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Staff Research Paper:

Examination of Alternative Price Designs for the Recovery of Global Adjustment Costs from Class B Consumers in Ontario

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Executive Summary

In 2015, the Ontario Energy Board (OEB) published the *Regulated Price Plan (RPP) Roadmap* [1], a document that summarizes research into the RPP's successes and shortcomings, and provides a direction for future renewal of the RPP. The *Roadmap* identifies several key drivers that prompt the need to reconsider aspects of the RPP in order to improve its effectiveness at meeting policy objectives. Key among these are objectives to provide consumers with a plan they understand; and to develop a plan whose price structure gives consumers incentives and opportunities to use electricity in a manner that also has efficiency benefits for the electricity system.

Following the publication of the *Roadmap,* RPP pricing pilots for residential consumers were initiated in selected areas across the province in order to test different approaches to pricing and information sharing. Four pilots involving more than 15,000 customers were deployed in 2018. Final results of these pilots are expected in the latter half of 2019.

Another element of the work outlined in the *Roadmap* pertains to the difference in how global adjustment (GA) costs are collected through electricity prices paid by consumers enrolled in the RPP and those who are not. Those consumers who do not pay RPP prices, sometimes referred to as non-RPP Class B consumers[1], pay the GA as a separate, flat volumetric charge that varies monthly. This flat GA charge has the effect that the GA portion of electricity prices that non-RPP Class B consumers pay provides a markedly weaker incentive to proactively manage their energy consumption relative to RPP consumers and Class A consumers alike. In the *Roadmap*, the OEB observed that a consistent approach to the recovery of GA costs from Class B consumers would be more equitable and could underwrite the development of a range of price options that could more effectively address consumer expectations.

Alternative approaches to the recovery of GA costs from Class B consumers is the subject of this paper. A range of pricing prototypes for recovering GA costs are introduced and, within a simplified model of the electricity system and of electricity consumers, evaluated based on the principles of revenue adequacy, economic efficiency and consumer bill impact.

Based on this analysis, OEB staff concludes that an electricity price that charges consumers a GA price that is directly correlated to total Ontario electricity demand – labelled the demand-shaped prototype – yields the most positive results for electricity consumers. The paper closes with a discussion regarding the practical implementation of a new class B price with high-level consideration for future changes to the Ontario electricity market. Further research is currently ongoing that will examine the consumer impact and acceptance of new pricing models as the policy development process continues as outlined in the *Roadmap.*

The remainder of this summary describes prototypes that were examined, presents the primary findings regarding their evaluation and concludes with a collection of lessons that were learned from this analysis.

[1] To a close approximation, Class B consumers are those with peak electricity demand less than 1000 kW while those with demand of 1000 kW or more are considered Class A. Class B consumers can be further divided by those participating in the RPP (all residential consumers and general service customers with a peak demand less than 50 kW) and those who are not. These classifications determine how GA costs are recovered from individual consumers. See Appendix B for precise definitions of Class A and B consumers along with the way in which they are charged for electricity consumption.

Pricing Prototypes

All of the pricing prototypes introduced in this paper have been designed to be revenue-adequate in that they fully recover market and GA costs over the cost recovery period. Prototypes assessed are:

Status Quo pricing (SQ) – a simplified version of the class B pricing in place in 2018, used as a baseline against which all other pricing profiles are compared for the purposes of estimating demand response impact.

Flat pricing (Flat) – the least dynamic prototype, charging consumers the same price in all hours so as to recover all market and GA costs over the cost recovery period.

Expanded time-of-use pricing (TOU) – a natural extension of the existing status quo RPP time-of-use pricing structure but applied to all class B consumers.

Demand-shaped pricing (Demand) – market costs (*i.e.* those costs that are paid to generators through the real-time energy market which defines the Hourly Ontario Electricity Price (HOEP)) are recovered through HOEP; GA costs are recovered in a fashion that is directly correlated with total Ontario demand in each hour.

Supply-shaped pricing (Supply) – market costs are recovered through HOEP; GA costs of different generators are recovered in the hours in which those generators produce electricity.

High N pricing (HiN) – market costs are recovered through HOEP; some fraction (here 50%) of GA costs are recovered based on the consumption of class B consumers during the highest demand hours within each cost recovery period.

Economic Efficiency

The primary method to evaluate pricing prototypes in this paper is economic efficiency. Staff's analysis assesses the relative economic efficiency of up to two specific variants of each prototype over a forecast period of 2018-2031. The variants are chosen so as to provide a low- and high-range version of each prototype (*i.e.* the range between the lowest and highest prices charged) based on a reasonable range of the adjustable parameters available for each prototype.

The approach taken in this analysis marks a break with many prior investigations of this type. Commonly, evaluators have tended to focus on estimating the amount of short- and long-run avoidable system costs associated with price-responsive changes in demand. These techniques have tended to ignore the question of the opportunity costs to consumers of foregone consumption during periods of higher prices (relative to the status quo) or the direct value to consumers of increased consumption during periods of lower prices. In an effort to consider this dimension of the analysis as well, quantitative estimates of economic efficiency considered in this paper include:

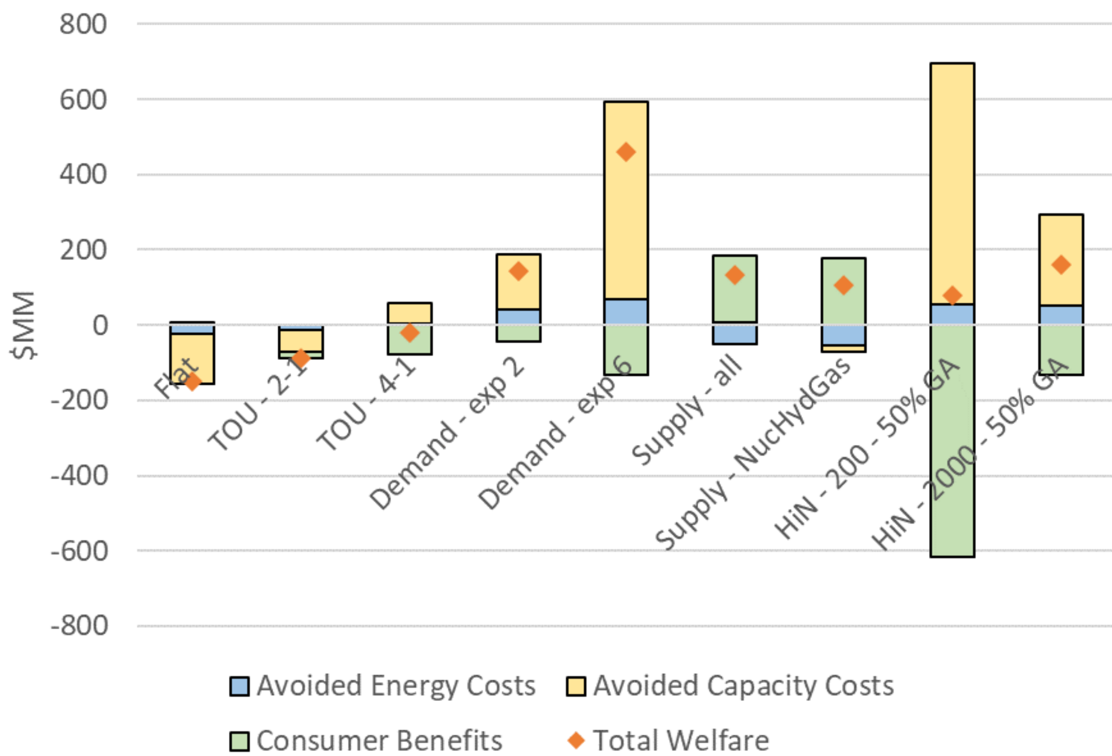
1. The avoided or added cost of energy and capacity due to the change in demand induced by each pricing variant,

2. The direct benefit or cost to consumers (and, in some cases, producers) of the change in demand induced by each pricing example.

This analytical design is consistent with the underlying economic theory that both the system-level and consumer-level impacts of a revised pricing plan must be considered when evaluating its overall economic efficiency attributes.

In Figure 1, the results of this economic evaluation for all variants are shown for the forecast year 2030. The range of outcomes for the demand-shaped pricing examples indicate that the demand-shaped prototype is the most economically efficient in 2030 relative to the other prototypes studied. In other words, the demand-shaped prototype exhibits the highest overall combination of avoided cost and consumer benefit among all prototypes studied.

Figure 1: Avoided cost, consumer benefit and net benefit in forecast year 2030.



The first word of each reference name along the horizontal axis refers to the prototype from which the specific example was derived as defined above. The remainder of each label describes the specific variant of the prototype that is being studied – the two variants for each prototype exhibit a reasonable range of parameters and can be considered a “high” and “low” case scenario for each prototype. The detailed formulation of each variant presented along the horizontal access is described in section 3 and further in Appendix A.

A summary of the economic efficiency analysis is presented in Table 1 below. It shows the average change in annual peak demand along with the net present value (NPV) of annual avoided costs, consumer benefits and net benefit (avoided costs plus consumer benefits) for each pricing variant over the forecast period.

Table 1: Summary of economic efficiency results over the forecast period 2018-2031.

	Flat	TOU - 2-1	TOU - 4-1	Demand - exp2	Demand - exp6	Supply - All	Supply - NucHydGas	HiN - 200 - 50% GA	HiN - 2000 - 50% GA
Average percentage change in annual peak demand	2.3%	0.6%	-2.0%	-2.9%	-11.5%	0.1%	0.5%	-12.7%	-4.8%
NPV Avoided Cost ($M)	-$943	-$361	$626	$1,338	$4,180	-$294	-$446	$4,429	$1,996
NPV Consumer Benefit ($M)	$48	-$54	-$1,135	-$230	-$1,478	$1,666	$1,724	-$5,972	-$1,138
NPV Total Welfare ($M)	-$896	-$415	-$508	$1,108	$2,703	$1,372	$1,278	-$1,543	$858

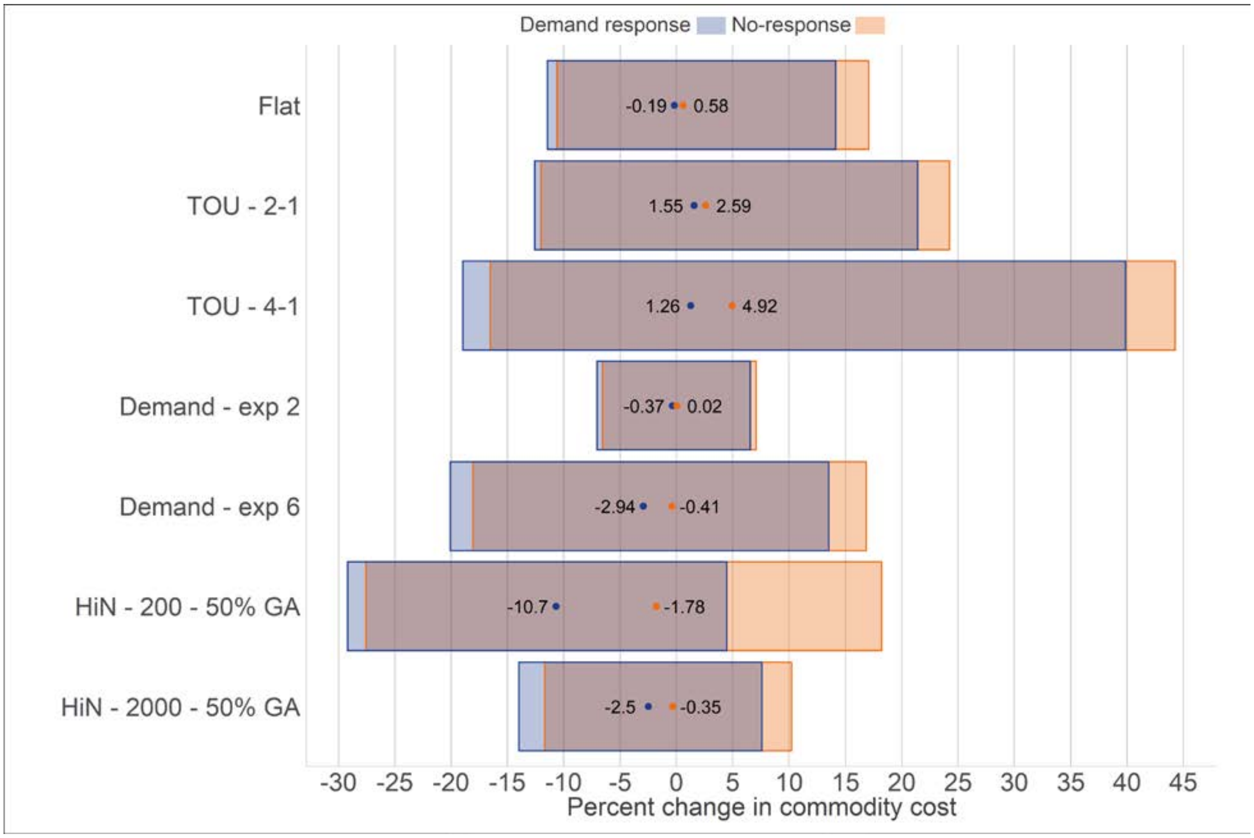
The NPV values were calculated over the entire forecast period assuming a nominal discount rate of 6%. Discrepancies between the sum of Avoided Cost plus Consumer Benefit and Net Benefit are due to rounding to the nearest integer dollar value.

Consumer Bill Impact

While economic efficiency remains a focus of OEB staff's evaluation, a preliminary analysis of the consumer-level cost consequences for non-RPP class B consumers was also conducted. Using a database of historical hourly electricity load profiles of close to 7,000 general service consumers with demand between 50 and 1,000 kilowatts (kW), the change in each consumer's electricity supply costs that would be induced by each pricing variant relative to status quo pricing is calculated.

Two approaches to this analysis are employed for each pricing variant. One assumes no load response to the new pricing (No Response scenario); the other assumes a demand response scenario wherein each consumer adjusts to higher and lower prices in each hour relative to the status quo price (Demand Response scenario). Figure 2 below shows, for each variant, the average cost impact and the range of impacts for 98% of customers. Both the No Response scenario and the Demand Response scenario are displayed. OEB staff cautions that it has not established whether this sample is representative of Ontario consumers in these consumer classes; the analysis should be taken to be indicative only. OEB staff notes that a more rigorous analysis as well as further consultation is planned, as discussed below.

Figure 2: The change in annual commodity cost relative to the status quo price under each pricing option for General Service consumers in the No Response and Demand Response scenarios.



Average impacts are encoded as a point. Each bar represents an impact interval that 98% of consumers reside within.

Lessons Learned

The results of this analysis support the observations first made in the *Roadmap* that a more dynamic design for the recovery of GA costs can support more efficient, long-term outcomes for the electricity system. The most salient lessons to be learned from this analysis are as follows:

1. **Need to balance system savings with consumer benefit**
   While prices that produce demand-responsive behaviour can increase overall net economic benefit by deferring infrastructure needs, extreme pricing can reduce overall benefit by inducing consumers to avoid consuming even when it would otherwise be beneficial for them to do so. The need for this balance is best exemplified in the analysis of the High-N pricing prototype where the negative impact to consumer benefit due to demand reductions during the highest N electricity demand hours was estimated to be greater than the resulting system cost savings.

2. **Correlating GA prices with demand yields positive economic efficiency results**
   Allocation of GA costs more in line with system demand can yield higher economic

benefits relative to both the current Class B price design as well as relative to other scenarios studied. It is effective at inducing demand response without inducing overly costly curtailment in hours where consumer response is not needed.

3. **GA prices that align with the cost/dispatch of generation are not optimal**
   Allocation of GA costs in line with resource (supply) type and cost is less economically efficient than other prototypes studied. It is less effective at spurring demand responsive behaviour because such prices do not always align high prices with periods of high demand. Nevertheless, such a shaping of price does appear to offer positive consumer benefits relative to status quo pricing.

4. **Reductions in consumer benefit can swamp system savings for Class A-like GA allocation**
   Allocation of half of GA costs into the highest electricity demand hours, a design similar to pricing under the Industrial Conservation Initiative (ICI) applied to Class A consumers, is generally as effective at deferring new system needs as demand-based pricing approaches but yields significant reductions to consumer benefit such that the likelihood of overall negative net benefits rises as the number of targeted hours diminishes. As a result, the High-N prototype risks being significantly less economically efficient than the other options studied.

5. **Reallocation of GA designs can reduce costs for consumers able to respond to better price signals, but greater information regarding consumer acceptance is required**
   An analysis of the consumption patterns of about 7,000 larger general service customers confirms that the cost consequences of alternatives to the status quo Class B GA price can generate moderate savings on average and a range of individual savings for those consumers who can respond to price signals. However, more work remains to be done to understand consumers' views about price changes. This includes how consumers would trade off cost causality in prices in order to gain more predictability in the prices they pay. It is also important to know more about their preferences – their attitudes not merely to price increases in periods of higher demand, but also their disposition toward the prospect of lower prices in lower-demand periods – and their views of the opportunities, costs and interest in managing greater price exposure through demand response and other measures. The RPP pilots are underway and additional direct engagement with consumers is planned. Both activities are expected to shed light on these issues.

Next Steps

The analysis in this document illustrates that significant system – and consumer – benefits can be obtained through more dynamic pricing approaches than those currently charged to class B consumers. Preliminary investigations of individual consumer bill impacts show that the dispersion of impacts of a time-varying GA charge for a significant portion of consumers are within ranges that have generally been held to be reasonable.

However, more work remains to be done to understand the dispersions of costs and benefits of any eventual changes, and to understand which groups of consumers may be best positioned to take advantage of more dynamic prices, and which may be challenged to adapt to greater variation in electricity costs from day-to-day and from season-to-season.

To that end, OEB staff is preparing to expand upon further work identified in the *Roadmap:* engagement with small business and other general service consumers. Building on work underway to collect more detailed and comprehensive data on consumption patterns of businesses in Ontario, OEB staff intends to engage with a wide range of consumers to better understand their priorities and preferences regarding pricing and the feasibility of integrating demand response into their business processes. It will also conduct further impact analysis at the consumer level with a representative sample that is also intended to include more granular information on business type, geography and other potentially relevant factors.

In addition, OEB staff intends to solicit comments from interested parties within the electricity sector on the policy and economic merits of alternative price designs for recovering GA costs. The results of RPP pilots, when available, will also inform further pricing work as it pertains to residential and other low-volume consumers.

While OEB staff remains interested in the issue of improvements in GA design and sees merit in engendering discussion among stakeholders on this topic, no changes to the allocation or design of GA costs can be effected without amendment to Ontario Regulation 429/04. As stated in the *Roadmap*, the OEB is committed to working with the government and the Independent Electricity System Operator (IESO) to address issues that have been identified.

1 Introduction

In 2015, the Ontario Energy Board published the *Roadmap*, a document that summarizes research into the RPP's successes and shortcomings, and provides a direction for future renewal of the RPP. The *Roadmap* identifies several key drivers that prompt the need to reconsider aspects of the RPP in order to improve its effectiveness at delivering on policy objectives. Key among these objectives is to develop an understandable plan whose price structure gives consumers incentives and opportunities to use electricity in a manner that also has efficiency benefits for the electricity system.

The *Roadmap* finds that, while RPP TOU prices have demonstrated modest effectiveness in driving conservation and shifting in the timing of electricity consumption in the residential consumer sector, the same has not been evident in the small business sector. Some concerns regarding the design of the RPP have been identified in the *Roadmap*:

- On-peak to off-peak price ratios are too small to drive more substantial energy conservation and shifting behaviour and, hence, are not affording consumer opportunities to drive bills lower in the long run,
- There is little comprehension of the electricity system among all consumers, and poor understanding of the charges on their electricity bills.

In light of these findings, the *Roadmap* articulates a new set of key objectives for a renewed RPP:

- Peak demand reduction,
- Efficient system operation,
- Consideration of not merely current but also long-run system costs.

In order to understand pricing and program design options that would support these additional new objectives, the OEB determined to pursue pilots to help ensure that resultant changes to the RPP could be informed by evidence of their effectiveness, acceptance by customers and suitability for deployment across the province.

In 2016, the OEB solicited proposals from Ontario electricity utilities for pilot projects that would test price and non-price features, such as critical peak pricing and load control automation. The OEB selected proposals from London Hydro, Alectra Utilities, Oshawa Power, and a group of six utilities called CustomerFirst. These four RPP pilots are testing eight different pricing plans and non-price features such as in-home controls and real-time feedback on consumption. The pilots, which involve more than 15,000 customers from across the province, were deployed in 2018. Final results of these pilots are expected in the latter half of 2019.

Another focus of the *Roadmap* pertains to the difference in treatment between consumers eligible and enrolled in the RPP, and other members of Class B who are either not eligible for RPP or not enrolled in it[2]. The non-RPP eligible members of Class B only receive HOEP as a dynamic incentive to more proactively manage their energy consumption. The price signal

[2] See Appendix B for tables showing the pricing designs available to both Class A and Class B consumers within Ontario along with the eligibility requirements of each sub-class of Class B consumer.

provided by HOEP to reduce consumption during periods of peak demand is, on average, weaker than that provided by RPP TOU prices.

The difference in treatment between the two groups within Class B also leads to a potential spillover effect initially discussed in the *Roadmap*. As a result of the ICI, the division of GA between Class A and B depends on their respective ratios of consumption during the top five peak hours of consumption in a year for the province as a whole. In Class B, RPP consumers are provided a greater direct incentive to avoid peak consumption via the on-peak TOU price (assuming the top five peak hours occur during RPP on-peak periods). However, the efforts RPP consumers make to conserve and shift consumption during the five peaks of the year result in a lower GA burden for all members of Class B, not just those RPP consumers making the conservation or shifting effort. The *Roadmap* refers to this as the GA misalignment problem.

This misalignment in GA recovery highlights the difference in treatment between RPP and non-RPP Class B consumers. Thus, a key objective of the *Roadmap* is to develop a more symmetric or rationalized pricing plan that would shape GA charges for all members of Class B.

At the same time, the *Roadmap* highlights the matter of long-run marginal costs and how to better design a pricing plan that would more effectively induce reductions in long-run system costs by reducing the need for investments to meet peak demands.

This paper will inform the next steps in redesigning the RPP to support policy objectives suitable for the key challenges and opportunities over an upcoming system planning horizon that is likely to see significant change: change in energy demand through continued economic transformation, continued alteration in the supply landscape while nuclear units are refurbished, and further evolution of the grid as new technologies become more cost competitive relative to traditional grid and generation investment.

OEB staff notes that while it sees merit in engendering discussion among stakeholders on this topic, no changes to the allocation or design of GA costs can be effected without amendment to Ontario Regulation 429/04. As stated in the *Roadmap*, the OEB is committed to working with the government and the IESO to address issues that have been identified.

1.1 Overview of the Paper

This paper conducts a data-intensive study of a variety of potential pricing designs for Class B consumers, and evaluates their performance relative to three metrics through simulations of price and customer demand response.

1.1.1 Pricing Prototypes

The basic pricing plans under consideration are referred to as pricing prototypes – simplified price designs containing only the most fundamental features of the pricing concepts they represent. They are not necessarily intended to reflect the final forms that such pricing plans might take if actually applied in the real world. This helps keep attention focused on the essential properties of the pricing plans and avoid complications that would distract from the analysis.

An important consideration is the fact that, in this analysis, simulations of the performance of the pricing plans are grounded on the assumptions that all Class B consumers are fully informed about the pricing plan they are responding to, are aware of the electricity price in any given hour and will respond to those prices as a typical electricity consumer. These assumptions are necessary to ensure that each pricing prototype is evaluated on its intrinsic economic merits. While implementation factors such as communication and consumer knowledge are fundamental to the outcomes that can be achieved through pricing, this stage of the analysis suspends such considerations in order to focus on the efficiency analysis.

1.1.2 Principles

The pricing prototypes are examined relative to three metrics:

- Revenue adequacy
- Economic efficiency
- Consumer bill impact

Revenue adequacy refers to the need to recover all electricity supply costs from consumers. A price that fully recovers all supply costs is considered to be fully revenue adequate. In the case of the prototypes introduced in this study, revenue adequacy is built in by design as each prototype has been constructed to meet revenue requirements relative to the forecast data utilized.

Economic efficiency in each pricing prototype is assessed by first estimating the changes in consumption that each prototype is expected to induce and then calculating the resulting short-run and long-run costs incurred or avoided due to the change in consumption. In addition to examining the savings and costs to the system as a whole – savings/costs that accrue to all consumers – this paper also estimates the savings/costs that each prototype imposes in the form of the value of consumption and production that is incented/deterred by the prototypes – savings/costs that impact on the individual level. The underlying economic theory is clear that both the system-level and consumer-level impacts of a revised pricing plan must be considered when evaluating its economic efficiency attributes[3].

This methodology marks a break from much prior literature, which has tended to ignore the value of consumption and treat savings in system expansion costs as the only relevant long-run considerations. In cases where system expansion costs are the sole metric by which options are evaluated, the most economically efficient pricing design would always be the one that limits growth in the electricity system the most – an untenable view.

The result of this evaluation is a relative comparison of the overall economic efficiency of each prototype for class B consumers collectively. Each individual consumer, however, will experience individual impacts on their electricity bills as a result of any change to electricity pricing. Even in the absence of any change in electricity consumption, some consumers' bills will go up while others will go down as a result of the new prices. To help gain a better understanding of the expected range of consumer bill impacts, this paper examines the

[3] Appendix D reviews the relevant economic and policy literature in this area.

distribution of the commodity cost impacts on consumers' bills for each prototype across a collection of close to 7,000 individual general service consumers.

The purpose of this paper is to establish an analytical basis that identifies which basic pricing design aspects are most optimal from an economic efficiency and consumer bill impact perspective. However, OEB staff recognizes and acknowledges that additional considerations – considerations such as fairness, simplicity, transparency and consumer acceptance – must be taken into account when designing and implementing pricing plans that will be charged to real consumers. Such considerations, while important and briefly discussed in section 4.2, are less appropriately applied to the simple pricing prototypes examined in this paper and more appropriately addressed at a later time when more detailed and applicable pricing options are being considered. Accordingly, the OEB plans to engage in broad consultation as well as further quantitative and qualitative research on potential pricing options.

1.1.3 Methodology and Evaluation of Results

Section 2 provides a description of the simulation and evaluation methodology and how the effects of each pricing prototype on consumption outcomes translates into costs and benefits resulting in the relative evaluation of the economic efficiency of each prototype. Section 3 presents the results of this analysis, detailing the relative economic efficiency of each prototype. This paper concludes with a general discussion, summarizing the results in a series of "lessons learned" and indicating the future course of pricing design for class B consumers.

2 Methodology of Quantitative Analysis

In order to evaluate various aspects of pricing for class B consumers, this paper defines a wide range of alternative pricing prototypes, each with several adjustable parameters, to be applied to all class B consumers, as a means of contrasting the benefits and drawbacks of available alternatives. Up to two variants of each prototype are chosen and evaluated using a forecast of electricity system parameters over the forecast period 2018-2031 provided by the IESO. This section provides a thorough description of the method by which each is evaluated.

The key steps are as follows:

1. For a given pricing prototype, choose values for each parameter so as to define a specific price in all hours over the forecast period; this specific price is referred to as a variant of the prototype.
2. Estimate the expected demand response of each variant relative to the status quo price using empirically estimated price elasticities.
3. Calculate the avoided costs to the electricity system that are induced by the demand response.
4. Calculate the economic impact to consumers of the demand response.
5. Combine steps 3 and 4 to arrive at the net economic benefit or "total welfare"[4] of the pricing example.
6. Repeat for all variants of each pricing prototype.
7. Compare the results to each other over the forecast period to arrive at a relative evaluation of the economic efficiency of each pricing example.

