity consumed (i.e., a tiered price).

[29]The MSP also argues that the ICI methodology is complicated and non-transparent. Class A consumers do not know what the avoided global adjustment costs will be before they consume in a peak demand hour. They must predict in advance whether the hour will be one of the five coincident peak demand hours, their share of demand in the hour, and what the size of the GA will be in the following year. The MSP argues that not knowing the cost of consumption complicates the decision of when to consume; consumers risk reducing consumption during hours that turn out not to be one of the five coincident peak hours which results in losses to the consumers and an efficiency loss more generally.

[30]Independent Electricity System Operator (2019) at page 225. Resource adequacy refers to the ability of an electric system to provide sufficient supply to serve firm demand in aggregate. A resource adequacy standard is an expression of the acceptable frequency or duration of interruptions of power to firm demand caused by insufficiency of supply resources. The Northeast Power Coordinating Counsel's resource adequacy criteria requires that "Each Planning Coordinator or Resource Planner shall probabilistically evaluate Resource Adequacy of its Planning Coordinator Area portion of the bulk power system to demonstrate that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies is, on average, no more than 0.1 days per year.

[31]See Independent Electricity System Operator (2019) at page Ibid, at page 153.

[32]The OEB approved rates in 2017 were roughly $77.96/MWh for the nuclear assets and $41.67/MWh for the hydroelectric assets. See PAYMENT AMOUNTS ORDER EB-2016-0152, ONTARIO POWER GENERATION INC. Application for payment amounts for the period from January 1, 2017 to December 31, 2021.
[33]See Sidak and Spulber (1997) at page 28.

[34]See https://www.fin.gov.on.ca/en/tax/drc/index.html.

[35]All U.S. jurisdictions that operate capacity markets use a coincident peak demand charge. See Alberta Energy (2017) for a comparison of different capacity cost allocation methodologies. The IESO is proposing to recover the annual costs of the Incremental Capacity Auction using a coincident peak demand charge. See IESO (2019) at page 225.

[36]See Independent Electricity System Operator (2019) at page 226.

[37]If the OPG energy hedge amount was recovered volumetrically in 2017, it would have been a charge in all months, and roughly $10/MWh on average. That the hedge was a charge in 2017 might be expected given that the average annual HOEP in 2017 was relatively low at $15.80/MWh compared to the average annual HOEP for the prior 10 year period (2008 to 2017), which was $29.53/MWh.

[38]It has been nearly 15 years since the policy to regulate OPGs rates was introduced. Since this time, considerable change has occurred within the hybrid electricity market. There are now many private generators in the market and OPGs share of output is much smaller. The competitive energy price (HOEP) is generally lower, less volatile, and represents a much smaller component of a typical consumers electricity cost. Furthermore, the introduction of a capacity auction will offer new competitive revenue opportunities for OPG to cover its fixed operating costs that did not exist at the time of the initial policy. These changes may have affected the need to or benefit of regulating OPG's assets. Given the policy evolution, there is arguably merit to having a public consultation to review the current treatment of OPG's assets to asses the costs and benefits of the existing regulatory regime.

[39]For recent evidence of this activity see https://www.greentechmedia.com/articles/read/batteries-benefit-from-ontarios-bizarre-energy-market#gs.g79rmb.

[40]As a postscript, the changes to generation cost pricing proposed in this Policy Brief are likely to lead to a redistribution of wealth across different consumer groups and even within consumer groups. Furthermore, shifting the stranded fixed costs from electricity rates to taxes would require some time to work through the provincial budgeting process. It would be prudent to gradually phase in the changes to avoid possible large shifts in wealth and to allow all customers time to adapt their investment planning decisions and consumption habits. One approach to phasing in the changes could be to separate the capacity costs from the global adjustment in the first phase. The capacity costs could be recovered from all consumers, including exports, using a demand charge such as the current coincident peak charge, the OEB Staff's recommended demand-shaped pricing, or the Alberta weighted energy approach. The remainder of the global adjustment could then be recovered volumetrically. Realizing this phase should help reduce the risk of hastening the investment in distributed energy solutions. In the second phase, the system-wide stranded fixed costs could be gradually shifted from electricity rates to a stranded asset tax. This could be done over a period of two to three budgeting periods.

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