Given the numerous assumptions and forecasts involved in this exercise as described in more detail below, the precise quantitative results are subject to considerable uncertainty. Such analytical simplifications are necessary to produce tangible results. However, given that each pricing variant was evaluated using the same procedures and data, the *relative* comparison of each variant is likely to be robust to forecast errors even if the *absolute* value of the demand and economic impacts are less certain.

2.1 Defining Pricing Prototypes

Six pricing prototypes were designed for this analysis, each defining prices in each hour over the forecast period. These pricing prototypes cover a wide range of options, from very static options where electricity prices change little from hour-to-hour, to highly dynamic prices that exhibit significant swings in price. Each pricing prototype is introduced in section 3 and the technical definition of each is provided in Appendix A.

Each pricing prototype is defined by a few key input parameters:

1. The HOEP in each hour
2. The Ontario electricity demand in each hour, both in total as well as for class B consumers and several subclasses of class B consumers as applicable

[4] Throughout the body of this paper OEB staff uses the term "total welfare" to refer to the sum of avoided costs and consumer benefit. However, in the executive summary and in less technical materials discussing this research that are intended for audiences who may not be familiar with concepts of welfare economics, the same term will be referred to as the "net benefit."

3. The GA costs attributed to class B consumers
4. The hourly generation and GA cost of different generation types (applicable only to the supply-shaped pricing prototype).

In wholesale markets in operation today, each of these input parameters is defined in real time rather than known precisely in advance. Nevertheless, for the sake of clarity and simplicity in this analysis, it is assumed that the price in each hour can be defined unambiguously over the period 2018-2031 based on forecast input parameters provided by the IESO presented in Appendix C.

Electricity generators are paid through the real-time energy market as well as through the GA. These costs are then recovered from electricity consumers through the price paid for electricity. As such, it is necessary that the electricity price, however defined, must recover the total cost of payments to generators through the market and through GA over time. The amount of time over which these costs are recovered from consumers is called the cost recovery period. A price plan that fully recovers costs over the cost recovery period is said to be revenue adequate.

Given the necessity to recover all generation costs over time[5], each pricing prototype is defined so as to be revenue adequate by definition as described in Appendix A. For the purposes of this analysis where perfect knowledge and foresight of demand and cost is assumed, revenue adequacy can be rigorously defined and ensured[6].

Each pricing prototype under consideration has a number of adjustable parameters. However, in order to estimate the expected demand response relative to the status quo pricing and the subsequent value of that demand response, specific variants of each prototype must be defined. In order to keep the presentation of results manageable, two variants of each prototype were chosen that highlight a reasonable range of the adjustable parameters.

These variants are not exhaustive and each pricing prototype offers a continuous range of options beyond these examples. The variants chosen are not meant to decide on the fundamental value of each prototype as defined but rather show the range of economic value each is capable of and how the nature of that value is different depending on the dynamics of each particular prototype.

2.2 Demand Response of Variants of Pricing Prototypes

Economic theory and dozens of empirical studies have established that electricity demand falls with increasing energy price, and rises with decreasing energy price. The consumer's sensitivity to changes in price can be evaluated by the price elasticity of electricity demand, a normalized measure of the percentage change in quantity demanded in relation to the percentage change in price.

Economic literature reports two types of elasticities that are relevant for this analysis: own-price elasticity of demand and elasticity of substitution. The own-price elasticity of demand measures

[5] There are cases where the full cost of generation is not recovered, such as in the case of the price charged to RPP-eligible consumers under the Fair Hydro Plan. While this may change the overall level of cost recovered within a given cost recovery period, such situations do not change the results of the analysis. The Fair Hydro Plan is briefly discussed in section 4.3.4.

[6] In real-world pricing systems, the absence of perfect knowledge and foresight can lead to the adoption of variance accounts so as to ensure revenues recover costs over the long term. Such a balancing system could be implemented, in principle, for each of the pricing prototypes under consideration but such variances are ignored in the current analysis.

how consumers adjust their demand to changes in the price of goods. In the context of electricity rates, own-price elasticity refers to how consumers' demand for electricity in a given hour changes when the price for consumption in that hour is changed; and to how overall demand in a given day or billing period changes when electricity rates change. Own-price elasticities are typically negative, reflecting the negative slope of a demand curve.

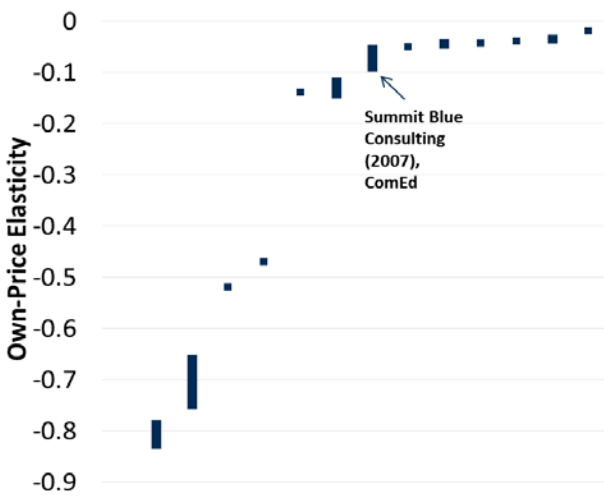
Consumers' demand for goods is also affected by the elasticity of substitution, which describes how easily consumers substitute one good for another, or goods in different time periods for one another, when relative prices change. In the context of electricity rates, the elasticity of substitution quantifies the percentage change in on-peak to off-peak consumption relative to a change in the on-peak to off-peak price ratio.

This section and the next review the research and analysis conducted by The Brattle Group for the OEB to estimate the expected demand response from each pricing option considered as well as the resulting economic value of that demand response.

The discussion begins with a presentation of measured elasticities from studies over the past 15 years on residential and commercial ratepayers to determine own price and substitution elasticities to be used in this study.[7] Large variations in elasticity estimates are observed, which can be attributed to differences in region, rate type, sector and time period among studies. Figure 3 and Figure 4 below indicate the range in short-run own-price and substitution elasticities that have been measured and reported in the recent literature on the subject. Estimates of own-price elasticity range between -0.02 and -0.84. Estimates of elasticity of substitution range from -0.06 to -0.38.

[7] Class B consumers may have demands ranging from 0 to 1,000 kW and includes residential, commercial and industrial consumers. There are relatively few studies comparing industrial, commercial, and residential elasticities for a given location and period so broad conclusions are not drawn regarding the relationship between elasticities of these consumer classes. However, based on the limited evidence from the literature, residential and commercial class elasticity estimates are usually comparable and industrial class elasticities are typically larger compared to residential and commercial class elasticities. See, for example, [31].

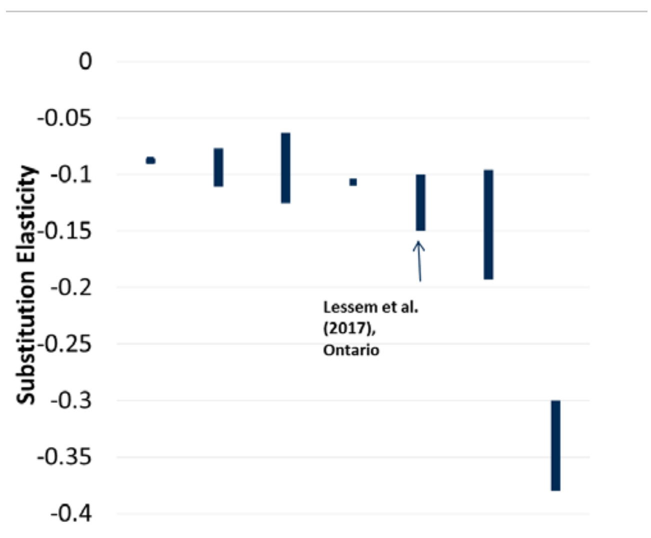
Figure 3: Range of estimates of own-price elasticity for residential and small commercial consumers.



Notes:

1) Based on review of elasticity literature and empirical studies. Each bar indicates the range of elasticities measured in a particular study. [2], [3], [4], [5], [6], [7], [8], [9], [10], [11], [12], [13]
2) ComEd study is singled out in the chart above as it tested real-time prices, most similar to the pricing prototypes analyzed in this study.

Figure 4: Range of estimates of substitution elasticity for residential and small commercial consumers.



Notes:

1) Based on review of elasticity literature and empirical studies. Each bar indicates the range of elasticities measured in a particular study. [2], [3], [4], [5], [6], [7], [8], [9], [10], [11], [12], [13]
2) Ontario study is singled out as it reports elasticities specific to the Ontario region.

Estimating the demand response of each pricing example proceeds in two steps. In step 1, an own-price elasticity of -0.075 is applied to daily consumption. This value of own-price elasticity is based on an estimate of the price elasticity of demand for the consumers of Commonwealth Edison Company (ComEd) in a real-time pricing evaluation study [2]. This study is one of very few rigorous evaluations of customer response to real-time price variations, evaluated for the first large-scale residential real-time pricing program in the United States. It examined whether customers respond to hourly, market-based electricity prices; the magnitude of the effect; and how customers respond to high-price notifications. OEB staff selected the central estimate for own-price elasticity from this study as the setting and rates examined best matched those being evaluated in this study (in particular, hourly time-varying rates), is relatively recent, and has a rigorous methodology with elasticity estimates that are corroborated by other similar studies. In fact, the estimate used may be somewhat conservative relative to that found in other studies.

The price responsive demand is estimated as:

$$Q' = Q \times (1 + E_d \times \%\Delta P)$$

where, for each day,

- E_d is the price elasticity of demand
- $\%\Delta P$ is the percent change in average price
- Q is the original demand
- Q' is the new peak demand.

Based on previous research and the OEB staff consultant's recommendations, it is assumed that the change in demand in any hour will not exceed +15% or −50% and the demand changes are limited accordingly. The choice of using a stricter positive demand cap relative to the negative demand reflects the assumption that consumers may not have the means to increase their consumption significantly when price drastically decreases, but are able to decrease their consumption more significantly when price drastically increases.

In step 2, it is assumed that consumers also use heuristics to plan when to shift load rather than conserve energy within each day. A substitution effect is calculated to quantify the degree to which consumers substitute relatively inexpensive consumption during off-peak periods in each day for relatively more expensive on-peak consumption. The result of this analysis is a class-specific and price-prototype-specific estimate of the amount of electricity consumption that is shifted from on-peak to off-peak hours in each day. For this analysis, OEB staff assumes an elasticity of substitution of -0.11 based on the estimates of this parameter from a recent study of Ontario consumers [6]. In this study, the rollout of TOU rates in Ontario were re-interpreted as a natural experiment and used to study the behaviour of customers before and after being moved to a time-varying rate. While the review of studies from other jurisdictions is helpful, the structure and rigour of the Ontario study, and the fact that it provides Ontario-specific estimates, make it the most reliable source of elasticity of substitution for the purposes of this paper. Notably, this assumption is also well within the range found in studies in other jurisdictions.

To obtain this estimate, within each day, the "on-peak" period is defined separately for RPP and non-RPP consumers as all hours in which the proposed price is greater than the status quo price.[8] This heuristic ensures that substitution within a day will occur from higher-price to lower-priced hours. The Price Response Impact Simulation Model (PRISM) analysis for estimating demand response, developed by The Brattle Group [3], is then applied and the substitution effect is calculated between the on- and off-peak periods based on the average price and demand in those periods as well as the assumed elasticity of substitution.[9] The analytical framework for this PRISM analysis can be found in the original reference [3], the details of which are not required in order to understand the rest of this paper.

This step 2 analysis yields the average level of substitution between on-peak and off-peak periods in each day. To obtain hourly estimates of demand under each proposed prototype, the estimates of substitution are applied to the intermediate demand estimates from step 1. This captures the change in demand from both the own-price elasticity and elasticity of substitution effects (from Steps 1 and 2). The per-period change, relative to original demand, is then applied proportionally to each corresponding hourly demand observation.

The end result of the analysis described in this section is estimates of new (counterfactual) demand profiles for Class B demand under each alternative pricing variant. Next, the economic efficiency of these demand profiles relative to demand under the status quo price is estimated as described in the following section.

2.3 Economic Benefit of Demand Response

The Brattle Group also developed a model to evaluate the relative economic value of each pricing option. This model was used to analyze how economic efficiency would be affected by:

- Changes in system costs induced by the counterfactual demand profiles under each pricing prototype;
- Effects on consumer economic benefit from induced changes in hourly demand.

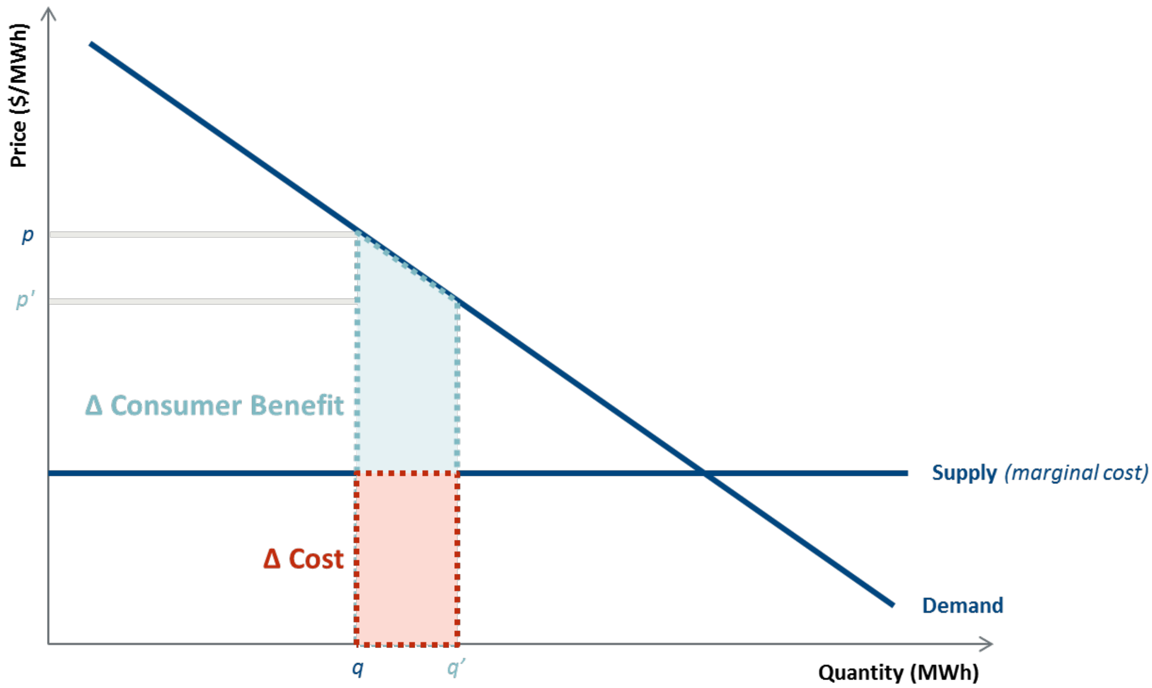
A full view of system-wide economic impacts must include not only changes in electricity system costs but also the consumer benefit impacts caused by hourly increases or decreases in electricity prices and class-wide demand.

In Figure 5, a schematic illustration of the methodology is provided. Suppose that the price in a given time period (say, one hour) decreases from *p* to *p'*, causing the quantity demanded to increase from *q* to *q'*. In this given time period, decreasing price and increasing quantity demanded will increase production costs. However, it will also increase gross consumer benefits measured as the area under the demand curve. Added to this is the system cost of the change in demand to arrive at the total welfare. Whether the total welfare is positive or negative from a holistic perspective (still considering only this time period) depends on the level of prices relative to the marginal cost. If prices are above marginal cost, as they are in this example and during many hours in Ontario, the total welfare of lowering prices will be positive.

[8] This varies across the consumer classes as prices are different under the status quo. In outlier cases when the proposed price is greater than the status quo price in all hours of the day or the proposed price is less than the status quo price in all hours, the on-peak period is assumed to be between hour 8 and hour 19, inclusive.

[9] If the average price in both periods is negative, no substitution is assumed. If the average price in the off-peak period is negative, 15% of the on-peak demand is assumed to be shifted to the off-peak period. If the average price in the on-peak period is negative, the on-peak demand is assumed to increase by 15%, and that amount is removed from the off-peak demand. These assumptions ensure the model is tractable under outlier cases of the many potential price patterns observed in the status quo and prototype pricing profiles.

Figure 5: Economic efficiency from a total welfare perspective.



The net system wide impact of each pricing prototype is the sum of the change in gross consumer benefit impact and the change in system costs. The methodology for estimating each of these two components is described below.

The following system cost components were considered for inclusion in the estimate of avoided system cost impact:

1. Energy costs;
2. Generation capacity costs;
3. Ancillary services costs;
4. Transmission and distribution capacity costs.

This analysis assumes other cost components do not vary with system load. The considered cost components reflect the recommendations in a recent report by The Brattle Group authors on best practices for valuing demand response [14]. However, for the reasons described below, neither ancillary service costs nor transmission and distribution capacity costs are included in the resulting analysis.

2.3.1 Energy Costs

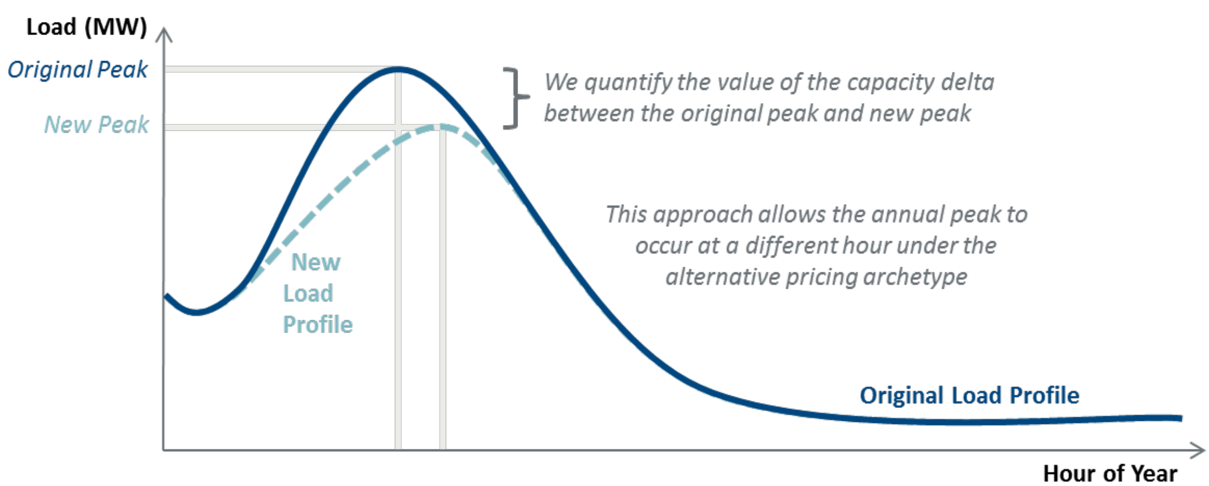
For each pricing variant tested, the annual energy cost savings are modelled assuming that any increase or decrease in hourly system load are valued at the marginal cost of energy in that hour as determined by the HOEP. In particular, in each hour, the difference between the estimated class B load under a given pricing option and class B load under the status quo prices is calculated. The change in system cost is then calculated to be the product of the change in load (in MWh) and the HOEP in the same hour (in $/MWh). It is assumed that the HOEP reflects the relevant marginal cost of energy in each hour. Annual energy cost savings under a given pricing option are calculated as the sum of the hourly changes in energy costs. These cost savings accrue to all Ontario consumers.

This methodology assumes that any changes in class B load comprise a small enough share of system load that the marginal cost of energy is not affected by the pricing prototype.

2.3.2 Generation Capacity Costs

The changes in generation capacity costs for each pricing prototype are calculated on an annual basis. In each year, the counterfactual annual (single hour) system-wide peak demand under each prototype is determined and compared to the peak demand under the status quo; see Figure 6. The difference in peak demand is multiplied by an assumed reserve requirement of 20 percent[10] to estimate the resource requirement (in unforced capacity, or UCAP, terms) associated with the change in peak demand. This value (in MW) is multiplied by an assumed value of capacity (in \$/MW-year) to obtain the generation capacity cost savings in each year. These cost savings accrue to all Ontario consumers. Note that any induced change in the proportion of GA paid by class A and class B consumers due to this change in peak demand is not taken into account in this analysis.

Figure 6: Schematic of approach for estimating capacity savings under alternative pricing prototypes.



It is assumed that the value of generation capacity savings changes over time, as follows:

- In 2018, the first year of this analysis, the marginal value of capacity reductions is zero as the Ontario system has sufficient capacity and incremental reductions in peak demand do not reduce capacity costs
- In 2022 and later years, it is estimated that the value of capacity will be \$143,531/MW-year in 2021 Canadian dollars, and rising with inflation.[11]

[10] This is consistent with the implied reserve requirement in the 2016 Ontario Planning Outlook, based on data from Figures 9 and 13a in that document. See [30].
[11] This is based on an OEB staff estimate of the value of capacity in 2022. The estimate is an intermediate value, inflated to 2022 dollars, sourced from the IESO's assessment of the need for the East-West Tie expansion [32]. Specifically, the value used is intermediate between approximate clearing

- In 2019 through 2021, it is assumed that the value of capacity increases linearly from the 2018 to the 2022 values. This reflects some uncertainty in when the capacity constraint may become binding in Ontario; depending on the demand outlook used, there could be a capacity shortfall as early as 2021 or as late as 2023 [15]. In addition, even if the reserve requirement is exceeded in these years, there could still be some non-zero value of capacity due to incrementally lower loss of load probability. The linear trajectory of assumed capacity values in these years constitutes a simplifying assumption to attempt to capture these uncertainties.

The resulting schedule of the value of avoided capacity is shown in Table 25.

2.3.3 Ancillary Services Costs

The IESO contracts for four ancillary services, including regulation service, reactive support and voltage control, reliability must-run, and black start. Of these, it is assumed that only regulation service can vary as a function of system load; reactive support and voltage control are generally procured in response to localized system conditions in a way that does not directly depend on aggregate system load; quantities of black start necessary for the system do not depend on system conditions; and reliability must-run is not currently procured.

To calculate the change in regulation service costs under each prototype, the simplifying assumption is made that the quantity of regulation procured in each hour is proportional to system load. Under this assumption, the marginal cost of regulation service is equal to the average cost and is calculated as the annual regulation service cost ($) divided by annual system load (MWh). Thus, in any hour, the change in regulation service cost is calculated as the product of the change in load under a given pricing prototype (in MWh) and the marginal cost of regulation service in (in $/MWh). The value of the annual cost of regulation service can be estimated as the average of the 2015 and 2016 costs published by the IESO.[12] For each year after 2016, it is assumed that regulation service costs grow with inflation.[13]

The resulting value of ancillary services cost impacts, $0.3/MWh in 2015 and 2016, are significantly smaller than other system cost components. As a result, the ancillary services cost impact is omitted from the estimation of system cost impacts.

2.3.4 Transmission and Distribution Capacity Costs

The impact on transmission and distribution costs due to a change in electricity consumption is highly dependent on the conditions and infrastructure of the system in question. The forecast of planned transmission projects in the 2017 Long Term Energy Plan [16] indicates no substantial transmission network investment to be avoided by an overall decrease in province-wide peak demand.[14] Avoided costs from reduced transmission connection costs or deferred investment at

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prices in the IESO Demand Response auction ($80,000/MW-yr, nominal $) and the estimated cost of building new capacity ($180,000/MW-yr, nominal $).

[12] 2017 regulation service costs were not yet available as of the time of this analysis. 2015 and 2016 costs given by: IESO, "Ancillary Services Market." Available at: http://www.ieso.ca/sector-participants/market-operations/markets-and-related-programs/ancillary-services-market

[13] Here and in other instances later, an inflation rate of 2 percent per year is assumed.

[14] The Long Term Energy Plan 2017 (LTEP 2017) [16] builds on the resource planning outlooks created by the IESO and states that "…there will be no need for any major expansion of the province's transmission system beyond the projects already planned or under development." Major projects that are under development are responsive to local or regional needs reflecting long-standing transmission constraints, local load growth, or needs to upgrade and replace existing infrastructure. The same is true of the regional projects covered in the LTEP 2017, Chapter 8. The needs for these

the distribution level are beyond the scope of the analysis in this paper. For these reasons, transmission and distribution cost impacts are omitted from the estimation of system cost impacts.

2.3.5 Consumer Benefit

The second component of the net system-wide economic efficiency that would be affected by changes to class B electricity prices is consumer benefit. Just as a new price for a given hour will result in a system cost saving or expense, it will also result in an incremental benefit or loss for consumers. This reflects the value businesses derive from using electricity as an input into their processes for producing goods and services. It also reflects the value residential consumers derive from using electricity to power their home appliances. Estimating these incremental consumer benefits or losses requires resort to economic theory. The discussion below illustrates this.

It is assumed that consumer benefit for a given level of quantity demanded in a given time period can be calculated as the integral of the demand curve over the full range of quantity demanded.[15] This integral represents the sum of the value that consumers receive for each incremental unit of electricity consumption between the first and the last MWh in each hour.

Under this framework, the change in consumer benefit induced by a given price prototype, relative to the status quo price, is given by the integral of the demand curve between the original quantity *q* and the new quantity *q'* (see Figure 5). This integral is estimated by approximating the demand curve as linear in the region of the price and quantity change; such an approximation is accurate for very small movements along the curve but will be less accurate for very large changes in price and quantity.

Under this approximation, the change in consumer benefit is equal to:

$$\Delta\text{Benefit} = \frac{1}{2}(p + p') \cdot (q' - q)$$

This methodology is applied to calculate the change in benefit induced by price changes in each of the on-peak and off-peak periods in each day of each year of the analysis. The change in consumer benefit is calculated at the daily period level because calculations at the hourly level would be inconsistent with the structure that was used for calculating consumer substitution in the elasticity calculation described in section 2.2. Daily consumer benefit effects are calculated as the sum of the on-peak and off-peak effects and annual consumer benefit effects are calculated as the sum of benefit effects across all days in the year.

2.4 Statistical Analysis of Consumer Bill Impact

The analysis described above examines the economic efficiency of each pricing prototype as it applies to class B consumers collectively. The actual change in the cost of electricity as a result

projects are not driven by changes in province-wide peak demands and therefore, in OEB staff's view, transmission investment is unlikely to be affected by the peak demand impacts modelled in this study.

15 This yields gross consumer benefit (i.e., not net of consumer costs or system costs). Further, it should be noted that, in energy markets where energy producers are paid the same price as is charged to consumers, this area under the demand curve also represents a change in gross benefits to energy producers. However, in Ontario, where almost all electricity generation receives a guaranteed fixed price or is guaranteed fixed revenue amounts, the vast majority of the value represented by the area under the demand curve accrues to consumers. For this reason, this quantity is referred to simply as the "consumer benefit" rather than the "consumer and producer benefit."

of applying each pricing prototype will, however, vary for each consumer depending on the specific nature of their electricity consumption and how much they change their consumption in response to the new prices.

To quantify the range of electricity cost impacts expected to result from each pricing prototype, a collection of historical hourly electricity consumption profiles for 6,940 General Service consumers with an average monthly peak demand between 50 kW and 999 kW (GS 50 – 999 kW) is utilized. A summary of this collection of profiles is provided in Appendix C.

The profiles range from the years 2012 to 2015. In order to calculate the electricity (also called commodity) cost impacts of each of the pricing variants under consideration, it is necessary to construct each variant based on historical data rather than using forecast data as is described in the sections above. In this way, the hypothetical cost impact of what each consumer would have paid relative to what they actually paid is being calculated. All of the inputs for each of the pricing prototypes – namely hourly Ontario demand, HOEP and GA costs – are available publicly so such historical pricing profiles can be created in the same way as described in Appendix A. The one exception is that of the supply-shaped prototype for which detailed GA cost information for different technologies is also required. For this reason, the supply-shaped variants have been omitted from the consumer bill impact analysis.

For each pricing option under consideration and for each consumer profile, the expected change in annual electricity cost relative to the cost under status quo pricing is calculated for two scenarios:

- No Response Scenario. The change in electricity cost due to the new price is calculated assuming each consumer does not change their consumption behaviour.
- Demand Response Scenario. The change in electricity cost due to the new prices is calculated assuming each consumer changes their consumption behaviour based on the elasticity model described in section 2.2.

Note that this calculation does not take into account any of the avoided system costs that may be induced by a change in demand induced by the change in price, which would, in principle, accrue to all electricity consumers. The calculation focuses only on the direct individual impacts of a change in electricity price.

This collection of cost impacts provides an indication of the range of impacts that General Service consumers may experience from each pricing prototype. However, the dataset was not collected for the purpose of this analysis and should not necessarily be considered representative of the broader General Service consumer population. The OEB is in the process of gathering a more representative sample for further analysis.

3 Results of Analysis

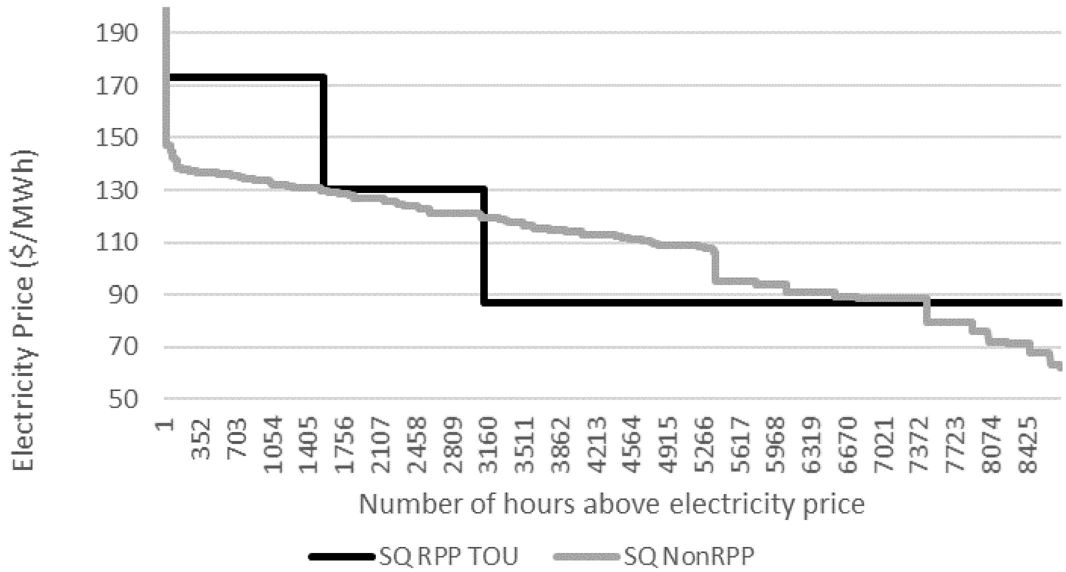
This section presents the results of the economic efficiency analysis of the pricing prototypes introduced in section 2. The subsections below are each devoted to one of the pricing prototypes under consideration. In each, the prototype is briefly described (full definitions of each prototype are provided in Appendix A), specific variants of that prototype are defined and the estimated demand response, avoided cost, consumer benefit and total welfare over the forecast period for each example are presented. Additionally, the distribution of electricity cost impacts for roughly 7,000 historical demand profiles described in section 2.4 is presented. The implication of these results and the larger lessons to be learned from them are presented in section 4.

3.1 Status Quo Price

The status quo pricing profile is a simplified version of the class B pricing in place in 2018 and is used as a baseline against which all other pricing profiles are compared for the purposes of estimating demand response impact. Class B consumers are divided into two groups: those on the RPP and all other consumers, called non-RPP class B consumers. RPP consumers are modelled to pay TOU in a similar fashion to that currently defined for RPP consumers, while non-RPP consumers are modelled to pay HOEP plus a flat monthly GA price that changes month-to-month. For the sake of simplicity, neither tiered RPP pricing nor retail rate contracts are included in this analysis. The status quo prices, similar to all other pricing prototypes, are defined relative to data over the forecast period 2018-2031 and so will differ from actual prices experienced in reality.

The price duration curve of each status quo price in a representative year is shown in Figure 7. This graph shows the number of hours at which the price is above the indicated value and thus describes the frequency of prices over the year. In each subsection below, the price duration curve for each prototype variant is presented relative to these reference status quo price duration curves.

Figure 7: Price duration curve of status quo pricing profile for calendar year 2018. The SQ NonRPP curve reaches a maximum of $687/MWh for a single hour on the far left of the horizontal axis.



The status quo prices, as defined above, serves as the baseline against which all other pricing prototypes are compared. It is the difference between each pricing prototype and the status quo price that determines the estimated demand response for each prototype and the subsequent evaluation of total welfare.

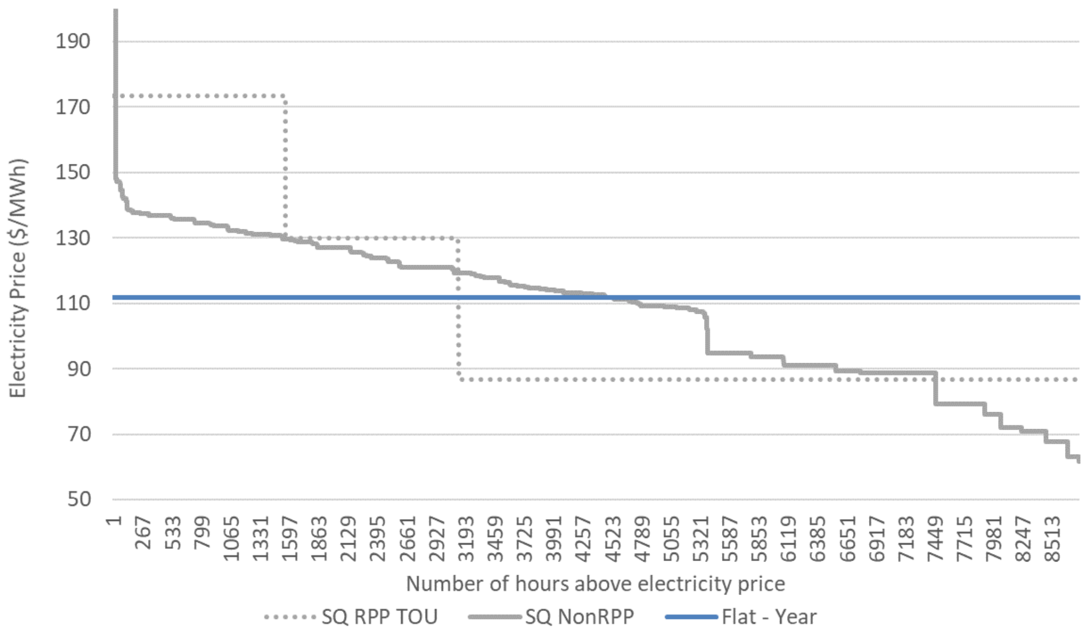
3.2 Flat Price

The flat pricing profile is defined to be the least dynamic prototype, charging consumers the same price in all hours so as to recover all market and GA costs over the cost recovery period. As with all other pricing options examined, an annual cost recovery period is chosen that aligns with each calendar year over the forecast period.

Table 2: Variants of the flat price prototype.

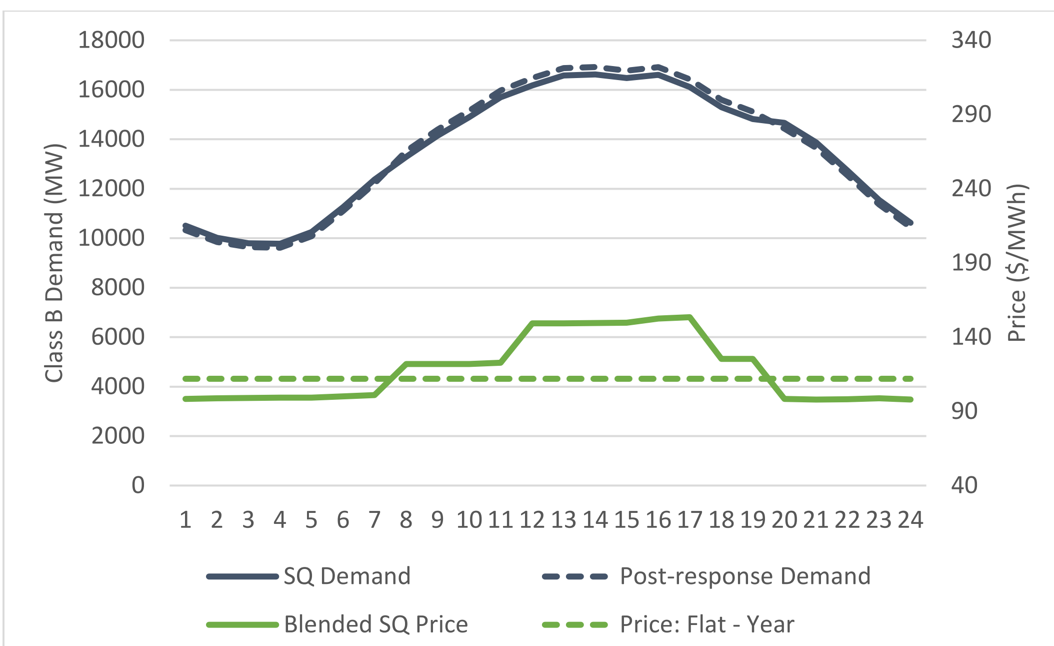
Reference	Pricing prototype	Description	Adjustable Parameters
Flat	Flat	Same price in all hours over the cost recovery period	Cost recovery period is each calendar year

Figure 8: Price duration curve for the flat pricing prototype in calendar year 2018.



3.2.1 Demand Response

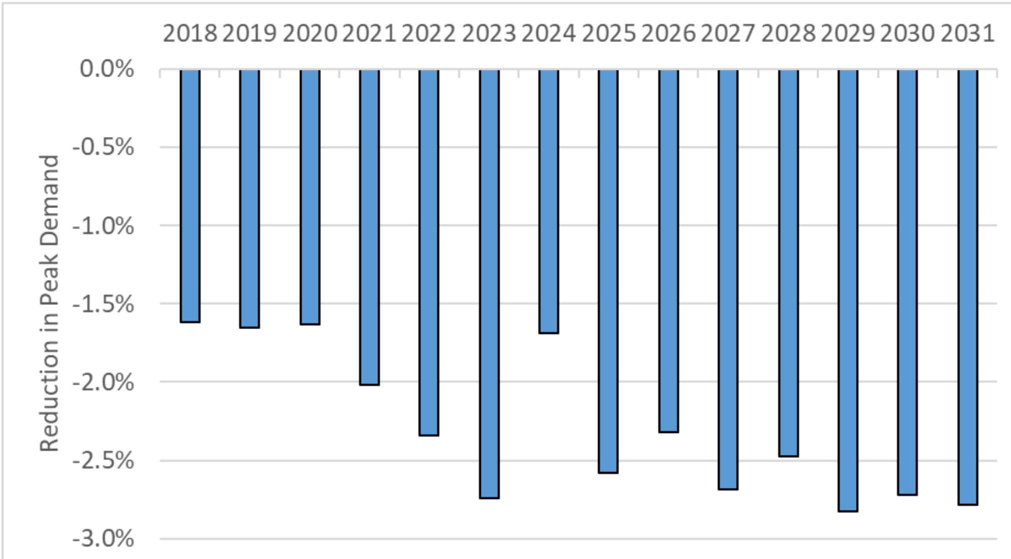
Figure 9: Example of prices[16] and class B demand response in the flat price variant on a simulated hot summer day.



[16] The "Blended SQ Price" is a weighted average of the SQ RPP TOU and SQ NonRPP prices.

The horizontal axis indicates the hour in the day.

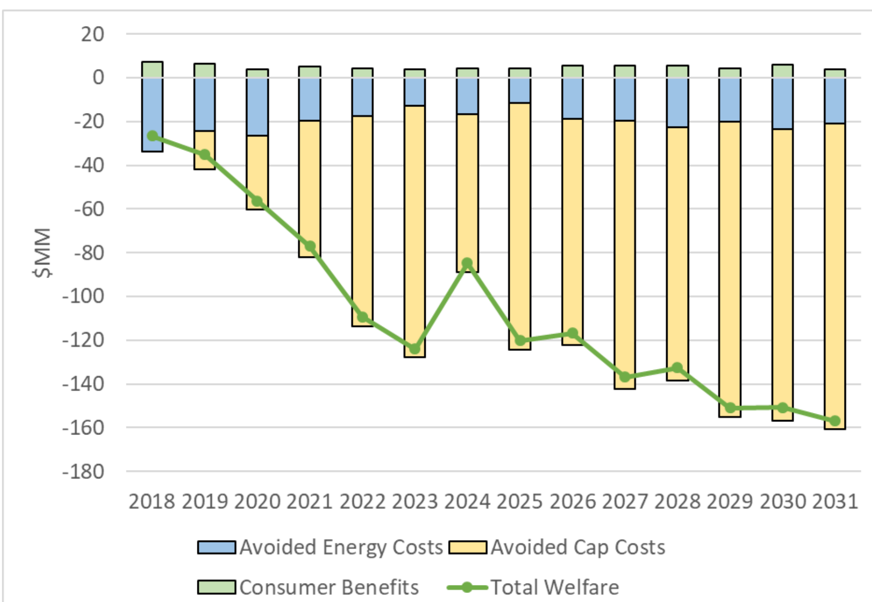
Figure 10: Annual reduction in peak demand for the flat price variant.



Note that a negative reduction in peak demand indicates an increase in peak demand.

3.2.2 Avoided Costs, Consumer Benefit and Total Welfare

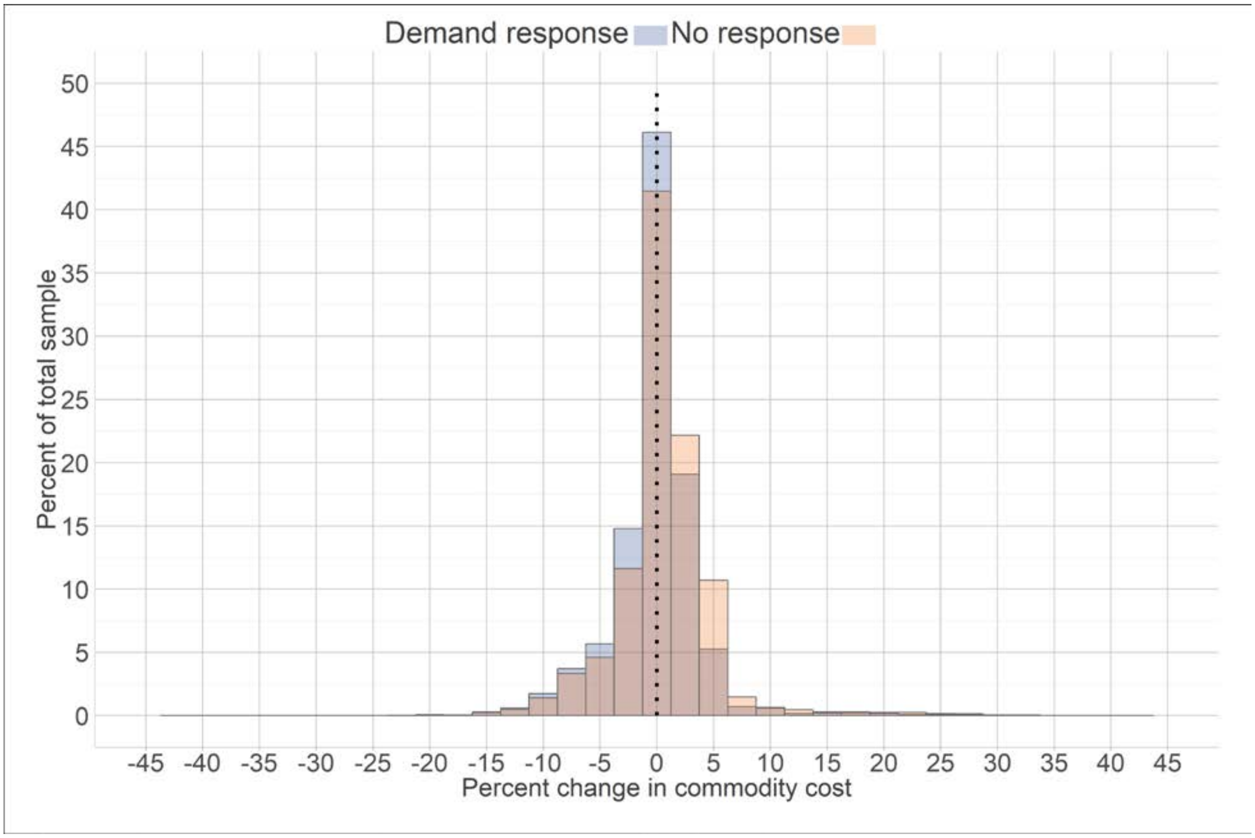
Figure 11: Avoided cost, consumer benefit and total welfare in the Flat Price variant.



With modest negative avoided costs (*i.e.*, added system cost) and little consumer benefit, the flat pricing prototype exhibits negative total welfare across the forecast period. The flat pricing prototype is the least dynamic of all prototypes under consideration and so is the least responsive to both consumer and system needs. However, given the relatively small difference between status quo prices and flat pricing, the demand impacts are modest and thus the negative total welfare is also modest compared to other examples under consideration below.

3.2.3 Distribution of Consumer Cost Impacts

Figure 12: Consumer impact distribution for the Flat price variant.



The width of each bar represents a 2.5% change in commodity costs. The demand response scenario assumes consumers adapt their hourly demand to the new prices. The no response scenario assumes no change in consumer demand in response to new prices.

Response Type	Percentage of Customers that Experience a Cost Decrease	Percentage of Customers that Experience a Cost Increase
No response	39	61
Demand response	51	49

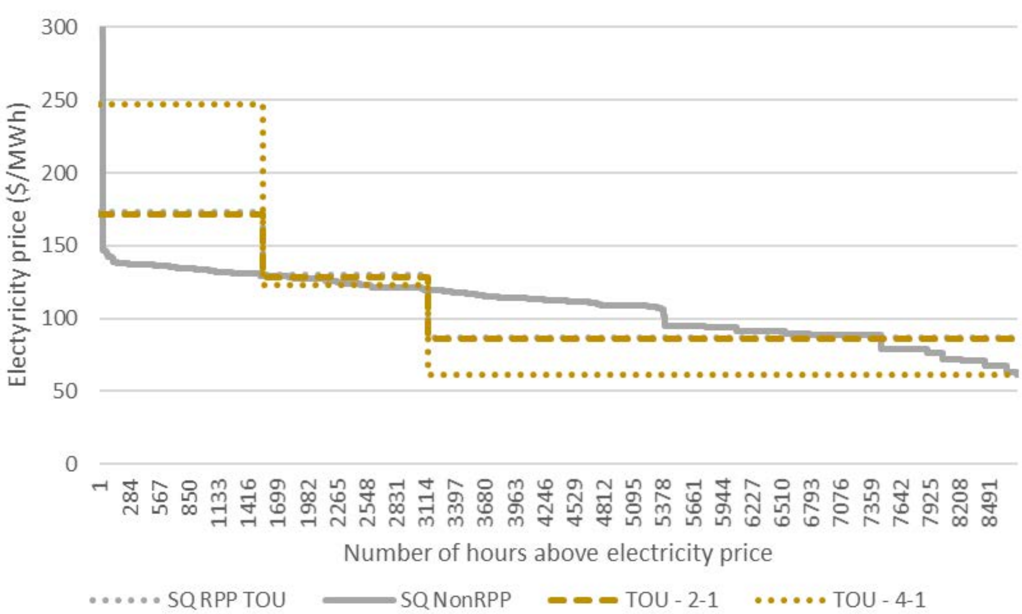
3.3 TOU Price

The TOU pricing prototype is a natural extension of the status quo RPP price but applied to all class B consumers. It allocates the sum of all market and GA costs over the cost recovery period. While the cost recovery period as well as the periods in which low, mid and high prices are applied can be defined in a wide variety of ways, for the purposes of this analysis an annual cost recovery period (calendar year) is defined and the low, mid and high price periods are prescribed to align with the off-, mid- and on-peak RPP periods as shown in Figure 48 (see Appendix A for details). In this way, the examples of TOU pricing studied are straightforward extensions of the current RPP TOU pricing. However, the impact of modifying the ratio between the low, mid and high prices is examined.

Table 3: Variants of the TOU prototype.

Reference	Pricing prototype	Description	Adjustable Parameters
TOU - 2-1	Time of Use	On-to-off peak ratio of 2:1	RPP TOU periods, 2:1 on-off peak price ratio, annual cost recovery period
TOU - 4-1	Time of Use	On-to-off peak ratio of 4:1	RPP TOU periods, 4:1 on-off peak price ratio, annual cost recovery period

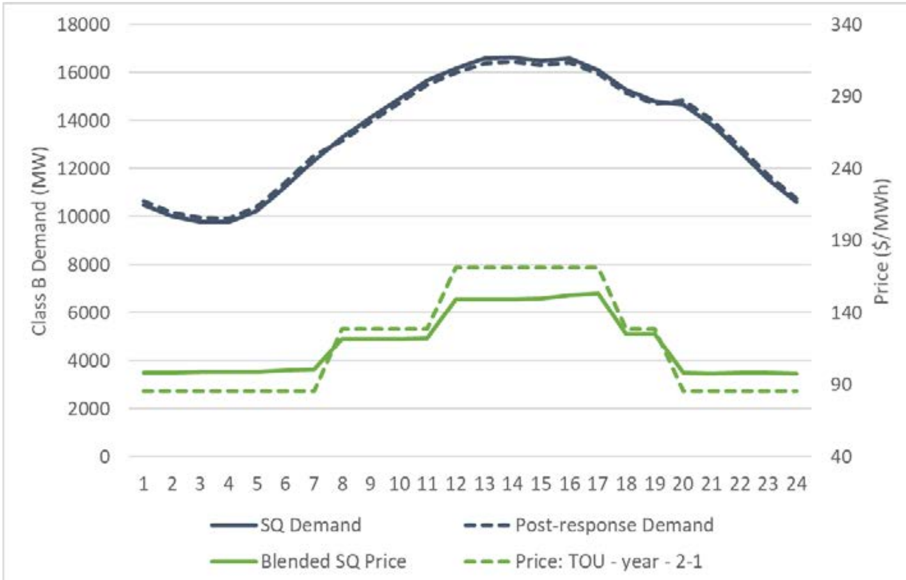
Figure 13: Price duration curve for variants of the TOU pricing prototype for calendar year 2018.



The distribution of prices in the expanded TOU pricing prototype follows the same distribution in time as the SQ RPP TOU prices since each uses the same price periods. The value of the prices in each period, however, does vary across variants.

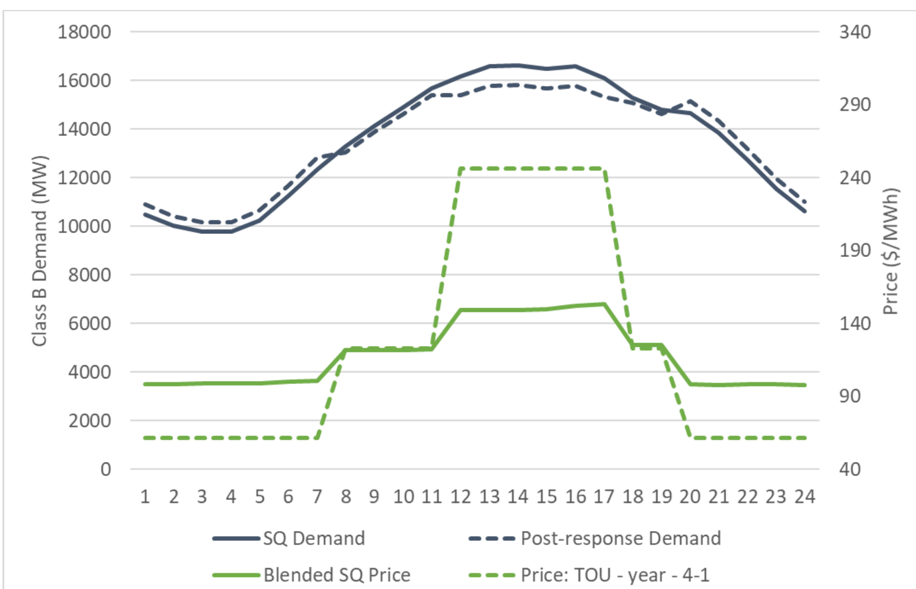
3.3.1 Demand Response

Figure 14: Example of prices and class B demand response in the TOU - 2-1 variant on a simulated hot summer day.



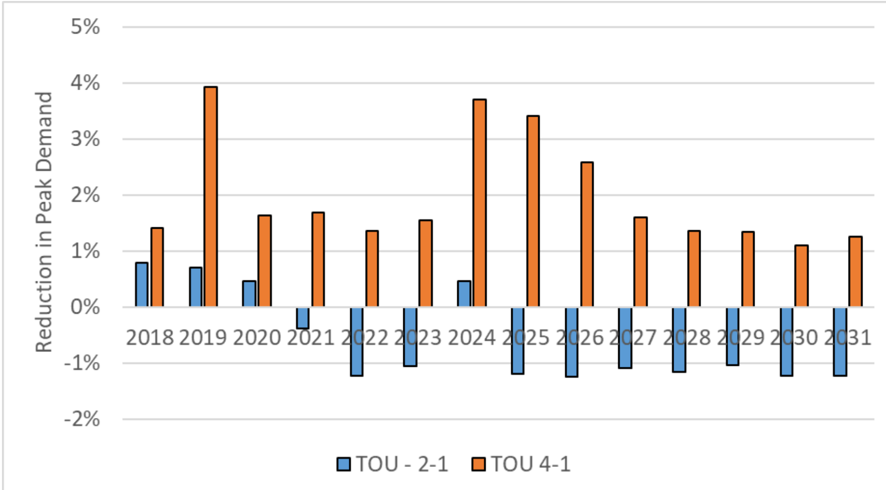
The horizontal axis indicates the hour in the day.

Figure 15: Example of prices and class B demand response in the TOU - 4-1 variant on a simulated hot summer day.



The horizontal axis indicates the hour in the day.

Figure 16: Annual reduction in peak demand for the TOU pricing variants.



The expanded TOU pricing prototype was designed as a straightforward extension of current RPP TOU pricing applied to all class B consumers, maintaining the current time periods of on-, mid- and off-peak pricing as shown in Figure 48. In the "TOU – 2-1" example, the primary difference between status quo pricing and the TOU 2-1 pricing variant is the extension of TOU prices to non-RPP consumers. Status quo non-RPP consumers pay the HOEP plus a flat GA price that is the same in all hours of a month. In this TOU 2-1 variant, whether or not non-RPP consumers change their demand during the Ontario peak demand hour will depend on the value of HOEP in that hour.

Some unintuitive changes in predicted demand within the TOU 2-1 analysis warrant further discussion. In most years throughout the forecast period, HOEP is approximately $150/MWh or more during the hour of peak demand, resulting in status quo non-RPP prices during peak hours of more than $220/MWh. This is higher than the proposed TOU 2-1 on-peak price of approximately $180/MWh, so in most years, non-RPP consumers are incented by the TOU 2-1 prices to *increase* their consumption during peak demand hours. This is the primary cause of the increase in peak demand for the TOU 2-1 pricing variant in most years shown in Figure 16. The exception to this trend is in 2024, where HOEP is $55/MWh in the peak demand hour, resulting in a status quo non-RPP price of $133/MWh. This is lower than the proposed TOU 2-1 price of $186/MWh, so in 2024, non-RPP consumers are incented to reduce their consumption during peak demand. The same behaviour is seen in forecast years 2018-2020 as well.

On the other hand, in the TOU 4-1 price variant, the proposed on-peak price is always higher than the status quo non-RPP price during peak demand hours and, thus, there is a reduction in peak demand in all years.

3.3.2 Avoided Costs, Consumer Benefit and Total Welfare

Figure 17: Avoided cost, consumer benefit and total welfare in the TOU - 2-1 pricing variant.

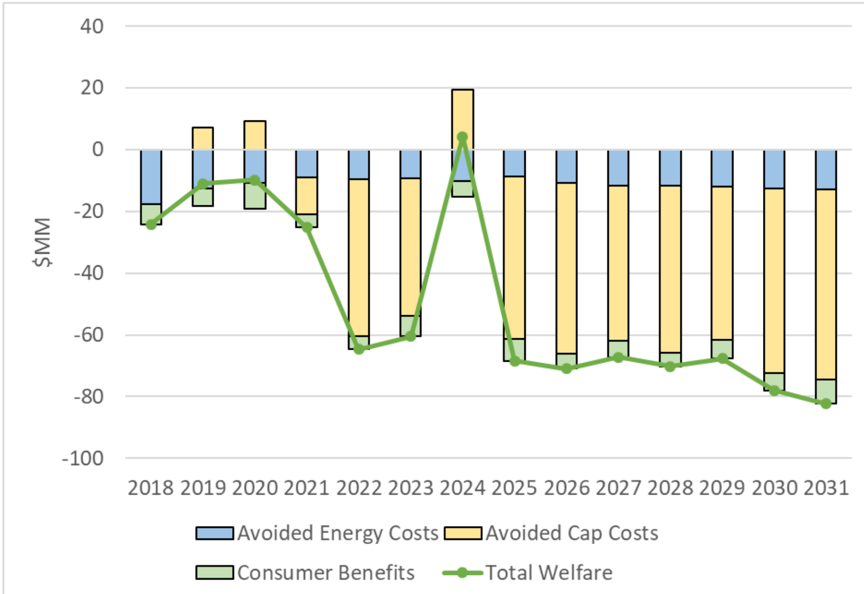
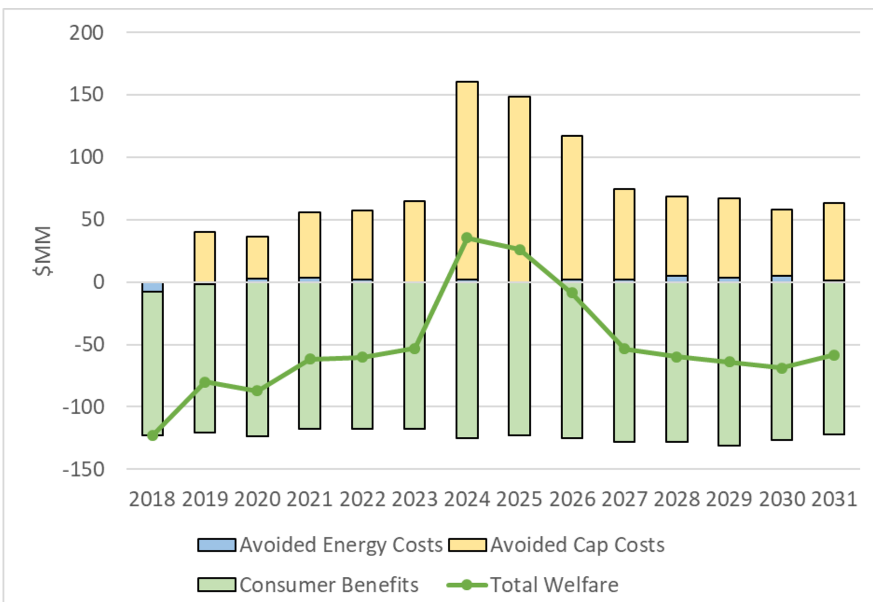
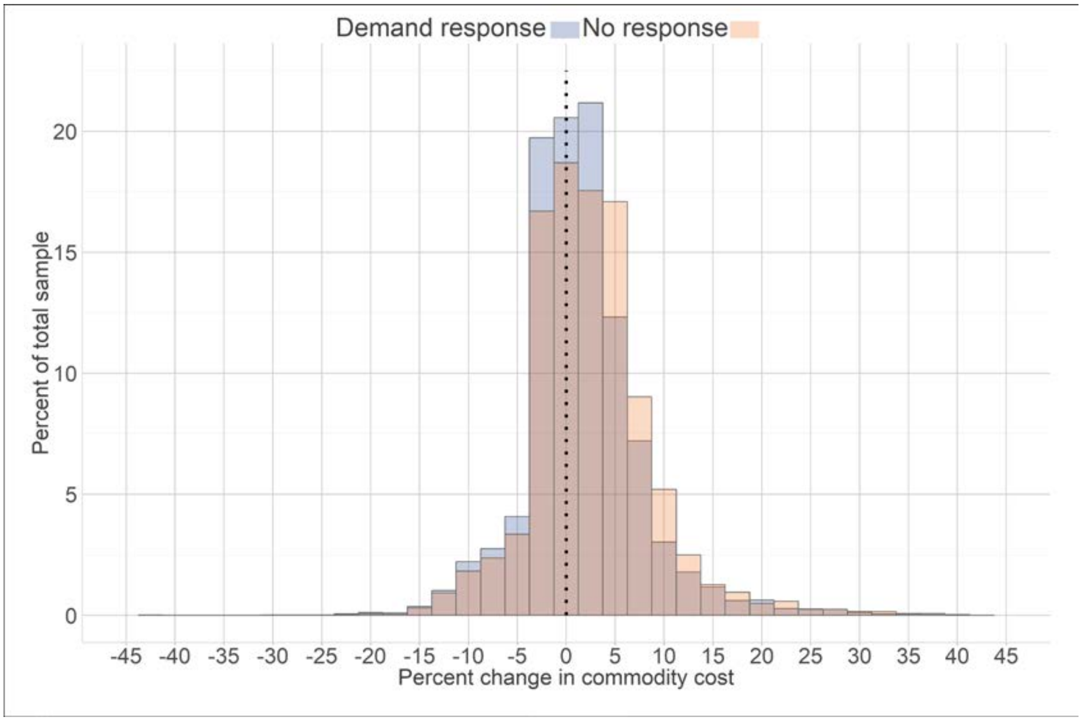


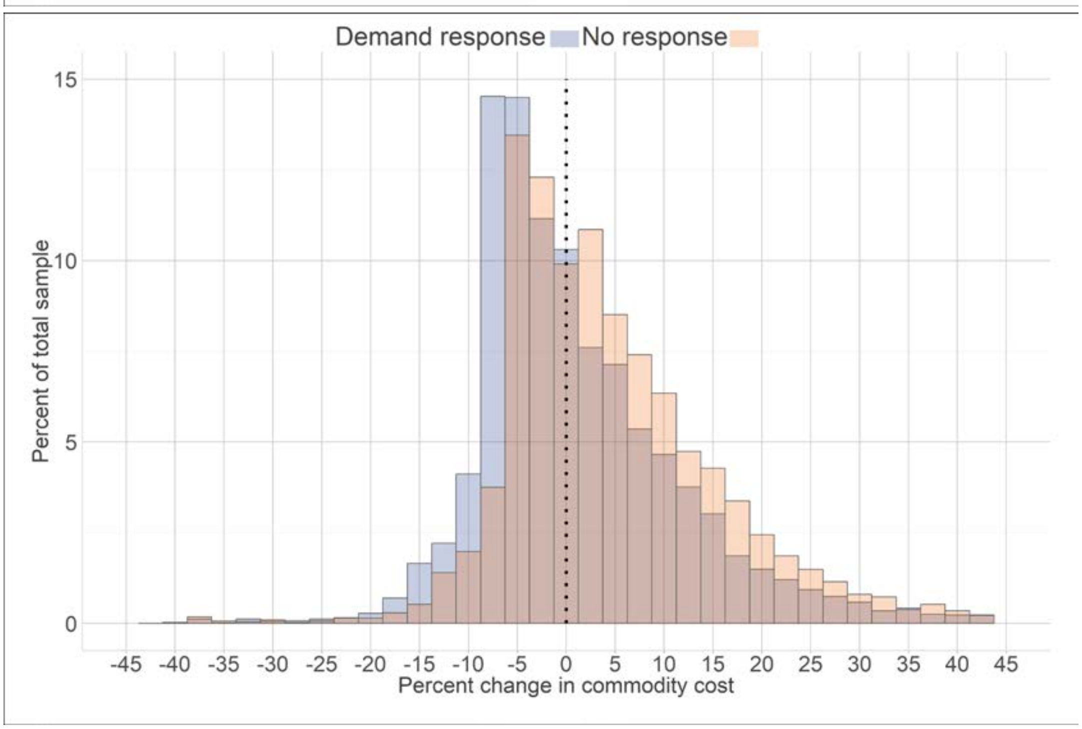
Figure 18: Avoided cost, consumer benefit and total welfare in the TOU - 4-1 pricing variant.



3.3.3 Distribution of Consumer Cost Impacts

Figure 19: Consumer impact distribution for the TOU - 2-1 (top) and TOU - 4-1 (bottom) price variant.





The width of each bar represents a 2.5% change in commodity costs. The demand response scenario assumes consumers adapt their hourly demand to the new prices. The no response scenario assumes no change in consumer demand in response to new prices.

Prototype	Response Type	Percentage of Customers that Experience a Cost Decrease	Percentage of Customers that Experience a Cost Increase
TOU (2:1)	No response Demand response	36 41	64 59
TOU (4:1)	No response Demand response	39 54	61 46

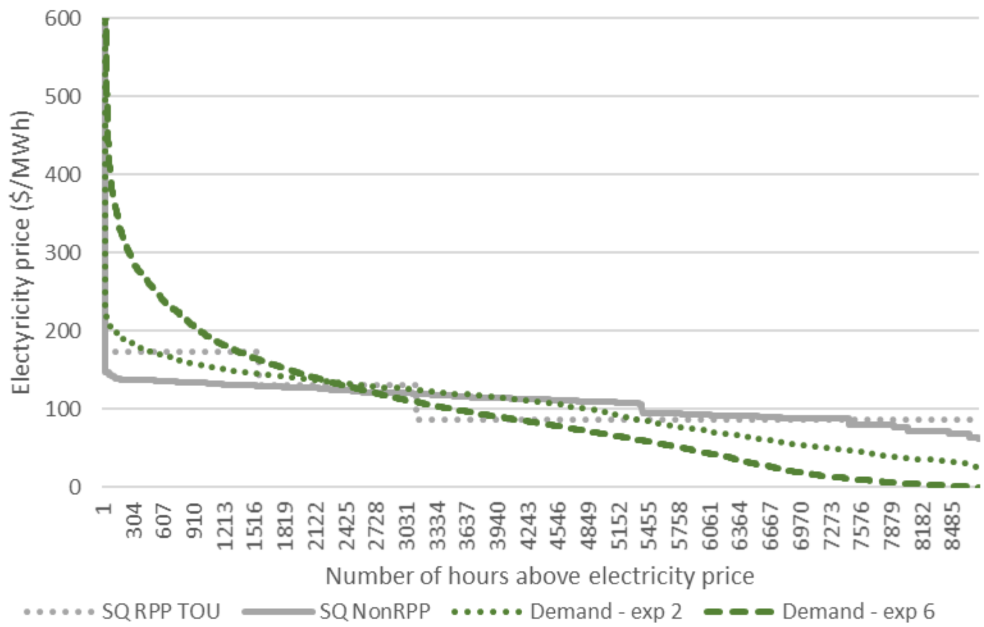
3.4 Demand-Shaped Price

The demand-shaped pricing prototype is designed so that class B GA costs are recovered in a fashion that is directly correlated with total Ontario demand in each hour. That is, prices are high when demand is high, and prices are low when demand is low. The degree to which prices change relative to demand is determined by the “demand exponent,” the value of which determines whether the price fluctuates a lot (large value of the demand exponent) or a little (low value of the demand exponent) between periods of high demand and low demand. See Appendix A for the precise definition. The impact of such a pricing system is examined using two examples exhibiting a small and a large range of prices, respectively, between periods of low and high demand.

Table 4: Variants of the demand-shaped prototype.

Reference	Pricing prototype	Description	Adjustable Parameters
Demand - exp2	Demand-shaped	HOEP + hourly GA price weakly correlated with Ontario demand	Demand exponent $w = 2$
Demand- exp6	Demand-shaped	HOEP + hourly GA price strongly correlated with Ontario demand	Demand exponent $w = 6$

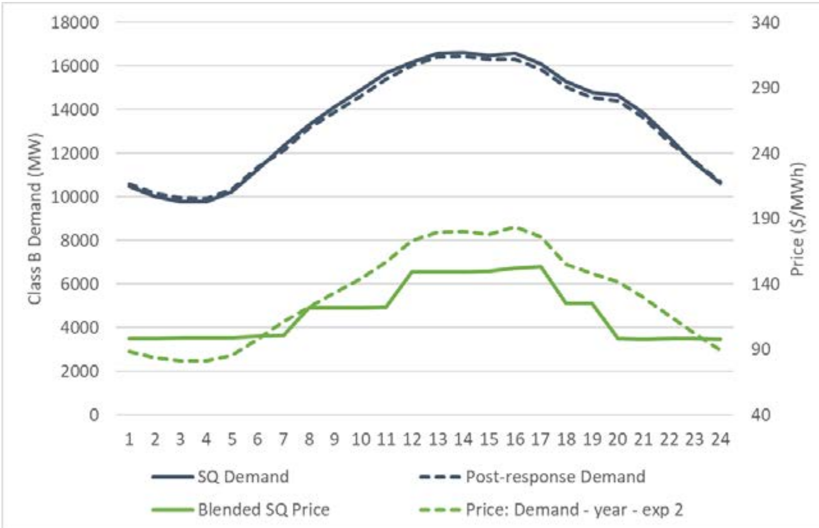
Figure 20: Price duration curve for variants of the demand-shaped pricing prototype for calendar year 2018.



The price duration curve shows the higher prices exhibited by the “exp 6” variant relative to the “exp 2” variant on the left side of the plot, along with lower prices in the “exp 6” variant on the right hand side. The price range is much larger in the “exp 6” variant, with higher prices in periods of high demand and lower prices in periods of low demand relative to the “exp 2” variant.

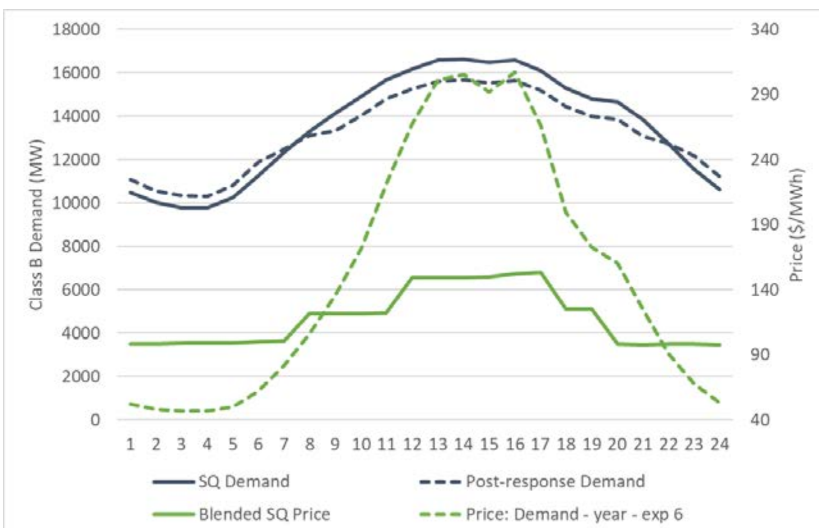
3.4.1 Demand Response

Figure 21: Example of prices and class B demand response in the Demand – exp 2 variant on a simulated hot summer day.



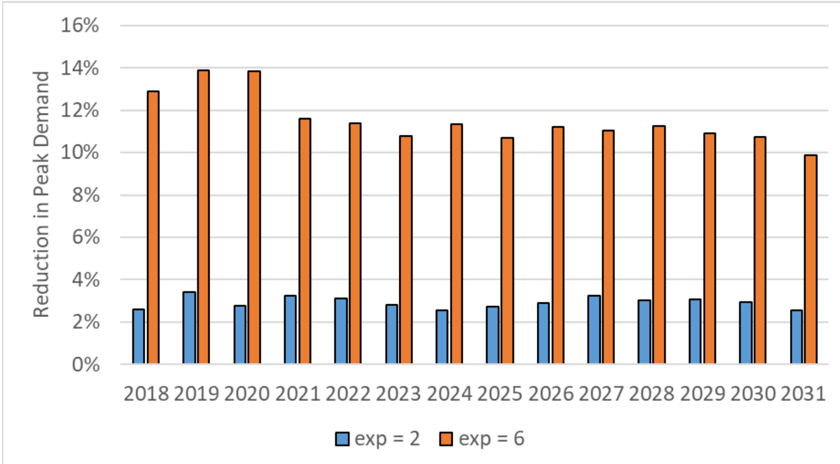
The horizontal axis indicates the hour in the day.

Figure 22: Example of prices and class B demand response in the Demand – exp 6 variant on a simulated hot summer day.



The horizontal axis indicates the hour in the day.

Figure 23: Annual reduction in peak demand for the demand-shaped pricing variants.



3.4.2 Avoided Costs, Consumer Benefit and Total Welfare

Figure 24: Avoided cost, consumer benefit and total welfare in the Demand - exp 2 pricing variant.

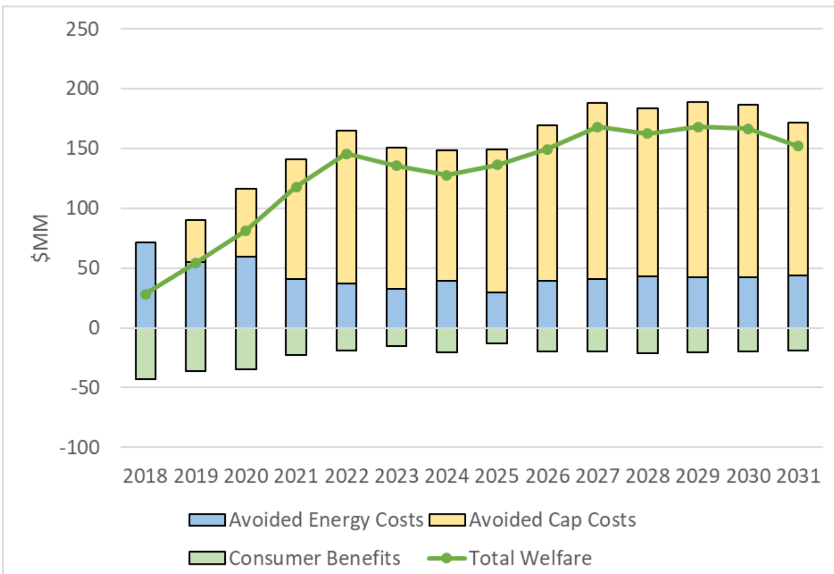
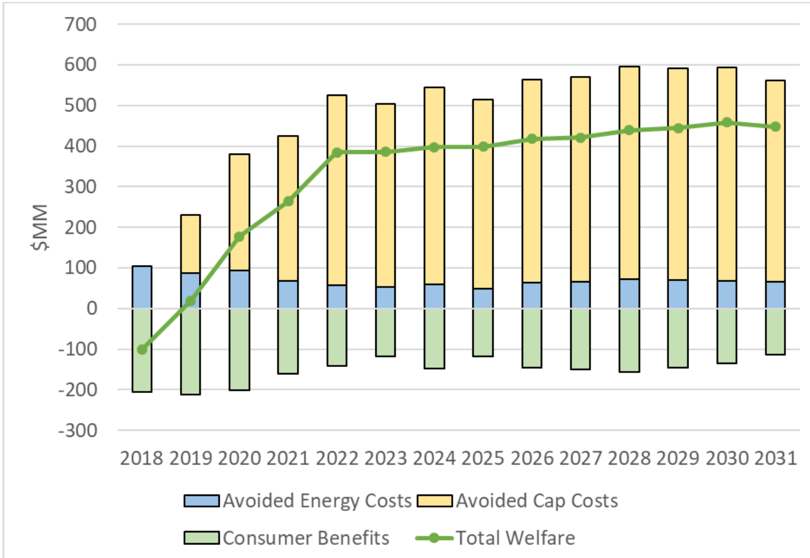


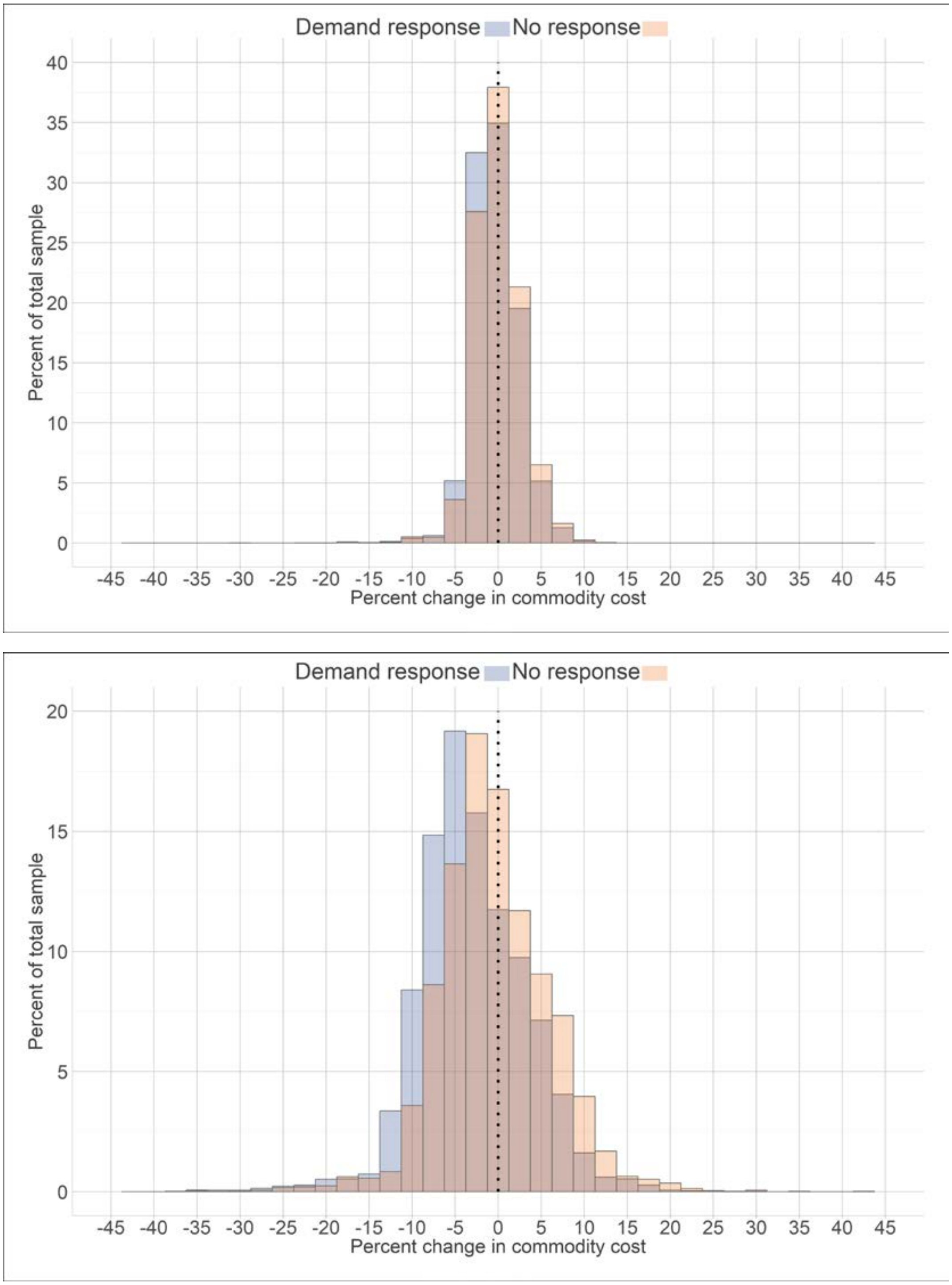
Figure 25: Avoided cost, consumer benefit and total welfare in the Demand – exp 6 pricing variant.



In both examples of the demand-shaped pricing prototype it is seen that positive avoided costs are combined with negative consumer benefits, both of which grow as the strength of the correlation between price and demand rises. The avoided costs are greater than the negative consumer benefits leading to positive total welfare in most years over the forecast period. This total welfare gain increases dramatically through 2022, primarily driven by substantial growth in the assumed value of capacity.

3.4.3 Distribution of Consumer Cost Impacts

Figure 26: Consumer impact distribution for the Demand – exp 2 (top) and Demand – exp 6 (bottom) price variants.



The width of each bar represents a 2.5% change in commodity costs. The demand response scenario assumes consumers adapt their hourly demand to the new prices. The no response scenario assumes no change in consumer demand in response to new prices.

Prototype	Response Type	Percentage of Customers that Experience a Cost Decrease	Percentage of Customers that Experience a Cost Increase
Demand - exp 2	No response	55	45
	Demand response	59	41
Demand - exp 6	No response	56	44
	Demand response	70	30

3.5 Supply-Shaped Price

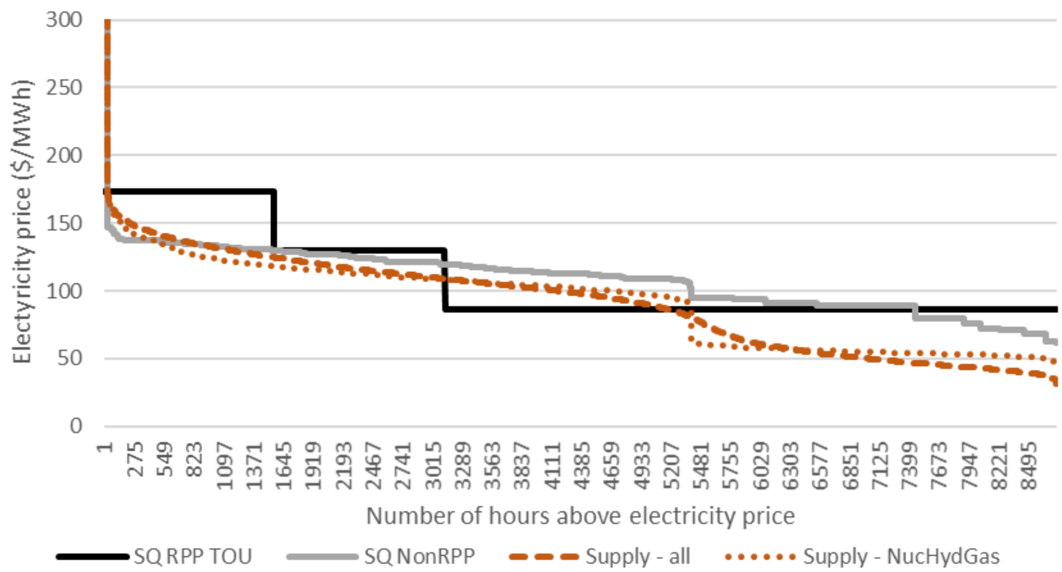
The supply-shaped pricing prototype is designed so that the GA costs of different generators are recovered in the hours in which those generators produce electricity. In principle, this could be done for each generator individually or for groups of generators that share similar characteristics. Deciding which generator classes to include in shaping the price in this way and how each generator class is defined is the primary adjustable parameter in this prototype. All other GA costs that are not “shaped” contribute to the electricity price equally in all hours. Specifically, for each generator category in any year, the total annual GA costs paid to that category are divided by the total annual MWh generated by that category to get a $/MWh contribution for that category, which is then charged to consumers for the MWh generated in each hour by that category in that year.

For this analysis, two supply-shaped pricing variants are introduced, one in which five categories of generators are shaped, the other in which three categories of generators are shaped.

Table 5: Variants of the supply-shaped prototype.

Reference	Pricing prototype	Description	Adjustable Parameters
Supply - all	Supply-shaped	HOEP + GA price correlated to hourly generation across all technology categories	The GA price is shaped by 5 categories of generators: nuclear, hydro, gas, solar and wind
Supply - NucHydGas	Supply-shaped	HOEP + GA price correlated to hourly nuclear, hydro and gas generation	The GA price is shaped by 3 categories of generators: nuclear, hydro and gas

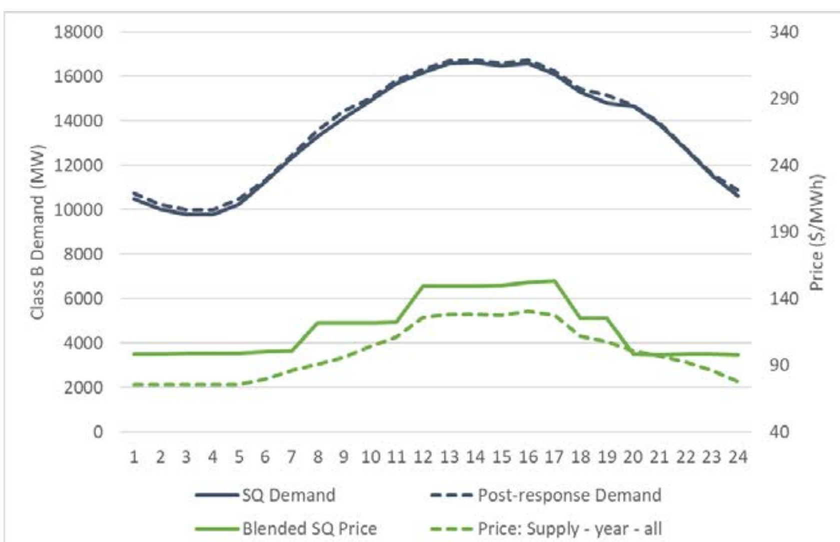
Figure 27: Price duration curves for variants of the supply-shaped prototype for calendar year 2018.



The price duration curve shows that, except for a few hours of the year when HOEP is very high (the far left side of the plot), the supply-shaped prices vary quite moderately compared to other prototypes studied.

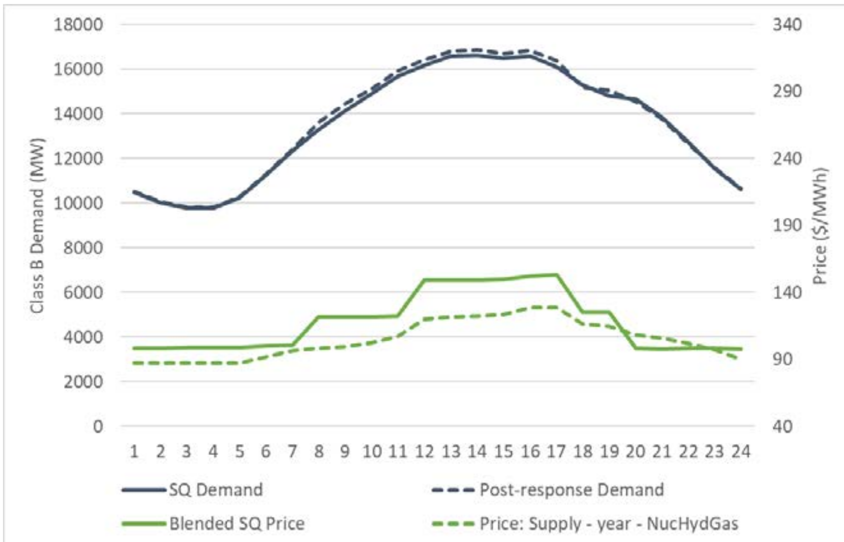
3.5.1 Demand Response

Figure 28: Example of prices and class B demand response in the Supply - All variant on a simulated hot summer day.



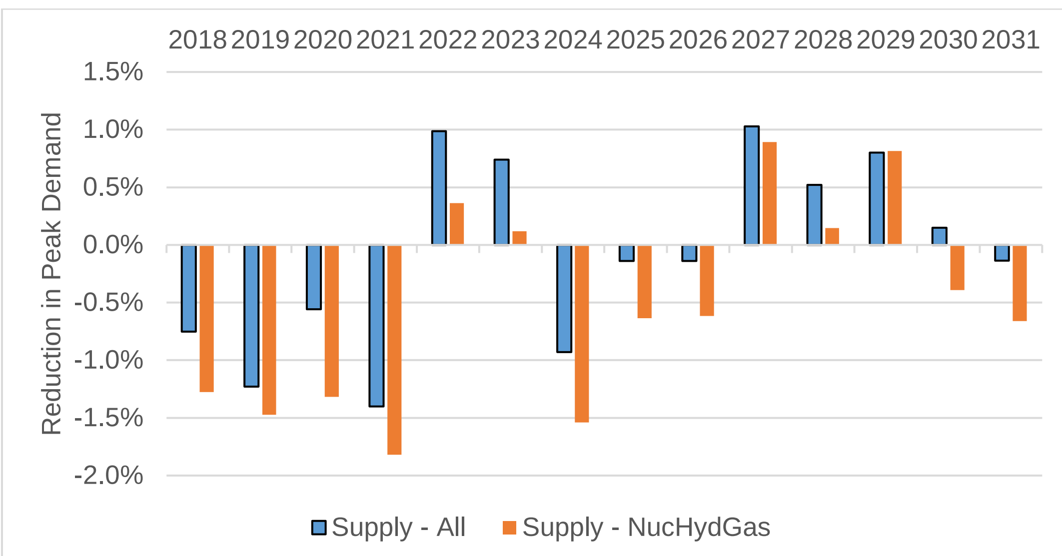
The horizontal axis indicates the hour in the day.

Figure 29: Example of prices and class B demand response in the Supply - NucHydGas variant on a simulated hot summer day.



The horizontal axis indicates the hour in the day.

Figure 30: Annual reduction in peak demand for the supply-shaped pricing variants.



3.5.2 Avoided Costs, Consumer Benefit and Total Welfare

Figure 31: Avoided cost, consumer benefit and total welfare in the Supply – All pricing variant.

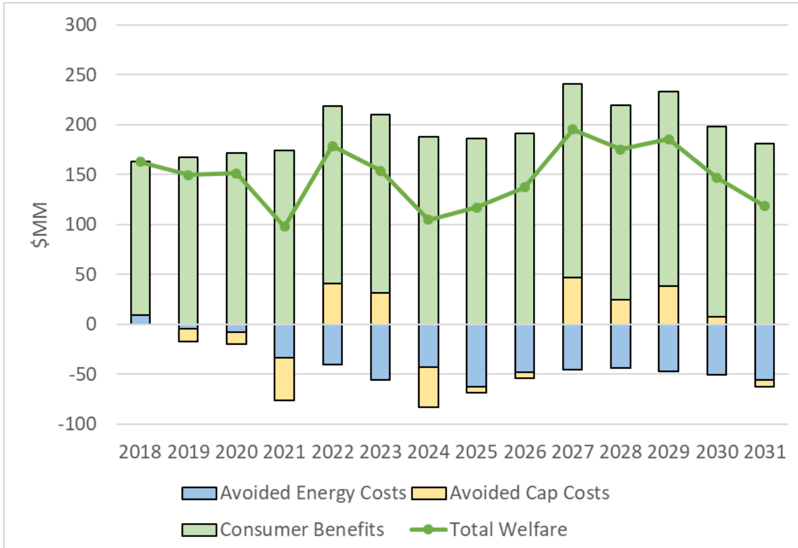
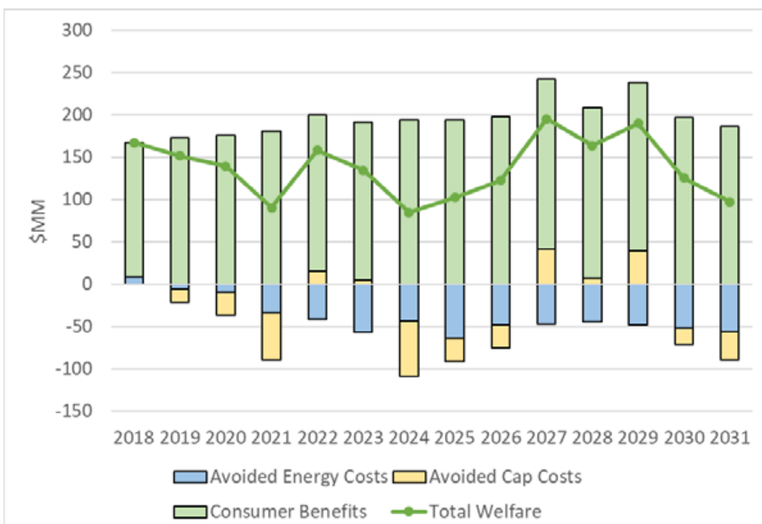


Figure 32: Avoided cost, consumer benefit and total welfare in the Supply – NucHydGas pricing variant.

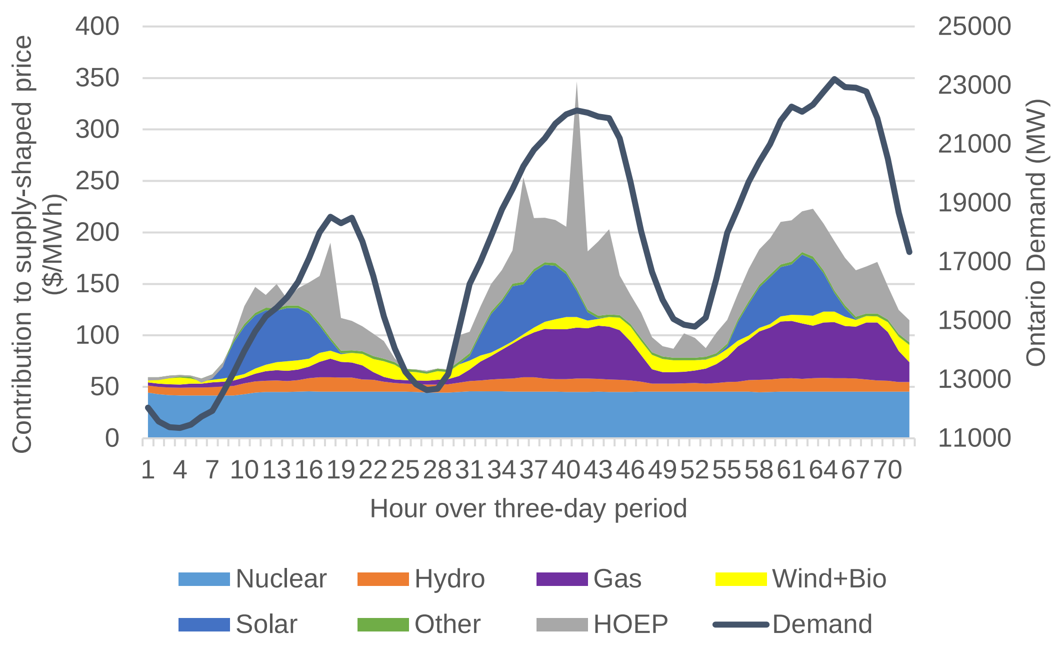


While avoided costs in these examples are quite small over the forecast period, the benefit to consumers is positive in all years leading to an overall positive total welfare. Further, there is little impact to economic efficiency as a result of including or excluding wind and solar generation from the shaping of the GA costs in this pricing prototype.

Upon first examination it might be expected that the results of the economic efficiency of the supply-shaped variants would mirror those for the demand-shaped prototype since the amount of generation increases with demand. The primary difference arises from the fact that, while the demand-shaped price distributes all GA costs in a cost recovery period based on the demand in any given hour, the supply-shaped prototype distributes the costs for each technology individually based on the generation and GA cost contribution of that technology. While total generation in any given hour is strongly correlated with Ontario demand, the cost impact will not necessarily follow. The wide range of GA costs per unit of generation for different technologies as well as the intermittency of renewable generation (in the Supply – All variant) are primary drivers of this outcome.

For example, in Figure 33, the contribution to price is plotted for each hour over a 3-day high-demand period in the Supply – All variant alongside the Ontario demand during this period. In this illustration, although solar generation makes up a relatively small portion of the overall supply mix, solar costs have a strong influence on the supply-shaped price due to the fact that the proportion of solar costs in the total GA is higher than the proportion of solar generation in the supply mix and the fact that these costs are confined to the hours in which solar generators actually generate. As a result of these dynamics, the supply-shaped price is correlated to demand but not as strongly or directly as in the demand-shaped pricing prototype. The result is that lower relative prices are offered during high demand periods and higher relative prices are offered during low demand periods (compare price in high-demand hours 20 and 68 in Figure 33 with prices in lower-demand hours 13 and 62 respectively). This incentive for consumers to consume more during some periods of high demand leads to a positive consumer benefit.

Figure 33: Hourly price of the Supply - All variant of the supply-shaped pricing prototype over a three-day high-demand period.



3.6 High-N Price

The high N pricing prototype is designed to be a generalization of the price experienced by participants in the ICI but applied to all class B consumers. Whereas GA costs are recovered from ICI consumers based on their electricity consumption during the five highest electricity demand hours within a 12-month base period, the high N pricing prototype recovers GA costs from class B consumers based on their consumption during the N highest demand hours within each cost recovery period. Further, a parameter is introduced to allow for only a fraction of GA costs to be recovered in the highest N demand hours. This fraction is labelled by σ and variants with $\sigma = 0.5$ are examined in this paper.

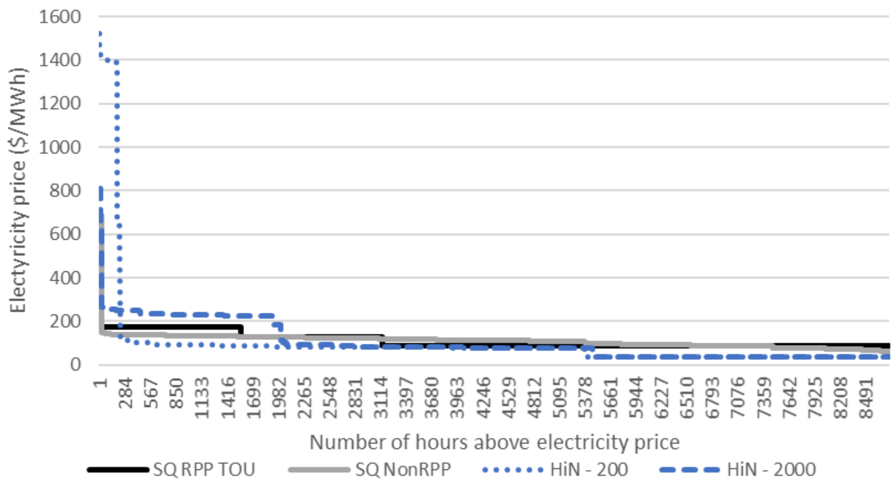
For ICI consumers, their consumption during the 5 highest electricity demand hours in the base period determines how much they are charged for GA in the *subsequent* 12-month period following the base period. One could imagine defining a similar type of cost recovery mechanism for the high N pricing prototype as well. However, regardless of when the costs are actually recovered, the consequence of the ICI pricing program is to create an *effective* price that is much higher in the 5 highest demand hours, regardless of when the costs are actually recovered. Therefore, in order to simplify the analysis of this prototype, the high N pricing prototype is defined using this effective price, assuming that it is charged in real time so as to recover the GA costs within the cost recovery period in which the prices are defined.

In cases where each of the highest N demand hours is known by consumers in advance, the higher effective price in the N hours is the value of electricity in those hours. In cases where not all of the highest N hours are known with certainty by consumers in advance, it is likely that consumers will try to lower their consumption in hours beyond the highest N hours to ensure that none of the highest hours are missed, thus creating a perceived effective price in more than N hours from the perspective of the consumer. In this way, the $N = 200$ variant, captures the effects of both a high N scenario with 100 high-GA-priced hours that are not known in advance in which consumers lower their demand during an additional 100 hours (200 hours total), as well as a 200-hour high N design under which all 200 high-GA-priced hours are known in advance. In both cases, consumers are assumed to respond to peak pricing in 200 hours. These design differences are relevant to implementation but do not influence the results of the economic efficiency analysis.

Table 6: Variants of the High-N prototype.

Reference	Pricing prototype	Description	Adjustable Parameters
HiN - 200	High N	HOEP + flat monthly GA price + increased GA price in the highest 200 demand hours	$\sigma = 0.5, N = 200$
HiN - 2,000	High N	HOEP + flat monthly GA price + increased GA price in the highest 2,000 demand hours	$\sigma = 0.5, N = 2{,}000$

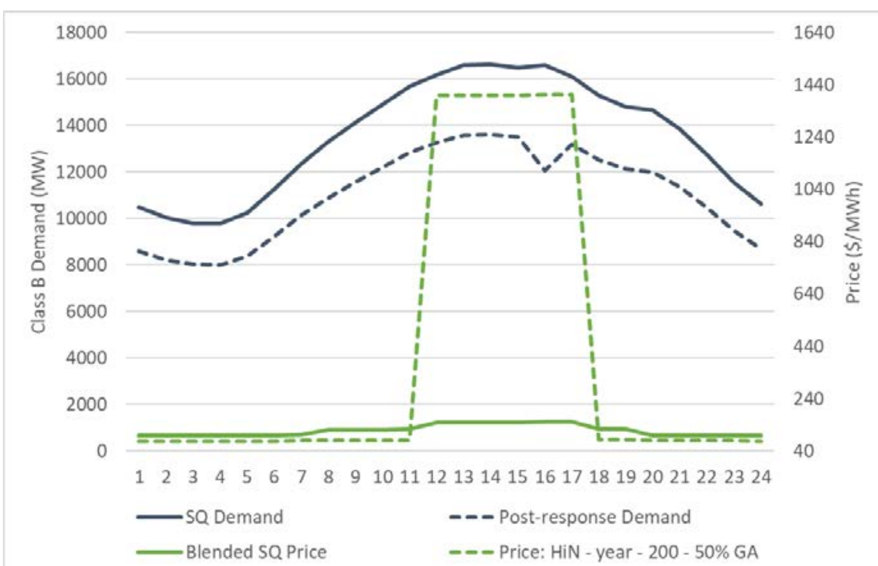
Figure 34: Price duration curves for variants of the High N prototype for calendar year 2018.



Note the much larger scale on the vertical axis compared to other price duration graphs in this section. The price duration curves show that, in the HiN – 200 variant, the electricity price reaches values around $1,400/MWh in the highest 200 demand hours whereas the HiN – 2,000 variant exhibits prices around $220/MWh in the highest 2,000 demand hours.

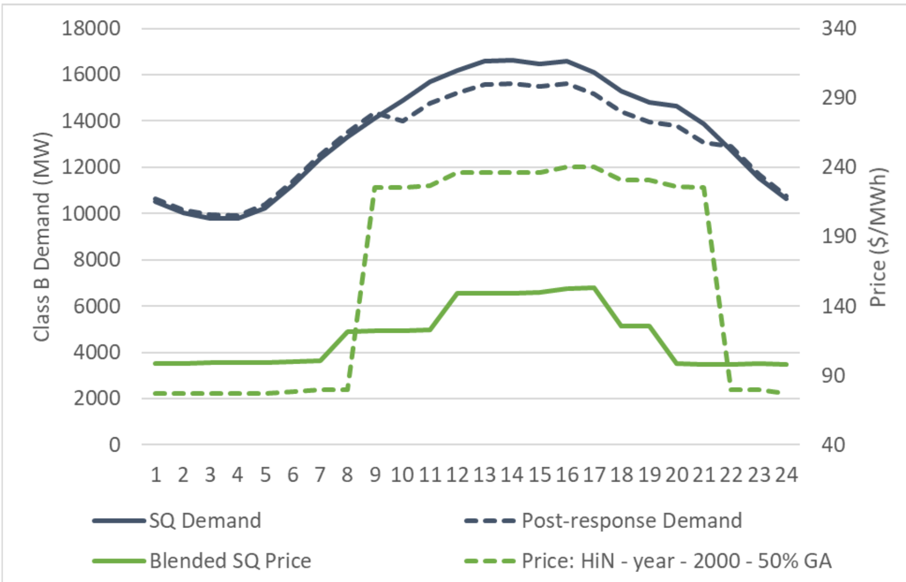
3.6.1 Demand Response

Figure 35: Example of prices and class B demand response in the HiN - 200 variant on a simulated hot summer day.



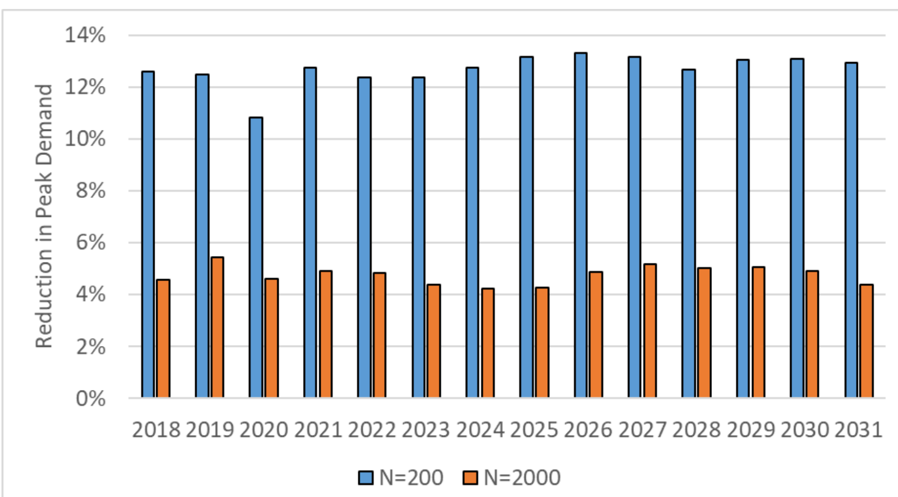
Note that the price scale on the rightmost vertical axis is much larger than in similar pricing graphs presented in other sections. The reason that the post-response demand is lower in all hours is because own-price elasticity is based on the comparison of average daily prices and is applied to all hours in a day equally before the elasticity of substitution is applied. Because the new average price over the course of the day is so much higher than the SQ average price, the overall response in all hours is lower. Note that the response during the high-200 hours is still lower, proportionally compared to hours in which the price is lower. The horizontal axis indicates the hour in the day.

Figure 36: Example of prices and class B demand response in the HiN - 2,000 variant on a simulated hot summer day.



The horizontal axis indicates the hour in the day.

Figure 37: Annual reduction in peak demand for the High *N* pricing variants.



3.6.2 Avoided Costs, Consumer Benefit and Total Welfare

Figure 38: Avoided cost, consumer benefit and total welfare in the HiN – 200 pricing variant.

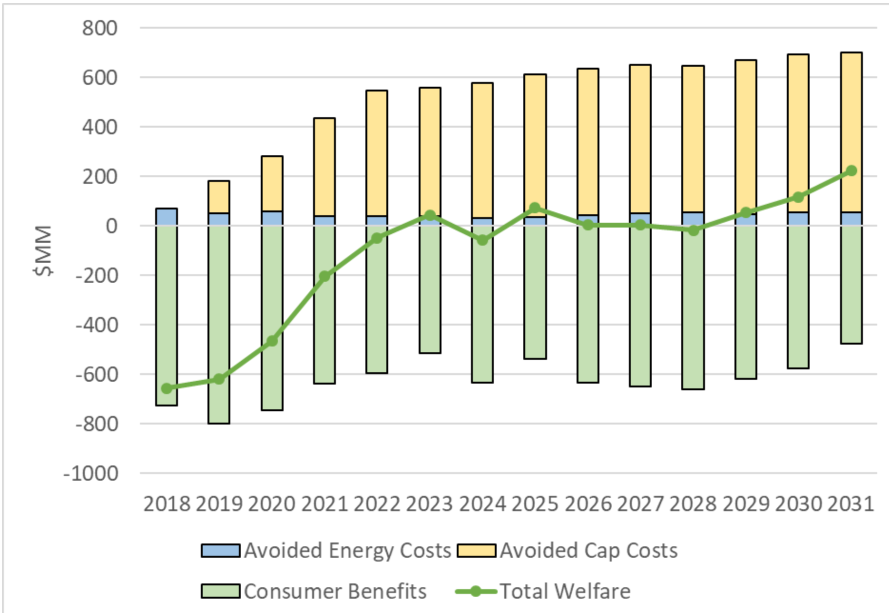
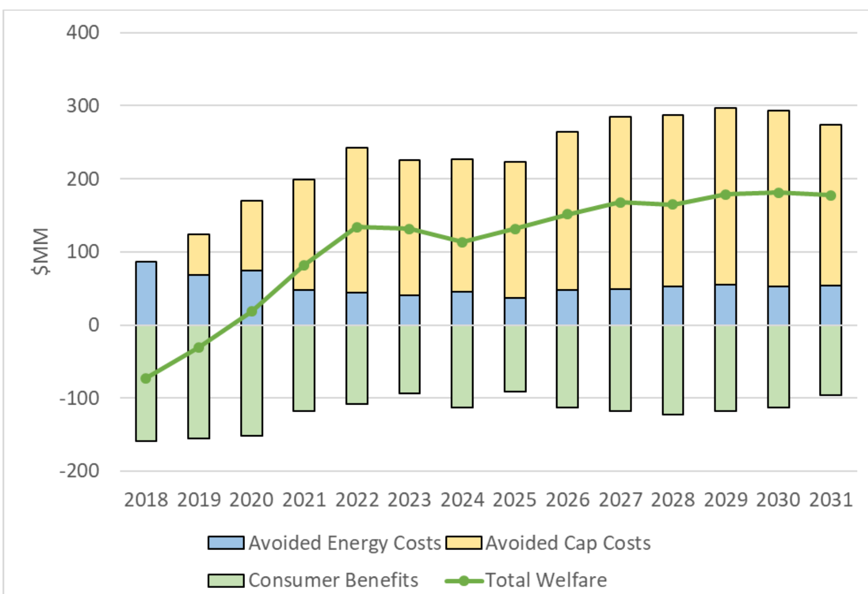


Figure 39: Avoided cost, consumer benefit and total welfare in the HiN – 2,000 pricing variant.

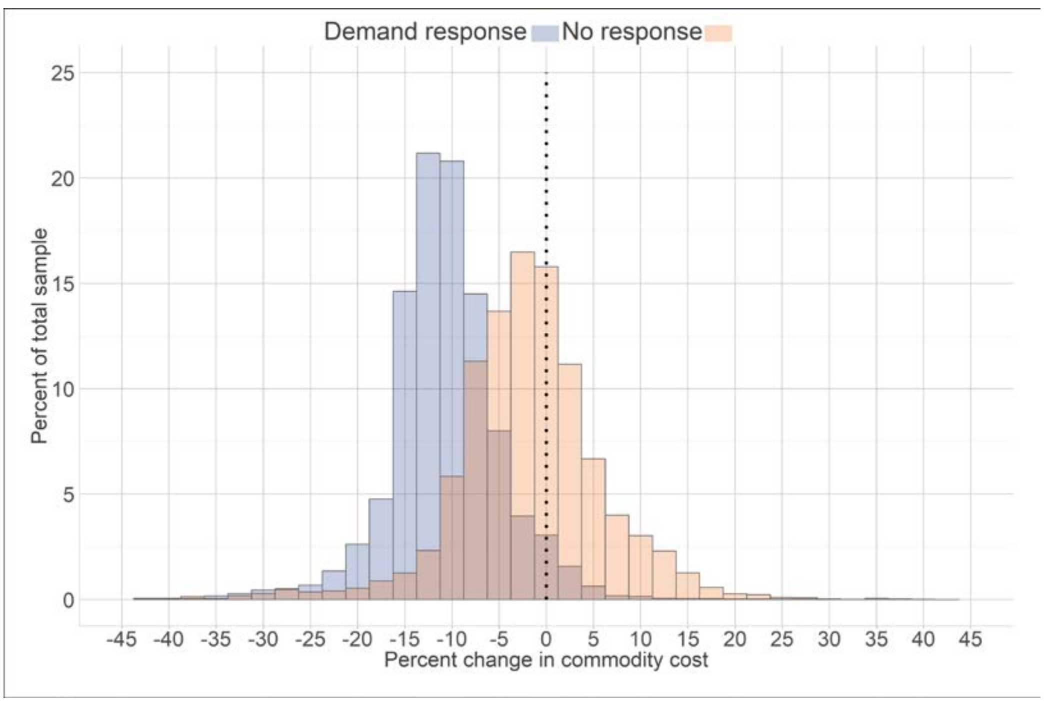


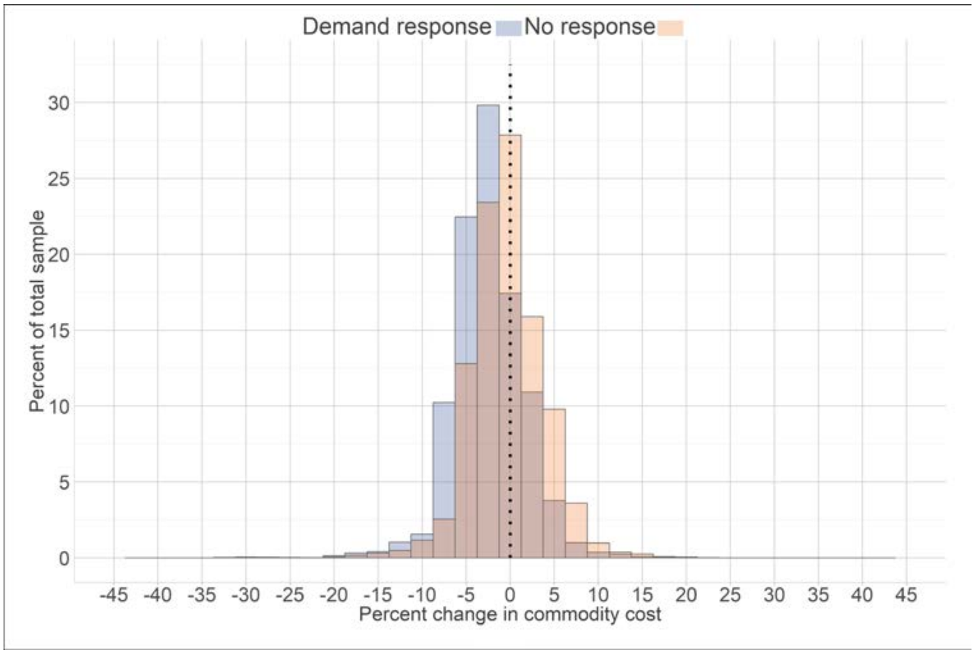
The motivation for the High *N* pricing prototype is to focus high prices only in the hours with the highest demand in a cost recovery period and offer lower prices in all other hours relative to the status quo. The high peak prices reduce peak demand and, thus, reduce costs (create positive avoided costs) in all years over the forecast period. These positive avoided costs are counterbalanced by negative consumer benefits: the high cost of reducing demand during significantly higher priced hours is greater than the added value of consuming more during all other hours that experience prices lower than the status quo. This balance between avoided costs and benefits is qualitatively similar to that exhibited in the demand-shaped pricing variants. However, in this case, the negative consumer benefits are significantly greater, leading to decreased welfare in the $N = 200$ case across all years and only a very modest increase in welfare in the later forecast years in the $N = 2{,}000$ case.

While increased prices during peak demand do lead to avoided system costs, the way in which those prices are defined and the way in which consumers react to those prices will lead to different impacts on consumer benefit that will determine whether or not the pricing system leads to an increase in total welfare for consumers.

3.6.3 Distribution of Consumer Cost Impacts

Figure 40: Consumer impact distribution for the HiN – 200 – 50% GA (top) and HiN – 2000 – 50% GA (bottom) price variants.





The width of each bin represents a 2.5% change in commodity costs. The demand response scenario assumes consumers adapt their hourly demand to the new prices. The no response scenario assumes no change in consumer demand in response to new prices.

Prototype	**Response Type**	**Percentage of Customers that Experience a Cost Decrease**	**Percentage of Customers that Experience a Cost Increase**
HiN – 200 – 50% GA	No response	62	38
	Demand response	95	5
HiN – 2000 – 50% GA	No response	56	44
	Demand response	75	25

3.7 Comparison of All Pricing prototypes

Having presented the quantitative results of the economic efficiency analysis for each pricing example individually, this section concludes by comparing some of the key results across pricing options. The results for each prototype show the impact that is expected relative to the situation where consumers are charged status quo prices.

3.7.1 Demand Response

The two figures below show the estimated change in peak demand for each pricing example, first in forecast year 2018 then in forecast year 2030.

Figure 41: Fractional change in peak demand in forecast year 2018

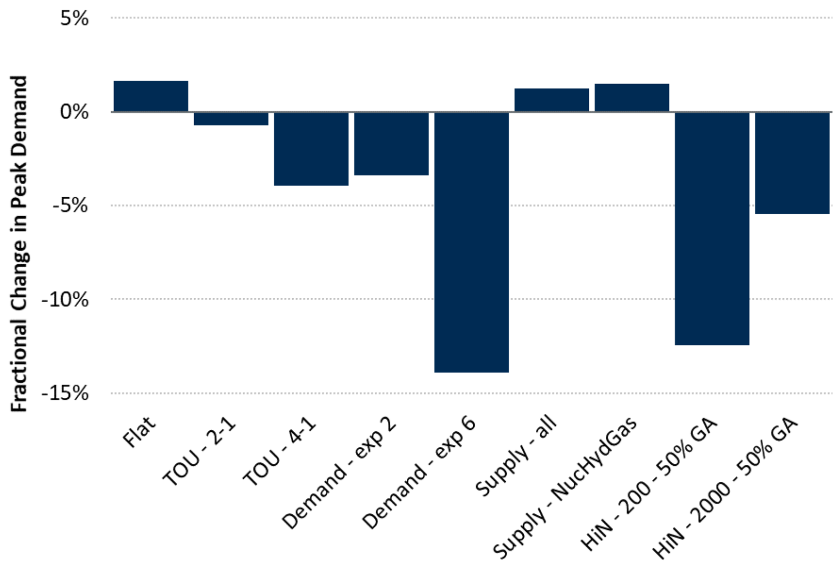
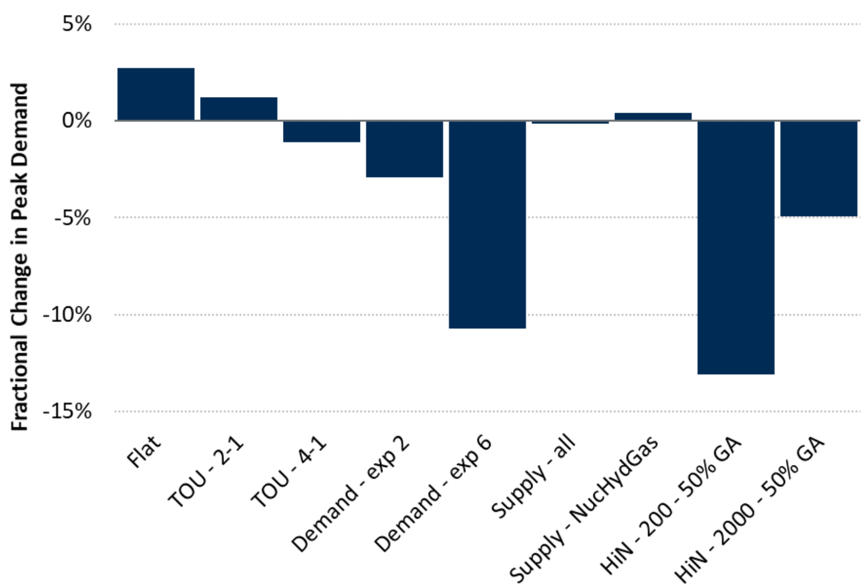


Figure 42: Fractional change in peak demand in forecast year 2030



Here it is seen that the change in peak demand is relatively similar in 2018 and in 2030. This is not surprising as the definition of each prototype remains the same over the forecast period so its value relative to the status quo price – and hence the estimated demand response of each – will also be similar across the forecast period.

3.7.2 Avoided Cost, Consumer Benefit and Total Welfare

The two figures below show the estimated avoided costs, consumer benefit and total welfare for each pricing example, first in forecast year 2018 then in forecast year 2030.

Figure 43: Avoided cost, consumer benefit and total welfare in forecast year 2018

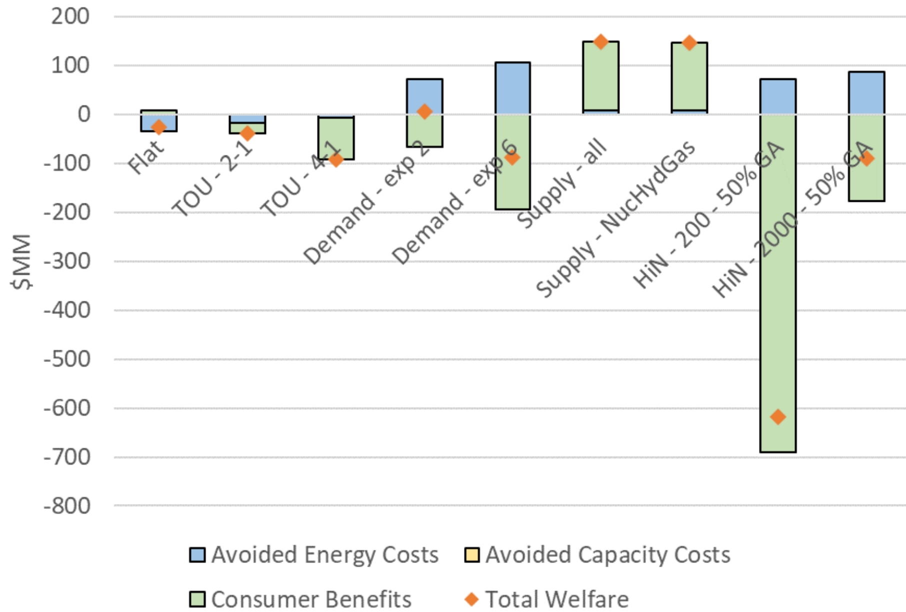
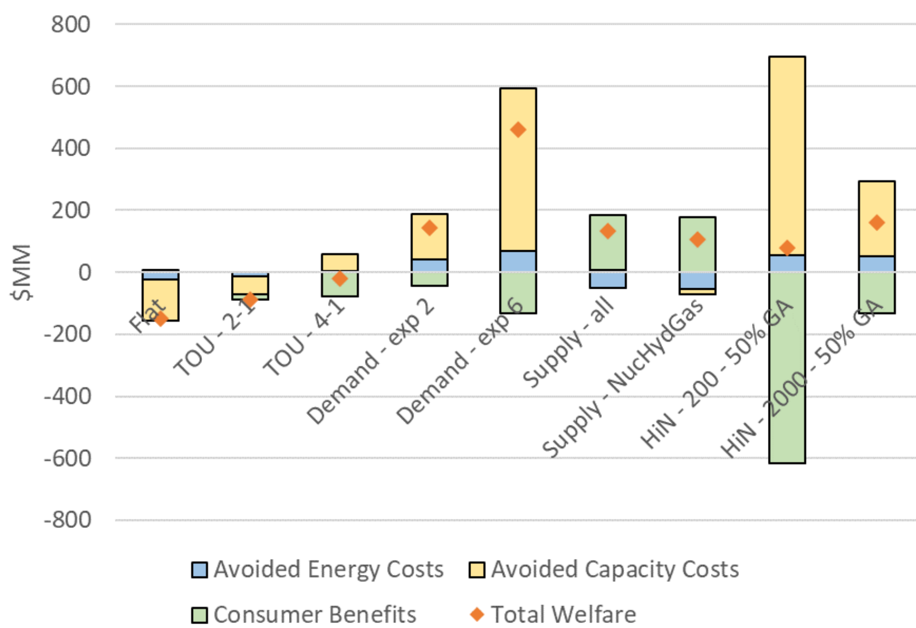


Figure 44: Avoided cost, consumer benefit and total welfare in forecast year 2030



These results show that, early in the forecast period, there is minimal avoided capacity cost. The Ontario electricity system is expected to have sufficient capacity under the status quo scenario until the end of 2022 [16]. As a result, there are no capacity cost savings in the early years due to a decrease in peak demand. Even in those pricing examples that exhibit an increase in peak demand, there is no increase in capacity costs as there is currently sufficient capacity to accommodate such peak demand increases.

This section concludes with a summary of the economic efficiency analysis showing the average change in annual peak demand along with the NPV of annual avoided costs, consumer benefits and total welfare over the forecast period. A nominal discount rate of 6% is assumed when calculating the NPV.

Table 7: Summary of economic efficiency results over the forecast period 2018-2031.

	Flat	TOU - 2-1	TOU - 4-1	Demand - exp2	Demand - exp6	Supply - All	Supply - NucHydGas	HiN - 200 - 50% GA	HiN - 2000 - 50% GA
Average percentage change in annual peak demand	2.3%	0.6%	-2.0%	-2.9%	-11.5%	0.1%	0.5%	-12.7%	-4.8%
NPV Avoided Cost ($M)	-$943	-$361	$626	$1,338	$4,180	-$294	-$446	$4,429	$1,996
NPV Consumer Benefit ($M)	$48	-$54	-$1,135	-$230	-$1,478	$1,666	$1,724	-$5,972	-$1,138
NPV Total Welfare ($M)	-$896	-$415	-$508	$1,108	$2,703	$1,372	$1,278	-$1,543	$858

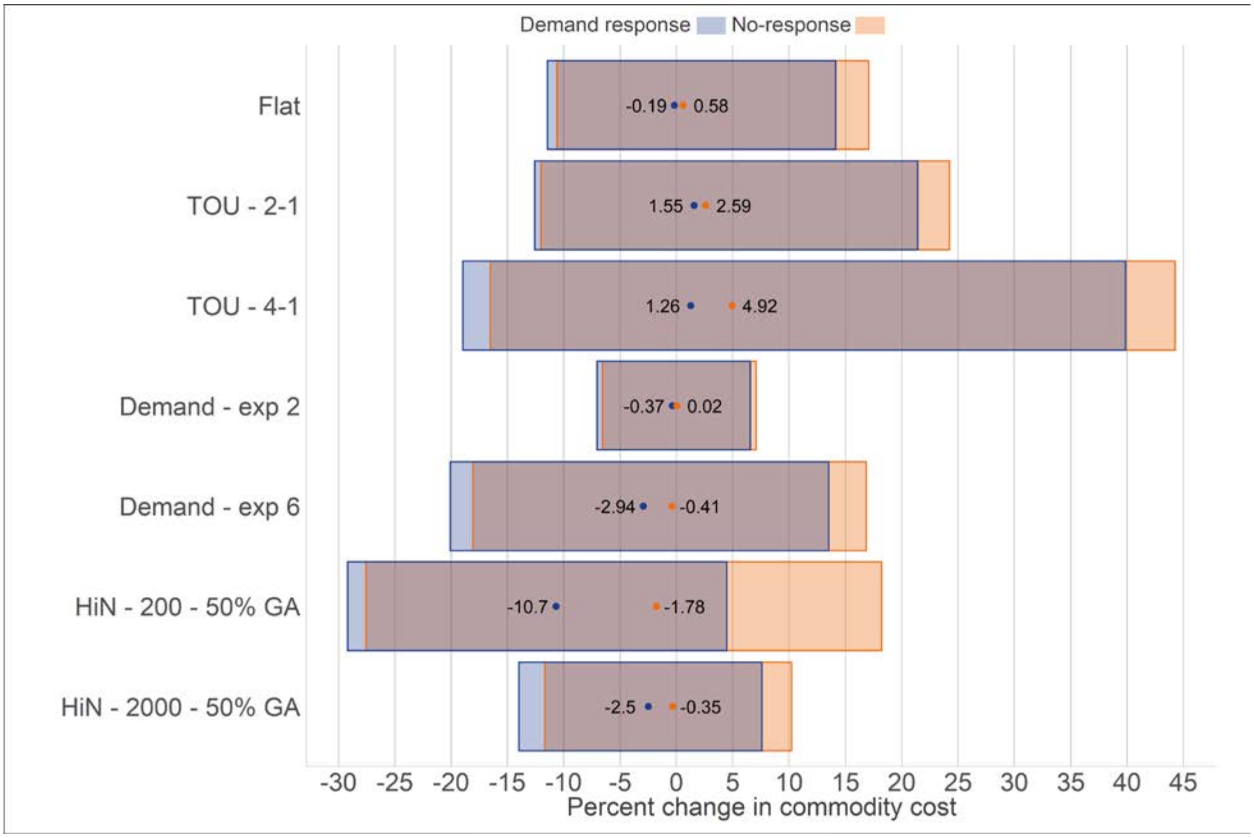
The NPV values were calculated over the entire forecast period 2018-2031 assuming a nominal discount rate of 6%. Discrepancies between the sum of Avoided Cost plus Consumer Benefit and Net Benefit are due to rounding to the nearest integer dollar value.

Further discussion of these results is provided in section 4.

3.7.3 Distribution of Consumer Cost Impacts

The graph below presents the results of the statistical analysis of consumer cost impacts under the two scenarios as described in section 2.4. Although it is unknown the degree to which the data sample of 6,940 consumer profiles is representative of a larger population, these results nevertheless provide an indication of the distribution of cost impacts for each pricing option under consideration under both the No Response scenario and the Demand Response scenario.

Figure 45: The change in annual commodity cost relative to the status quo price under each pricing option at the individual consumer level in the No Response and Demand Response scenarios.



In addition to showing the range of cost impacts for each pricing variant, this graph also provides an indication of the cost savings that can be realized when consumers respond to a change in price in each of the options studied. Of particular note is the significant difference between the No Response and the Demand Response scenarios in the High-N N=200 variant, which is significantly larger than the difference observed in the other variants. In the N=200 case, the price is more than $1,200/MWh in the highest 200 hours, significantly more than the status quo price in those hours. Such a drastic difference in price over so few hours induces the most extreme demand response in those hours, allowing consumers to save significantly more on their bills compared to other variants given the assumptions used in the analysis. These cost savings are of course offset by lost consumer satisfaction – that is, lost consumer benefit – because of their reduced electricity use in the High N hours.

4 Discussion

In this paper, several pricing variants from a set of five defined prototypes have been examined and each evaluated based on the principles of revenue adequacy (achieved through the design of each prototype), economic efficiency and consumer bill impact. Further research is currently ongoing that will examine in more detail the range of consumer bill impacts as well as additional considerations as the policy development process continues towards a new pricing structure for class B consumers.

Below are a number of "lessons learned" that summarize some of the most useful results from this analysis. Section 4.2 discusses some issues of practical implementation and presents a basic model for how such pricing prototypes could form the foundation for electricity prices for class B consumers. This section also briefly addresses several additional pricing design considerations that will be further explored in the future. Finally, this paper concludes with a discussion of several future changes to the electricity market and pricing that are under development and how such changes can be incorporated into the pricing structures discussed in this paper.

4.1 Lessons Learned

In OEB staff's view, the most salient lessons to be learned from this analysis are as follows:

1. **Need to balance system savings with consumer benefit**
   While prices that allocate GA costs to produce demand-responsive behaviour can increase overall net economic benefit by deferring infrastructure needs, extreme pricing can reduce overall benefit by inducing consumers to avoid consuming even when it would otherwise be beneficial for them to do so. The need for this balance is best exemplified in the analysis of the High-N pricing prototype, where the negative impact to consumer benefit due to demand reductions during the highest N electricity demand hours was estimated to be greater than the resulting system cost savings.

2. **Correlating GA prices with demand yields positive economic efficiency results**
   Allocation of GA costs more correlated with Ontario demand can yield higher economic benefits relative to both the current Class B price design as well as to other scenarios studied. It is effective at inducing demand response without inducing overly costly curtailment in hours where consumer response is not needed.

3. **Basing GA prices on the hourly quantity and GA cost of each resource is not efficient**
   Allocation of GA costs in proportion to the GA costs of the type of resources (supply) running in each hour is less economically efficient than other prototypes studied. It is less effective at spurring demand responsive behaviour because such prices do not always align high prices with periods of high demand. Nevertheless, such a shaping of price does appear to offer positive consumer benefits relative to status quo pricing.

4. **Reductions in consumer benefit can swamp system savings for Class A-like GA allocation**
Allocation of half of GA costs into the highest electricity demand hours, a design similar to pricing under the Industrial Conservation Initiative (ICI) applied to Class A consumers, is generally as effective at deferring new system needs as demand-based pricing approaches but yields significant reductions to consumer benefit such that the likelihood of overall negative net benefits rises as the number of targeted hours diminishes. As a result, the High-N prototype risks being significantly less economically efficient than the other options studied.[17]

5. **Reallocation of GA designs can reduce costs for consumers able to respond to better price signals, but greater information regarding consumer acceptance is required**
An analysis of the consumption patterns of about 7,000 larger general service customers confirms that the cost consequences of alternatives to the status quo Class B GA price can generate moderate savings on average and individual savings for those consumers who can respond to price signals. However, more work remains to be done to understand consumers' views about price changes. This includes how consumers would trade off cost causality in prices in order to gain more predictability in the prices they pay. It is also important to know more about their preferences – their attitudes not merely to price increases in periods of higher demand, but also their disposition toward the prospect of lower prices in lower-demand periods – and their views of the opportunities, costs and interest in managing greater price exposure through demand response and other measures. The RPP pilots are underway and additional direct engagement with consumers is planned. Both activities are expected to shed light on these issues.

4.2 Considerations for Implementation of a New Class B Price

All of the quantitative economic research presented in this paper has been conducted in a model universe of perfect information and perfect foresight assuming that consumers behave in accordance to empirical studies of the elasticity of electricity demand. Such simplifications are necessary in order to arrive at concrete quantitative results but the possibility of applying such prices to real consumers warrants consideration.

In each of the pricing prototypes considered, one needs to know HOEP, GA cost, demand and, in the case of the supply-shaped price, generation information over the entire cost recovery period in order to formulate the price during that period so as to precisely recover all required revenue. How prices could be formulated for actual consumers in the absence of such knowledge requires additional thought.

In OEB staff's view, the approach used to determine RPP prices is instructive. For these prices, the IESO provides the OEB with actual cost and demand data over the prior 12-month period. These data inform a forecast of costs and volumes expected over the upcoming 12 months; differences between forecast and actual cost and volumes are tracked in a variance account.

[17] A recent Market Surveillance Panel report [33] evaluates the impact and potential alternative approaches to the ICI for Class A consumers.

The OEB establishes RPP prices so as to recover the required revenue as well as to recover or return any past differences between revenues and costs. The factor required to clear the variance balance is set to dispose of any balance over a 12-month period on a forecast basis.

A similar process can be used to set prices for each of the prototypes introduced in this paper. For example, prices in the TOU prototype can be calculated in precisely the same way as RPP TOU prices are currently set, but including all class B consumers instead of just those who currently participate in the RPP. In the case of the demand-shaped price, for example, which includes an overall numerical factor d^* that is calculated so as to fully recover all required revenues (see Appendix A for details), the value of d^* can be calculated in the same way as in the current paper based on hourly forecast data over the cost recovery period and published prior to the period. With the value of d^* over the cost recovery period established, the price in any given hour can then be determined using the real-time values of HOEP, GA cost (using the IESO's best estimate at the time of calculation) and Ontario demand. A similar process can be used for all other prototypes and any discrepancy between revenue collected and total supply cost can be included in a variance account and rolled into the next cost recovery period.

Many of the prototypes proposed incorporate real-time information. While this allows for the formulation of a price that is responsive to real-world system conditions, it makes it more difficult for consumers to know what the price for electricity will be in advance and thus adapt their behaviour to respond to such price signals. The quantitative analysis in this paper has made the simplifying assumption that consumers have instantaneous knowledge of the price in each hour and are able to adapt instantaneously. In reality, prices could be published or communicated to consumers in advance based on forecast data, either in a binding way regardless of what actual system conditions are, or as an estimate subject to later correction through the disposition of variances, much like the practice that applies to consumers charged on the basis of estimates of GA.

Advance notification of prices may be aided by the introduction of a binding day-ahead energy market, a possibility explored in section 4.3.2. Determining how prices can most effectively be communicated to consumers will be a key aspect in the detailed design of any new class B pricing framework.

4.2.1 Application of a New GA Price

The assumption throughout this paper is that the prices examined would be charged directly to all class B consumers. While it may be appropriate to charge such prices directly to some consumers, OEB staff expects that there will continue to be a policy basis for offering simpler or less dynamic price plans that have been defined in advance on a forecast basis such as is seen in today's RPP.

The use of a different GA price design is no barrier to continuing this pricing model. For forward price plans, the desired pricing prototype deemed most beneficial can be formulated using forecast data as described above and serve as a "foundational" price from which all higher order prices can be determined by taking appropriate weighted averages of that foundational price. In this way, all class B consumers will be subject to the same beneficial underlying pricing dynamics on average, creating a more fair allocation of cost and improving the misalignment of GA issues discussed in section 1.

For example, suppose it is decided to implement the demand-shaped price as the foundational price for all class B non-RPP consumers while retaining a TOU approach to prices for RPP. In advance of the first cost recovery period, the hourly demand-shaped pricing series can be calculated over the entire period using forecast data. Demand-weighted averages of this price series can then be calculated over each price period, however defined, to provide a set price within each period that will then be charged to RPP consumers. Any discrepancy between revenues collected and total supply costs over the cost recovery period can be recovered or returned through a variance account in the subsequent cost recovery period as is currently done in the RPP.

While many decisions and details would remain to be worked out if a new paradigm for class B pricing were to be adopted, OEB staff suggests that the basic prototypes assessed in this paper and the lessons learned from this analysis could be viably implemented in ways that address objectives and criteria beyond the scope of its analysis. Some of these considerations are discussed in the following section.

4.2.2 Additional Evaluation Criteria

Discussions of retail electricity pricing usually consider more than the principles of revenue adequacy, economic efficiency and consumer bill impact examined in this paper. It is typical that other questions such as fairness, predictability and consumer acceptance also apply to considerations of rate design.

A core component of evaluating fairness has typically consisted of determining whether or not a given rate structure involves subsidies between groups of customers. Any customer whose costs fall outside of a “subsidy-free” range may have an incentive sufficient to defect from the grid. If consumers seek supply elsewhere, they would duplicate at least some of the common costs of the grid. These outcomes are likely to be economically inefficient as well as unfair.

While the prototypes developed could be tested for the presence of defection risk, OEB staff is of the view that it would be premature to assess non-efficiency features of pricing alternatives at the prototype stage. The assumptions and constraints necessary to carry out comparisons of prototypes – in particular, those regarding perfect information and perfectly rational behaviour – prevent a thorough assessment of the fitness of a pricing plan for implementation across a range of customers. This is because such an evaluation necessarily involves consideration beyond the questions of subsidy, and into broader matters such as risk tolerance, availability of pricing information and fundamental differences in customer preferences, not all of which are well understood, or can be accurately applied to abstract price structures.

More information regarding customer preferences and price-responsive behaviour is expected to become available through the results of RPP pilots, many of which involve more dynamic pricing and critical peak pricing events. Further stakeholder engagement will also shed light on these preferences. OEB staff proposes to conduct broader evaluation of pricing proposals once they have been more fully developed and once more empirical information on customer preferences is in hand.

4.3 Adapting to Future Developments in Ontario's Electricity Market

The analysis and results presented in this paper were formulated based on the way in which the Ontario electricity market currently functions. However, over the past several years, the IESO has been designing several proposed changes to the way in which the Ontario electricity market operates that could impact Ontario electricity pricing. The process for developing these changes is termed, collectively, as "market renewal" [5]. The market renewal process is still ongoing but several significant proposals have emerged as potential new features of the market. This section discusses three such features that could impact the development of new class B pricing and how the pricing prototypes presented in this paper could be adapted to incorporate these forthcoming changes if implemented. The subject of policy-driven price designs is also addressed.

4.3.1 Single Schedule Locational Pricing

All consumer electricity prices currently, and all of the pricing prototypes defined in this paper, depend on the single HOEP that currently applies universally across the province. Under a single schedule system, the HOEP would be replaced by a collection of prices at different locations. The degree to which non-market participants would be exposed to these locational prices remains to be decided. While the specific details of such a single schedule system are still being worked out, two general options present themselves regarding class B electricity pricing:

1. When calculating the price that is to apply to a specific consumer, replace HOEP with the locational price that applies to that consumer's location. In the formulation of the pricing prototypes, this amounts to replacing HOEP h_i in all formulae in Appendix A with the locational price that applies to that consumer in hour i. This can apply to both the prototypes that pass HOEP directly to the consumers as well as those that construct a set forward price. In this way, the price signal developed by the single schedule market can be passed on to consumers directly while GA costs will still be distributed to all Ontarians universally depending on the specific formulation chosen.

2. Develop a new universal Ontario electricity market price as the load-weighted average of all locational prices in each hour. This new universal price can then be used in precisely the same way as HOEP is used in the development of each of the pricing prototypes.

4.3.2 Binding Day-Ahead Electricity Market

The IESO is in the process of designing an electricity market that would settle offers and bids for electricity a day in advance of when those generators would be dispatched. The prices and dispatch orders developed from this market would be binding and the real-time market would be used as a "balancing" market based on real-time conditions, likely settling a far lower volume of transactions compared to the day-ahead market. Such a change is likely not to have a significant impact on the design of class B pricing.

4.3.3 Incremental Capacity Auction

An auction process is being designed by the IESO to procure resources for electricity capacity. The auction would be used to procure all additional resources incremental to those already under prices set by contract or regulation.

The IESO's current auction, which secures demand response resources, recovers its costs through the wholesale market service charge. Should costs from a future auction be recovered through GA, no material change to prototype designs would be required in order to recover those costs from consumers in the same manner as other GA costs. Resources that clear the capacity auction can simply be incorporated into the definition of the prototype in precisely the same manner as other GA costs are treated. This amounts to replacing, in Appendix A, all instances of the GA cost term C_α with $C_\alpha + C'_\alpha$ where C'_α is the total of revenues paid to resources through the capacity auction in cost recovery period r_α. That is, all capacity costs should be treated precisely in the same way as GA costs in the development of a Class B price for electricity supply.

4.3.4 Policy Compatibility

For some consumers in Ontario, electricity prices are not designed to recover the full cost of electricity supply. Rather, a fraction of electricity costs is paid from sources other than electricity consumers, such as from provincial revenues, debt financing or other means[18]. While complete revenue adequacy was a design constraint of the analysis in this paper, the ability to adjust revenues required to be recovered from customers through the GA means it remains compatible with a range of policy intents regarding the recovery of supply costs.

[18] See, for example, the impact on electricity pricing from the Ontario Fair Hydro Plan Act passed by the Ontario government in 2017 [29].

A. Definition of Pricing Prototypes

This appendix provides the technical definitions of each pricing prototype studied in this paper along with details on each example studied in this analysis. While each prototype is designed to recover all electricity supply costs attributed to Class B consumers, the period over which those costs are recovered can be defined, typically from one month up to one year. Greek indices α, β, γ ... are used to label each cost recovery period r_α and Latin indices i, j, k ... to label hours over the forecast period. Capital Latin letters A, B, C ... will be used to label the technology type of different generators where applicable.

Each pricing prototype depends on some set of the following parameters.

h_i	Hourly Ontario Electricity Price (HOEP) in hour i
T_i	Total Ontario electricity demand in hour i
d_i	Total class B Ontario electricity demand in hour i
C_α	Total class B global adjustment (GA) cost in cost recovery period r_α

Total class B Ontario electricity demand in cost recovery period r_α is therefore defined as

$$D_\alpha = \sum_{i \in r_\alpha} d_i.$$

The criteria for any pricing profile $p_{i\alpha}$ to fully recover revenue from all class B consumers during cost recovery period r_α can then be expressed as

$$\sum_{i \in r_\alpha} p_{i\alpha} d_i = \sum_{i \in r_\alpha} h_i d_i + C_\alpha \qquad \text{(Equation CR)}$$

Note that, except where indicated otherwise, OEB staff use an annual cost recovery period r_α where α labels the forecast calendar year 2018-2031.

Status Quo

The status quo pricing profile is a simplified version of class B pricing in place at the time of writing this paper and is used as a baseline against which all other pricing profiles are compared for the purposes of estimating demand response impact. Class B consumers are divided into two groups: those on the (RPP and all other consumers, called non-RPP class B consumers.

OEB staff assume that all RPP consumers are charged TOU prices where the set of hours defining on-, mid- and off-peak hours are

$$\left.\begin{array}{lcc} S_{\text{on}} & = & \{\text{hours on non-holiday weekdays 11am-5pm}\} \\ S_{\text{mid}} & = & \{\text{hours on non-holiday weekdays 7am-11am and 5pm-7pm}\} \\ S_{\text{off}} & = & \{\text{hours not in } S_{\text{on}} \text{ or } S_{\text{mid}}\} \end{array}\right\} \text{, days in May-Oct}$$

$$\left.\begin{array}{lcc} S_{\text{on}} & = & \{\text{hours on non-holiday weekdays 7am-11am and 5pm-7pm}\} \\ S_{\text{mid}} & = & \{\text{hours on non-holiday weekdays 11am-5pm}\} \\ S_{\text{off}} & = & \{\text{hours not in } S_{\text{on}} \text{ or } S_{\text{mid}}\} \end{array}\right\} \text{, days in Jan-Apr, Nov, Dec}$$

These are the same periods shown in Figure 48. The status quo pricing for RPP consumers is then defined as

$$p_{i\alpha} = \begin{cases} t_\alpha & , i \in S_{\text{off}} \\ \dfrac{3}{2} t_\alpha & , i \in S_{\text{mid}} \\ 2t_\alpha & , i \in S_{\text{on}} \end{cases} \quad \text{RPP consumers}$$

where t_α is chosen so as to recover market and GA costs attributed to RPP consumers. Note that this is different from the RPP as defined at the time of writing where prices are chosen so as to recover costs over the period of May to April of the following year. The calendar year was chosen as the cost recovery period so as to align with the cost recovery period of most other prototypes studied in this paper.

For non-RPP consumers, the status quo price is defined as

$$p_{i\alpha} = h_i + \frac{C_\alpha}{D_\alpha} \quad \text{non-RPP consumers}$$

where the cost recovery period r_α represents each calendar month over the forecast period, labeled by α. That is, RPP status quo prices are defined to recover costs over each calendar year whereas non-RPP status quo prices are defined to recover costs over each calendar month.

While the status quo price segments class B consumers into RPP and non-RPP groups, charging each group a different price, all other pricing prototypes below are defined to be foundational prices that apply to all class B consumers without any distinction between RPP and non-RPP. All costs attributed to Class B consumers are recovered through each prototype without any further distinction of consumers.

In the analysis of the economic efficiency of each pricing prototype, OEB staff define the following references to refer to these two status quo scenarios.

Table 8: Technical definition of status quo pricing examples.

Reference	Pricing prototype	Description	Adjustable Parameters
SQ RPP TOU	Status Quo	Time of use pricing applied to RPP consumers	NA
SQ NonRPP	Status Quo	HOEP + flat monthly GA price applied to non-RPP consumers	NA

Flat

The flat pricing profile is defined to be the least dynamic prototype, charging consumers the same price in all hours over the cost recovery period. The only adjustable parameter in the flat prototype is the length of the cost recovery period r_α.

Table 9: Adjustable parameters for the flat pricing prototype.

r_α	Timing and duration of cost recovery period

The flat pricing prototype is a single price in all hours over each cost recovery period defined as

$$p_{i\alpha} = \frac{\sum_{j \in r_\alpha} h_j d_j + C_\alpha}{D_\alpha} \quad \text{, for all } i \in r_\alpha.$$

This definition automatically satisfies the cost recovery equation above (Equation CR).

OEB staff only consider one example of the flat pricing prototype in this analysis.

Table 10: Technical definition of flat pricing examples.

Reference	Pricing prototype	Description	Adjustable Parameters
Flat - Year	Flat	Flat pricing over an annual cost recovery period	Annual cost recovery period r_α for each calendar year

TOU

The TOU pricing prototype is a natural extension of the status quo RPP price defined above but applied to all class B consumers. This prototype has the following adjustable parameters.

Table 11: Adjustable parameters for the TOU pricing examples.

r_α	Timing and duration of cost recovery periods
$S_{\text{off}}, S_{\text{mid}}, S_{\text{on}}$	Timing and duration of off-, mid- and on-peak periods
$\delta_{\text{mid}}, \delta_{\text{on}}$	Ratio of mid:off-peak price and on:off-peak price respectively

The TOU price is defined as

$$p_{i\alpha} = \begin{cases} t_\alpha & , i \in S_{\text{off}} \\ \delta_{\text{mid}} t_\alpha & , i \in S_{\text{mid}} \\ \delta_{\text{on}} t_\alpha & , i \in S_{\text{on}} \end{cases}$$

where t_α is chosen so as to satisfy equation (Equation CR) for each cost recovery period r_α.

The following examples are used to estimate the economic efficiency of the TOU pricing prototype relative to other prototypes under consideration.

Table 12: Technical definition of examples of the TOU pricing prototype used to estimate relative economic efficiency.

Reference	Pricing prototype	Description	Adjustable Parameters
TOU - 2-1	Time of Use	On-to-off peak ratio of 2:1	Annual cost recovery period r_α for each calendar year; $S_{\mathrm{on}}, S_{\mathrm{mid}}, S_{\mathrm{off}}$ defined as in SQ RPP TOU scenario; $\delta_{\mathrm{mid}} = 3/2$; $\delta_{\mathrm{on}} = 2$
TOU - 4-1	Time of Use	On-to-off peak ratio of 4:1	Annual cost recovery period r_α for each calendar year; $S_{\mathrm{on}}, S_{\mathrm{mid}}, S_{\mathrm{off}}$ defined as in SQ RPP TOU scenario; $\delta_{\mathrm{mid}} = 2$; $\delta_{\mathrm{on}} = 4$

Demand-Shaped

The demand-shaped pricing prototype is designed so as to be directly correlated with total Ontario demand T_i in each hour i. That is, prices are high when demand is high, and prices are low when demand is low. The primary adjustable parameter here is the degree to which price fluctuates relative to electricity demand.

Table 13: Adjustable parameters for the demand-shaped pricing prototype.

r_α	Timing and duration of cost recovery period
w	The power-law dependence of price on Ontario demand

The demand-shaped price is defined as

$$p_{i\alpha} = h_i + \frac{C_\alpha}{D_\alpha}\left(\frac{T_i}{d_\alpha^*}\right)^w$$

where d_α^* is chosen so as to satisfy equation (Equation CR) for each cost recovery period r_α.

The following two examples of the demand-shaped pricing prototype are defined for the purposes of estimating its economic efficiency relative to examples of other pricing prototypes.

Table 14: Technical definition of examples of the TOU pricing prototype used for the purpose of estimating relative economic efficiency.

Reference	Pricing prototype	Description	Adjustable Parameters
Demand - exp2	Demand-shaped	HOEP + hourly GA price weakly correlated with Ontario demand	Annual cost recovery period r_α for each calendar year; $w = 2$
Demand- exp6	Demand-shaped	HOEP + hourly GA price strongly correlated with Ontario demand	Annual cost recovery period r_α for each calendar year; $w = 6$

Supply-Shaped

The supply-shaped pricing prototype is designed so that the GA costs of different generators are recovered in the hours in which those generators produce electricity. In principle, this could be done for each generator individually or for groups of generators that share similar characteristics. How each generator class is defined is the primary adjustable parameter in this prototype.

Table 15: Adjustable parameters in the supply-shaped pricing prototype.

r_α	Timing and duration of cost recovery period
N_{gen}	The number of different generator categories and the character of each prototype

OEB staff use capital Latin letters A, B, C ... as indices to label each generator category, taking values $0, 1, 2 \ldots N_{\text{gen}}$. OEB staff further define $C_{A\alpha}$ as the total class B GA cost over cost recovery period r_α for generator category A. OEB staff define the parameter $C_{0\alpha}$ with $A = 0$ as all class B GA costs that are not shaped but, instead, recovered via a flat price in all hours over the cost recovery period r_α. $C_{0\alpha}$ always includes all class B non-generator GA costs as well as those generator costs chosen not to be shaped. Given this definition, OEB staff see that

$$C_\alpha = \sum_{A=0}^{N_{\text{gen}}} C_{A\alpha}$$

The quantities q_{Ai} indicate the total generation by generators in category A in hour i.

Given these parameter definitions, the supply-shaped price is defined as

$$p_{i\alpha} = h_i + \frac{C_{0\alpha}}{D_\alpha} + \frac{1}{d_\alpha^*} \sum_{A=1}^{N_{\text{gen}}} C_{A\alpha} \frac{q_{Ai}}{\sum_{j \in r_\alpha} q_{Aj}}$$

where d_α^* is chosen so as to satisfy equation (Equation CR) for each cost recovery period r_α.

The following two examples of the supply-shaped pricing prototype are defined for the purposes of estimating its economic efficiency relative to examples of other pricing prototypes.

Table 16: Technical definition of examples of the supply-shaped pricing prototype used to estimate its economic efficiency relative to examples of other pricing prototypes.

Reference	Pricing prototype	Description	Adjustable Parameters
Supply - all	Supply-shaped	HOEP + GA price correlated to hourly generation across all technology categories	Annual cost recovery period r_α for each calendar year; $N_{\text{gen}} = 5$ for generator categories nuclear, hydro, gas, solar and wind
Supply - NucHydGas	Supply-shaped	HOEP + GA price correlated to hourly nuclear, hydro and gas generation	Annual cost recovery period r_α for each calendar year; $N_{\text{gen}} = 3$ for generator categories nuclear, hydro and gas

In order to show the contribution of each generator technology type to the supply-shaped price, below OEB staff plot the hourly supply-shaped price for each of these two examples on a series of three indicative high demand days. These graphs show the motivation for the second scenario where wind and solar generation is not shaped. When wind and solar costs are incorporated into the electricity price at the time of generation, OEB staff see that peak prices will often occur during periods of peak solar generation, which does not often align with periods of peak demand. Further, solar and wind generation is variable and typically non-dispatchable so it may be desired to unlink such uncontrollable factors to the electricity price in any given hour.

Figure 46: Hourly price of the "Supply - all" example of the supply-shaped pricing prototype over a three-day high-demand period.

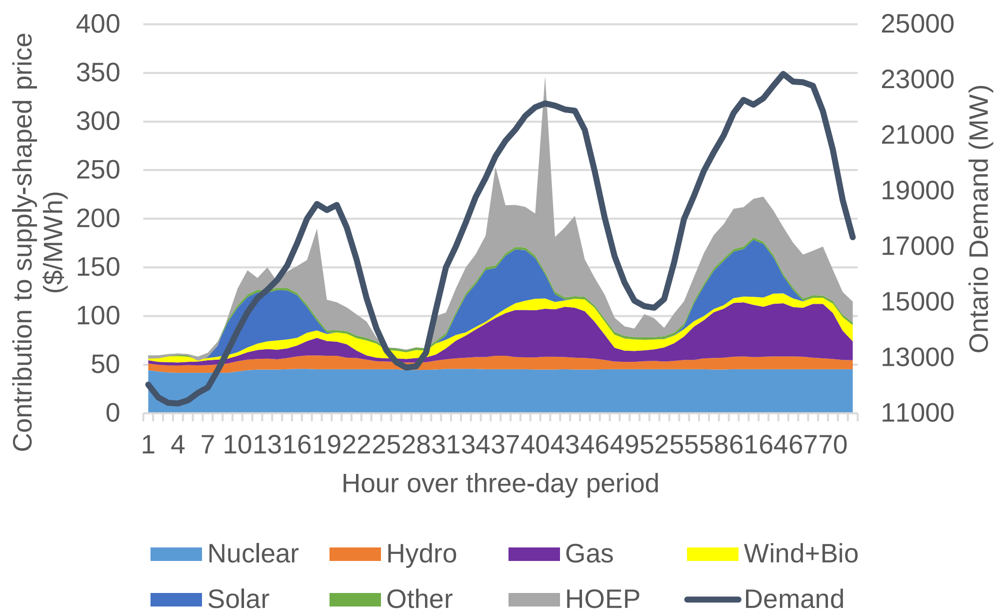
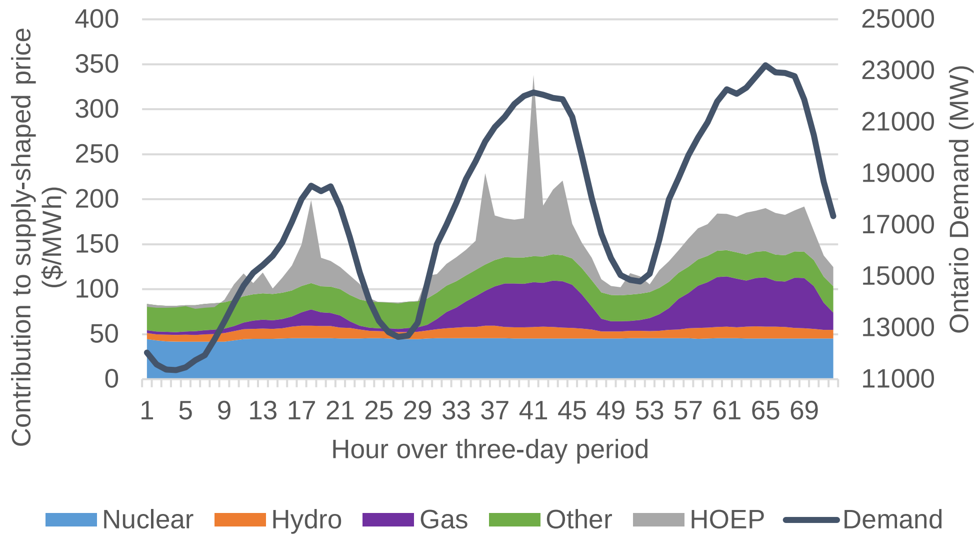


Figure 47: Hourly price of the "Supply - NucHydGas" example of the supply-shaped pricing prototype over a three-day high-demand period.



High N

The high N pricing prototype is designed to be a generalization of the price experienced by participants in the ICI but applied to all class B consumers. Whereas GA costs are recovered from ICI consumers based on their electricity consumption during the 5 highest electricity demand hours within a 12-month base period, the high N pricing prototype recovers GA costs from class B consumers based on their consumption during the N highest demand hours within each cost recovery period r_α.

For ICI consumers, their consumption during the 5 highest electricity demand hours in the base period determines how much they are charged for GA in the *subsequent* 12-month period following the base period. One could imagine defining a similar type of cost recovery mechanism for the high N pricing prototype as well. However, regardless of when the costs are actually recovered, the effect of the ICI pricing program is to create an *effective* price that is much higher in the 5 highest demand hours, regardless of when the costs are actually recovered. Therefore, in order to simplify the analysis, OEB staff define the high N pricing prototype using this effective price, assuming that it is charged in real time so as to recover the GA costs within the cost recovery period in which the prices are defined.

In addition to the number of highest demand hours over which GA costs are recovered, OEB staff also allow for only a fraction of GA costs to be recovered in this way so as to avoid obscenely high prices during the highest N hours.

Table 17: Adjustable parameters in the high N pricing prototype.

r_α	Timing and duration of cost recovery period
N	The number of highest demand hours over which GA costs are recovered
σ	The fraction of total class B GA cost to be included in the effective High-N price

OEB staff define $S_{N\alpha}$ as the set of N hours that experience the highest total Ontario electricity demand during cost recovery period r_α. The high N price is then defined as

$$p_{i\alpha} = \begin{cases} h_i + (1-\sigma)\dfrac{C_\alpha}{D_\alpha} + \sigma\dfrac{C_\alpha}{\sum_{j \in S_{N\alpha}} d_j} & , i \in S_{N\alpha} \\ h_i + (1-\sigma)\dfrac{C_\alpha}{D_\alpha} & , \text{otherwise.} \end{cases}$$

By definition, these prices satisfy the cost recovery equation (Equation CR) in each cost recovery period r_α.

The following two examples of the high N pricing prototype are defined for the purpose of estimating its economic efficiency relative to examples of other pricing prototypes.

Table 18: Technical definition of examples of the supply-shaped pricing prototype used to estimate its economic efficiency relative to examples of other pricing prototypes.

Reference	Pricing prototype	Description	Adjustable Parameters
HiN - 200	High N	HOEP + flat monthly GA price + increased GA price in the highest 200 demand hours	Annual cost recovery period r_α for each calendar year; $N = 200$; $\sigma = 1/2$
HiN - 2,000	High N	HOEP + flat monthly GA price + increased GA price in the highest 2,000 demand hours	Annual cost recovery period r_α for each calendar year, $N = 2{,}000$; $\sigma = 1/2$

B. Electricity Pricing in Ontario

There are currently several ways in which electricity is charged to end-use consumers in Ontario depending on the type of consumer, the magnitude of electricity consumption and on decisions made by each consumer as shown in Table 19 and Table 20. Taken together, the prices charged to consumers for electricity are designed to recover[19]

1. The total cost of revenues paid to generators and other market participants through the real-time electricity market which defines the HOEP and

2. The total cost of revenues paid through the GA for contracts, regulated rates paid for generation and for conservation and demand management programs.

Table 19: Criteria and description of class A electricity pricing.

Class A Pricing			
Pricing Plan	Industrial Conservation Initiative (ICI)		
Average monthly peak demand	500 kW - 999 kW	1,000 kW - 4,999 kW	5,000+ kW
Criteria for Pricing Plan	NAICS beginning with "31", "32", "33", "1114" Opt in	Opt in	Does not opt out
Electricity price charged to consumers	HOEP plus a non-volumetric GA charge based on share of consumer's consumption in the 5 peak demand hours during the previous base period		
GA Cost Recovery Period	One month		

[19] Note that, starting in July 2017, electricity prices for consumers eligible for the RPP were no longer defined so as to recover market and GA costs but, instead, to achieve a targeted reduction in the average bill for a proxy consumer of Toronto Hydro and to ensure such a bill increases only by the rate of inflation year over year.

Table 20: Criteria and description of class B electricity pricing.

Class B Pricing				
Pricing Plan	**Regulated Price Plan**		**Retail Contract**	**Non-RPP class B**
	Time-of-use	**Tiered**		
Criteria for pricing plan	Residential consumer or average monthly maximum demand < 50 kW		Consumer's choice	Average monthly maximum demand ≥ 50 kW and not participating in ICI
	Smart meter installed	No smart meter installed		
Electricity price charged to consumers	Off-, mid- and on-peak prices at defined periods each day as set by OEB	Price depends on bulk volume of consumption in month as set by OEB	Retail contract price + flat $/MWh GA charge	Hourly Ontario Electricity Price plus a flat $/MWh GA price
GA Cost Recovery Period	One year (forecast)		One month	One month

The following figure shows the current RPP TOU periods, which will be referred to throughout this paper.

Figure 48: RPP TOU periods as defined at time of writing.

For the purposes of this analysis, class A pricing will be assumed to be defined as it is currently over the entire forecast horizon of 2018-2031. The entire focus of this paper is to examine the way in which class B pricing is currently defined and to analyze alternative ways in which the pricing for class B consumers could be modified.

C. Forecast Data

The analysis presented in this paper utilizes a collection of forecast data for the years 2018-2031. The majority of the data is that which was used in the Long-Term Energy Plan 2017 [16] (LTEP 2017) and was provided to the OEB by the IESO. This appendix provides more detail regarding the data used along with some summarizing statistics regarding the forecasted outlook.

Hourly Ontario Demand

The total hourly demand forecast of all electricity consumers used in the LTEP 2017 is also utilized for this analysis. It is further required to segregate that total demand into the demand attributed to Class A and Class B consumers and to further segregate Class B demand into that attributed to residential consumers, general services consumers with peak demand less than 50kW (GS<50) and the remaining class B general service consumers with consumption between 50 kW and 999 kW (GS 50-999).

The scale factors listed in Table 21 are used to determine the electricity demand attributed to these difference consumer classes on an annual basis. The resulting annual consumption over the forecast period is presented in Figure 49 and the annual peak demand shown in Figure 50.

Table 21: Scale factors used in computing the annual segregation of electricity demand among different consumer classes.

Factor	Value	Source
Fraction of annual Ontario demand attributed to class B consumers	0.7695	IESO assumption used in LTEP 2017 [16]
Fraction of annual Ontario demand attributed to RPP consumers	0.4309	Based on fraction of monthly demand attributed to RPP consumers in October 2016 to September 2017 as reported to the OEB by the IESO
Fraction of annual RPP demand attributed to residential consumers	0.7482	Derived from the 2016 Yearbook of Electricity Distributors [17]

Figure 49: Forecasted annual Ontario consumption segregated by consumer class.

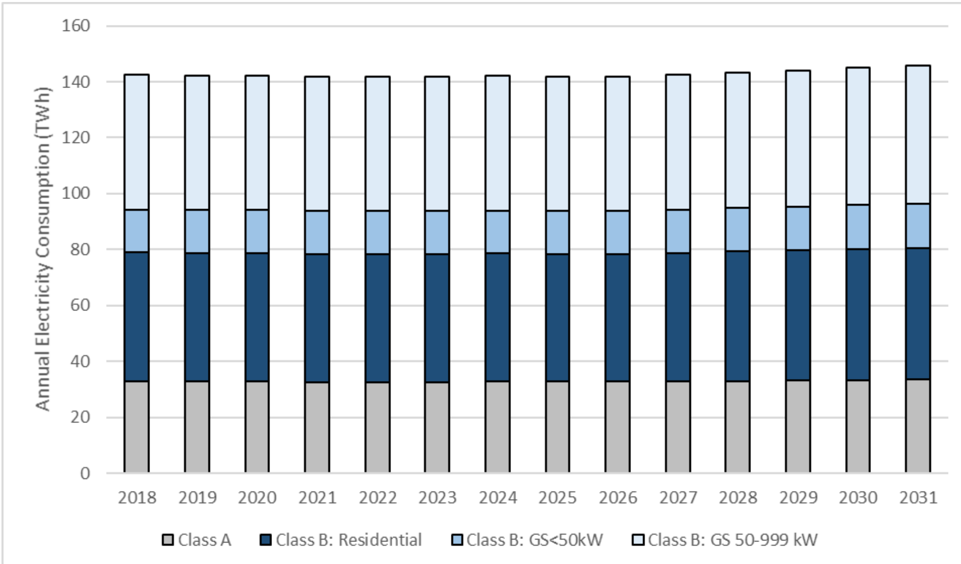
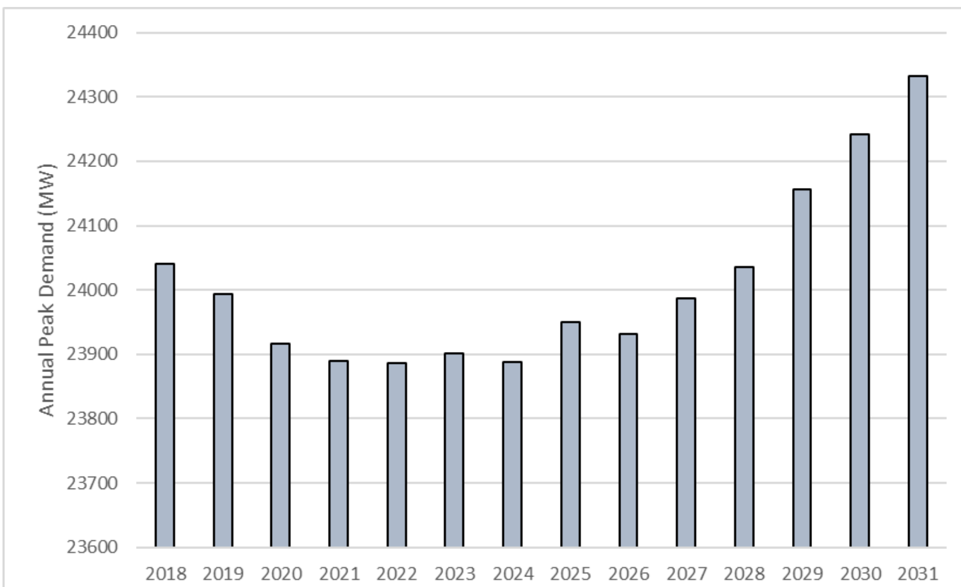


Figure 50: Peak demand in each year over the forecast period.



Beyond this segregation of annual electricity consumption, it is also required to determine the different hourly load shapes for each consumer class. These load shapes are estimated by calculating the average hourly load shape of the residential, GS<50 and GS 50-999 consumer profiles respectively described in Table 22, Table 23, and Table 24.

An example of these relative load shapes on a sample day is shown in Figure 51. These average hourly load shapes for each consumer class are then uniformly scaled in each forecast year so as to achieve the targeted annual consumption described above. The result is an estimate of the hourly load for residential, GS<50 and GS 50-999 consumers respectively over the forecast period.

Table 22: A summary of the set of hourly load profiles for residential consumers.

Distributor	Number of Consumers	Average Monthly Consumption in kWh	Data Year
Toronto Hydro	1,500	638	2015-01-01 through 2015-12-31
Alectra Utilities - Powerstream[20]	311,865	835	2015-08-01 through 2016-07-31
Hydro One – R1 and R2 Distribution Rate Class Only	153,665	1,039	2015-08-01 through 2016-07-31
Hydro One Brampton	127,344	742	2015-10-01 through 2016-09-30
Veridian	92,366	751	2012-01-01 through 2012-12-31

Table 23: A summary of the set of hourly load profiles for GS<50 consumers.

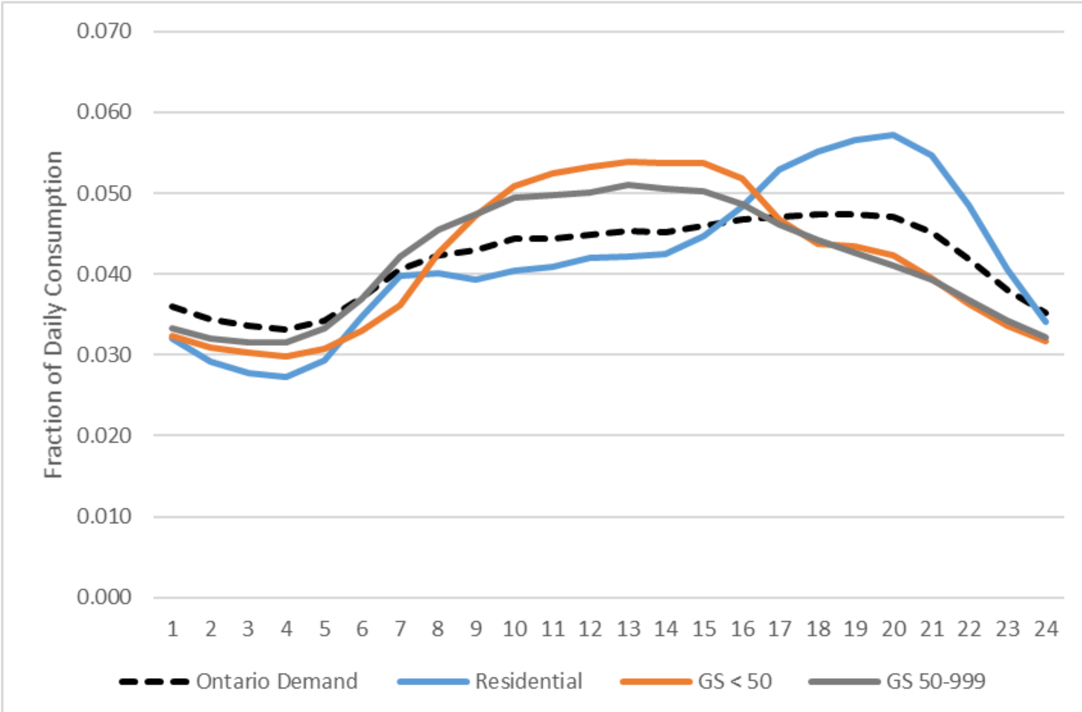
Distributor	Number of Consumers	Average Monthly Consumption in kWh	Data Year
Hydro One	79,586	1,892	2014
Alectra Utilities[20]	17,427	2,491	2014

Table 24: A summary of the set of hourly load profiles for GS 50 - 999 kW consumers.

Distributor	Number of Consumers	Average Monthly Consumption in kWh	Average Monthly Maximum Demand in kW	Data Year
Toronto Hydro	2,210	164,691	349	2012
Alectra Utilities - Powerstream[20]	526	146,728	341	2014
Hydro One	651	96,258	202	2014
Alectra Utilities - Enersource[21]	304	204,917	440	2014
Horizon	1,115	72,799	175	2014
Hydro Ottawa	1,919	113,192	129	2014
Entegrus	215	57,732	149	2015

[20] The consumers from this data set reside within PowerStream's service territory only.
[21] The consumers in this data set reside within Enersource's service territory only.

Figure 51: Estimated fractional load shapes for a sample summer weekday.



Electricity Supply Costs

As each pricing variant is defined to fully recover both electricity market costs as well as GA costs attributed to class B consumers, an estimate of each of these costs over the forecast period is required. The values for the HOEP and annual class B GA costs used in the analysis of this paper are the same as those calculated by the IESO and used in the LTEP 2017. The average HOEP in each year is shown in Figure 52 and the annual GA costs shown in Figure 53.

Figure 52: Annual demand-weighted average of the HOEP forecast used in this analysis.

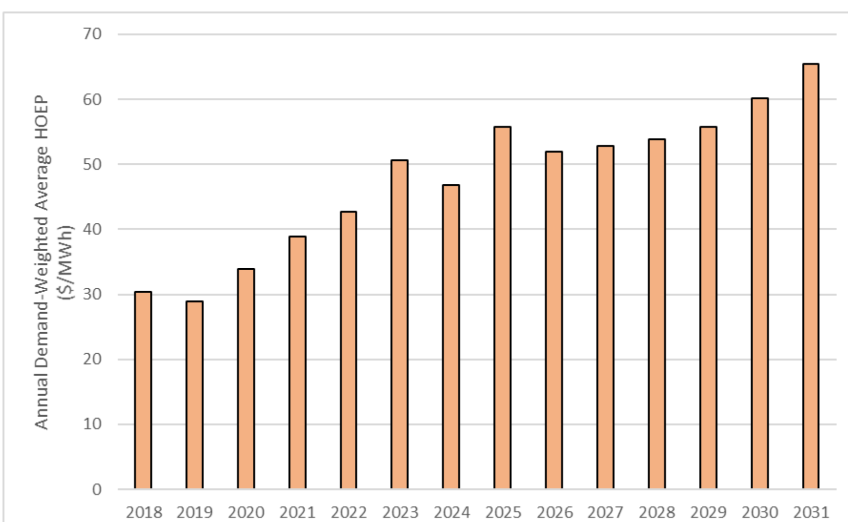
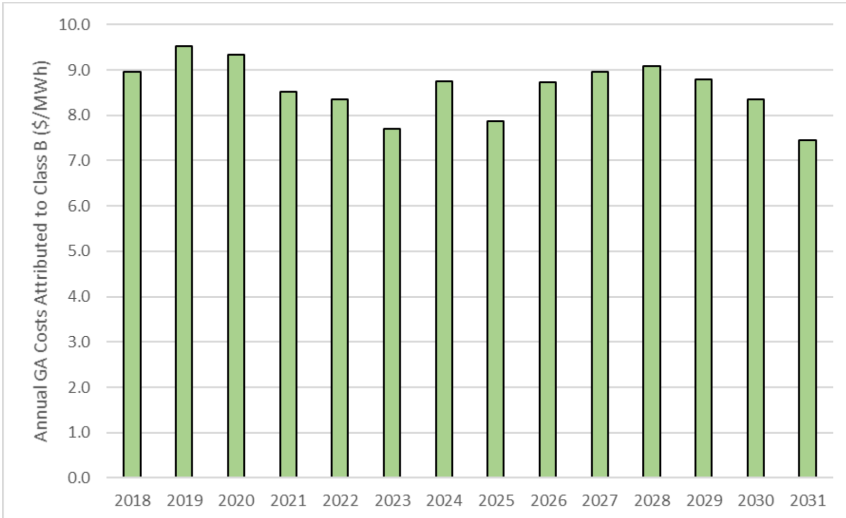


Figure 53: Forecast of annual GA costs attributed to class B consumers used in this analysis.



Avoided Capacity Costs

Part of the calculation of the economic efficiency of each pricing variant involves an estimation of the avoided capacity costs attributed to the expected change in demand in response to each new price. The estimation of these costs is described in section 2.3.2 and shown explicitly in Table 25.

Table 25: Assumed value of avoided capacity due to a change in peak in demand.

Year	Capacity Cost ($/MW-Yr)
2018	$0
2019	$35,883
2020	$71,765
2021	$107,648
2022	$143,531
2023	$146,401
2024	$149,329
2025	$152,316
2026	$155,362
2027	$158,469
2028	$161,639
2029	$164,871
2030	$168,169
2031	$171,532

D. Overview of the Theory and Practice of Electricity Pricing

A good understanding of the work done in the past on electricity pricing plans helps ensure the coherence and integrity of projects such as this one that aims to re-think the RPP and provide new options both for RPP-eligible and non-eligible Class B consumers. OEB staff have identified three broad categories of written work that help inform the analysis described in this paper.

Theory – Peak Load Pricing Literature

Electricity prices have evolved since the 19th century and have been "…driven by social, political, and commercial realities, and were not always set rationally. Then, as now, tariffs were also limited by the technological capabilities of the meter and metering system." [18] In the 1950s and '60s, academic economists asked whether pricing in capital-intensive industries such as electricity could be improved to bring about greater short- and long-run economic efficiency. The theory developed in this period still guides understanding of efficient pricing today.

In electricity, capital – or, capacity – is a public good that is shared by peak and off-peak users in the present, as well as present and future consumers. Demand may be growing or receding over time, and peak and off-peak differences in demand can be important. One level of capacity must serve all these uses; at discrete times the amount of capacity has to change.

What is the best level of capacity to serve current peak and off-peak users, and can a pricing plan help to find that level of capacity? When should the amount of capacity be changed, and can pricing help to ensure this is done correctly? The peak load pricing literature works out the economics of these questions. Not surprisingly, there are trade-offs: the efficient amount of capacity today may imply unused capacity at off-peak, but rationing of capacity at peak. Similarly, efficient provision of capacity for the future may imply unused capacity in the present.

In short, the peak-load pricing literature seeks to optimize the trade-off between the risk of wasted capacity versus the risk of wasted consumer surplus. The key question for prices is how much of the fixed costs of capacity to uplift into the commodity price, and when to do so, so as to optimize this trade-off.

The seminal papers in the peak-load pricing economics literature were written in the 1950s and 1960s. Some authors framed their analyses explicitly for an electricity sector context. In this period, the electricity sector was, in most places, organized as a vertically integrated, monopoly public utility. Thus, the pricing questions analyzed were framed as the setting of an optimal tariff. Other authors wrote for any capital-intensive industry, and their pricing discussions were easy to think of as fluctuating market prices.

As noted earlier, a key topic in these papers is how much of fixed cost to include in the price of the service. Allocative efficiency calls for the most efficient use of existing capacity, while dynamic efficiency calls for optimal decisions on the timing and amounts of investments in new capacity. Thus, how and when to uplift fixed costs into the price of the service turns on how to optimally trade off the risk of wasted capacity versus the risk of wasted consumer surplus – due to rationing existing capacity.

Williamson, O.E., *Peak-Load Pricing and Optimal Capacity under Indivisibility Constraints* [19]

This paper is one of the early works on peak load pricing, and the first to consider optimal choices when capacity is subject to indivisibility constraints – that is when capacity cannot be varied continuously but rather comes in discrete, "lumpy" sizes. When capacity is "lumpy," there is a strong distinction between the short-run and the long-run, and, in particular, between short- and long-run marginal cost.

Steadily Increasing Demand: The paper develops a model with one kind of generation exhibiting fixed short-run, and long-run marginal costs. In this literature, short-run marginal costs (SRMC) are symbolized by b while long-run capacity costs are β, both measured in units of $/MWh. Thus, $\mathrm{SRMC} = b$ and the long-run marginal cost (LRMC) is $\mathrm{LRMC} = b + \beta$. Thus, SRMC is horizontal until the point where capacity is exhausted, at which point it becomes vertical. Williamson shows that it is not optimal to add capacity until demand has risen to the point where price is well above the LRMC. When capacity is added, price falls to a level below LRMC but still above the SRMC. If demand is continually growing, capacity will be added at discrete dates with price oscillating above and below LRMC. On average, price equals LRMC and the industry is just breaking even.

An interesting feature of this outcome is that price is always above SRMC and serves to ration capacity.

Peak and Off-Peak Loads: The paper goes on to analyze the case of demand oscillating between peak and off-peak levels. Williamson derives a demand for capacity curve and shows that optimal capacity is found where this curve intersects with the LRMC curve. Prices in the peak and off-peak periods are then determined where SRMC intersects each demand curve. He finds:

- The peak-load price always exceeds LRMC
- Off-peak price is always below LRMC
- If the off-peak load fails to fully utilize capacity, the off-peak price will be SRMC and the peak period will bear the entire burden of capacity costs.

Crew, M.E., *Peak-Load Pricing and Optimal Capacity: Comment* [20]

Crew's note provides an extension of Williamson's analysis to allow for plants of different technology (a "peaker" plant with a higher operating cost, b1, than the standard plant used in Williamson's model, and a lower capital cost, β1). Thus, the rational system planner could choose between adding another "efficiency unit" of the standard technology – which may take longer to pay off if the standard technology exhibits significant indivisibilities. The peaker plant is assumed to not exhibit significant indivisibilities so that it can be more readily right-sized as compared to the efficiency unit of the standard technology. The peaker may be the better choice, despite having higher average costs (b1 + β1 > b + β).

Thus, Crew's note is a first step in extending Williamson's analysis to consider the mix of generation within the optimal capacity question.

Brown Jr., G.; Johnson, M. Bruce, *Public Utility Pricing and Output under Risk* [21]

Brown and Johnson introduced uncertainty into the analysis of the peak-load pricing question, and came to results that posed a direct challenge to the peak and off-peak pricing solutions that Williamson had reached. Brown and Johnson found that if demand is uncertain, and price and capacity decisions must be made prior to the revelation of the true value of demand, then price should always be set equal to marginal operating costs, b. This would ensure optimal use of capacity in the case of low demand, and would not matter in the case of high demand. If demand turned out to be high, so that it intersects the SRMC curve on its vertical portion, pricing doesn't matter as quantity is constrained by capacity – price cannot influence a higher or lower rate of output, and it will also not influence the total of consumer surplus and net revenue. Thus, the best price to choose ex ante should always be b.

As for the choice of capacity, it can be chosen to maximize a consumer's surplus in the event of high demand.

Thus, rather than having different prices at different times to ration peak and off-peak demands, Brown and Johnson call for a much simpler pricing rule: always set price equal to b.

Brown and Johnson point out that their result can be interpreted as a direct consequence of the fact that capital costs are sunk in their analysis, in a way they are not in the Williamson analysis.

Salkever, David S., *Public Utility Pricing and Output Under Risk: Comment* [22]

Salkever's note extends the Brown and Johnson logic further. The Brown and Johnson approach does not guarantee revenue adequacy as does the Williamson approach. It also highlights the assumption made implicitly in Williamson's model that price would always be the means by which the market clears and available supply is rationed. In other words, Williamson implicitly assumed that available supply is rationed by willingness to pay. Brown and Johnson removed this assumption and thus allowed for other means of rationing available supply when demand would exceed capacity at a given price. Salkever doubles down on the removal of this assumption.

Thus, Salkever finds that the optimal price = b even in a model with no uncertainty if the assumption of rationing by price is dropped. If peak demand intersects the vertical SRMC curve at P1, then any price P2 for which b <= P2 =< P1 also maximizes consumer surplus plus net revenue. If off-peak demand intersects the horizontal portion of SRMC curve, then Price = b is optimal. Thus Price = b is the best single price rule to have. The same logic extends to the case where demand is random, and price must be determined before demand is known.

Turvey, Ralph, *Public Utility Pricing and Output Under Risk: Comment* [23]

Turvey responds to the Brown and Johnson paper (and, implicitly, the Salkever comment) by stating they make the implicit assumption that rationing by some non-price means is always preferable to price rationing when demand is high. Non-price rationing can be very wasteful, inefficient, and irksome in many contexts: lineups, waiting lists, coupon-style rationing and so on. So the assumption that non-price means of rationing demand in excess of capacity is just as good as price rationing needs to be assessed on a case-by-case basis.

Turvey suggests non-price rationing is especially problematic in electricity in that it would imply power cuts – i.e., – blackouts and brownouts. Electricity systems place a high priority on avoiding these outcomes and modern wholesale markets contribute to maintaining reliability in this form by allowing price increases to engage dispatchable loads in voluntarily curtailing consumption, and thus maintaining supply and demand balance.

More generally, one can question whether the notion of risk underlying the discussion here is appropriate for electricity. In these papers, price and capacity decisions must be made before the true value of demand is revealed. In the context of peak and off-peak pricing of electricity, it is as if to say an agent must set tomorrow's peak and off-peak prices without knowing whether the peak and off-peak periods might be reversed from what the agent anticipates. While the exact value of tomorrow's peak is unknown, there is so much regularity and repetition in electricity consumption on a daily or annual basis, peak and off-peak periods are quite well understood. However, when it comes to choosing capacity and price for several years into the future based on current demand growth assumptions, the Brown and Johnson uncertainty re-emerges.

Operationalizing the Theory – Meaning and Measurement of Short- and Long-Run Marginal Cost

Marginal cost is a simple notion in theory, but the measurement of it in a dynamic and capital-intensive sector such as electricity can be much more complicated. Work in this area examines how to assess short- and long-run costs in a sector with various generation technologies, indivisibilities that result in lumpy investment sizes, and ongoing technological change.

The theory of peak load pricing is highly abstract and does not deal with the realities of an actual grid with many different generation technologies, capacity from widely varying vintages, lumpy investments, and so on. The work of Turvey is a corrective to this theoretical over-simplification.

Turvey, R., *Peak-Load Pricing* [24]

In this paper, Turvey accepts the basic findings of the Peak-Load Pricing literature given the assumptions the authors make:

- The optimum requires price to exceed marginal running costs in periods where demand is high, by amounts that both restrict demands to capacity and that sum up over them to equal the marginal cost of capacity.
- In other periods, price must equal marginal running costs.

However, the assumptions made to get these results remove from the discussion many of the most interesting and important issues, in Turvey's view. Turvey groups the assumptions into three groups: costs, demand, and tariff assumptions.

Regarding costs, key assumptions here are:

- Constant marginal running costs – this is very rare.
- Constant incremental capacity costs – this is too oversimplified to be useful.

In only rare cases will the first assumption be true. Differing generation technologies and varying fuel prices over time are only two reasons why system running costs will not be constant. Thus, price should vary on this account. However, varying price to match will make the electricity tariff too complex and costly to administer. Trading off the costs of this complexity against the benefits of accurate, efficient pricing may mean that such a pricing scheme is no longer optimal. (It is worth remembering that Turvey is writing in 1968 – long before power pools, markets, and advanced metering.)

Consider incremental capacity costs in a system growing over time, with many generation technologies, and with technological change so that new generation comes online with cheaper running costs than old. It is not a simple matter. Thus, coming up with a realistic estimate of incremental capacity costs requires knowing or guessing something about the future patterns of demand growth and future changes in technology. Turvey's other paper in this section gets more deeply into this question.

Turvey, R., *What are Marginal Costs and How to Estimate Them* [25]

This paper by Turvey focusses on understanding marginal costs, and costs in general, in the real-world contexts of regulated industries. The paper discusses the difference between the economic concept of costs and accounting concepts. Generally, the economic concept of cost is the right one for making decisions on future courses of action, while accounting costs are important for questions of who should contribute how much to the recovery of these costs – what Turvey considers business or political decisions about perceived fairness.

Turvey provides a simple numerical example of the calculation of marginal cost in an unspecified utility with growing peak and off-peak demands, and a menu of plants available for system expansion. The plants vary in capacity amounts, capacity cost, and operating costs. To meet demand growth and maintain a reserve margin, the optimal sequencing of plant construction, commissioning, and startup must be determined via complex linear programming calculations. Once the optimal system expansion path is determined, marginal costs can be computed.

Turvey discusses the many complicating factors that the real world imposes on the above simplified but still very difficult example. These include the fact that most industries are not characterized by a single output; there are common costs incurred on behalf of all the outputs, and these must be dealt with in the marginal cost calculations; specifying the nature of the change in output giving rise to the change in costs on the margin is never straightforward; and so on. In short, costs in the real world are never as simple as the LRMC = b + β formulation in the basic economic theory.

One key takeaway from the Turvey work is to not fall prey to a false sense of precision when applying concepts from basic economic theory to the questions this discussion paper deals with. This paper does attempt to assess the economic efficiency properties of several pricing plan prototypes, but clearly the kinds of cost calculations that Turvey expresses are far beyond the scope of this work. The economic efficiency analyses herein can best be thought of as sketches rather than precise planning estimates of cost and benefit.

Market Surveillance Administrator, Alberta *A Comparison of the Long-Run Marginal Cost and Price of Electricity in Alberta* [26]

In this 2012 report, the Alberta Market Surveillance Administrator (AMSA) developed measures of LRMC and compares them to likely price distribution outcomes in order to assess the economic performance of the Alberta wholesale electricity market. The study takes the view that the market can be considered effectively competitive if (among other tests) price outcomes are likely to be just enough to cover the fixed costs of investment plus operating costs. Put differently, prices should average out to a rough equality with LRMC for the market to be considered both sustainable and reasonably competitive.

The study surveys various methods of measuring LRMC, mostly related to the approaches discussed in Turvey's work. However, acknowledging the difficulties of actually implementing these methods, the study develops a simpler alternative based on the Levelized Unit Economic Cost (LUEC) concept, which computes the annual costs of a greenfield generation investment. The AMSA acknowledges that this kind of simplification is at some distance from the Turvey-style approaches, which will consider the least-cost means of meeting a permanent demand increment. The Turvey approach will consider many options such as using existing generation more intensively, and extending the useful life of existing generation, as well as outright new build. Thus, the AMSA interprets the LUEC method as the high-cost upper bound of a LRMC calculation.

The MSA concluded that price outcomes were likely to be in line with LUEC estimates of LRMC so that the market could be viewed as effectively competitive.

This study underscores the takeaway noted above from Turvey's work on the importance of avoiding a false sense of precision when assessing economic efficiency in this context. One way to think about this in the current context is to treat the economic efficiency analysis performed on the pricing prototypes discussed in this paper as a check for clearly outlying pricing plans – those that appear strongly superior to, or strongly inferior to, the status quo.

Operationalizing the Theory – Pricing Plans in Use Today

Current metering technology allows for a range of pricing options: flat rates, TOU rates, critical peak, dynamic pricing and so on. How are they performing, and what do they tell us about consumer response to changing electricity prices?

Faruqui, A. et al. *Time-Varying and Dynamic Rate Design* [27]

This paper provides a comprehensive survey of issues around the pricing of electricity at the retail level when consumers have the metering infrastructure that allows for time-varying and dynamic prices. The widespread installation of smart metering technology has enabled a wide variety of alternatives to traditional flat rate designs to be tested in pilots and then implemented. Several benefits can be expected from well-designed pilots and subsequently implemented pricing plans. These include:

- Avoided or deferred resource costs as load factors decrease in response to higher peak charges
- Greater fairness – if one accepts cost causality as a basis for fair pricing, then time-varying prices can better align high-cost peak periods with consumers bills
- Consumer bill reductions – at least for responsive consumers in the short-run. In the long-run, deferred costs can lower bills for all
- Facilitating deployment of distributed resources: Time-varying rates, in combination with net metering, can change the economics of micro-scale distributed energy resources.

At the same time, dynamic pricing can entail risks for some consumers. For example, those who are less able to change consumption patterns may end up experiencing financial harm as a result of time-varying prices.

Alternative time-varying pricing plans involve costs as well as benefits:

- The incremental net costs of the new metering technology that is required
- The loss of economic welfare associated with reducing consumption in high-priced hours or shifting consumption to lower-priced hours.

The paper goes on to describe the key design features of several different types of time-varying and dynamic pricing plans, along with their advantages and disadvantages. Key points include the simplicity of TOU rates with their fixed schedule of high- and low-priced hours, and the fact that Critical Peak Pricing plans will limit the number of hours in a year when the highest prices will prevail.

Key design criteria are assessed, as are the pitfalls in designing pricing pilots – a step the authors state is essential.

From there the paper discusses full deployments of time-varying rates in four case studies from around the world. In California, the introduction of Critical Peak Pricing in 2008, on an opt-in basis, led to a 14% reduction in peak demand in the relevant service territory. A very interesting finding is that the peak reduction effect reflects substitution to low-priced periods rather than a conservation effect. This finding is apparently typical, and leads the study to conclude that time-varying pricing will affect the demand for capacity more than it will affect the demand for energy. This in turn has potential implications for time-varying pricing as an environmental measure.

The Critical Peak Pricing plan in France led to total peak reductions of 450 MW, driven in part by 45% peak reductions on “red days” from those who opted into the program – results that the study attributes to the longevity of the program and extensive deployment of load control technology and consumer education.

The paper concludes by synthesizing all of the previous sections into a blueprint for developing time-varying rate pilots and, ultimately, general implementation. Key points here are to benefit from lessons learned in other jurisdictions, and to carry out plenty of consumer outreach to understand how consumers will react to various rate designs and the potential bill savings they can offer.

Market Surveillance Panel, *Monitoring Report on the IESO-Administered Electricity Markets* [28]

Although Ontario's ICI is outside of the scope of this work on Class B pricing, the pricing concepts that underlay it and the analysis done to date of the ICI are very much in the spirit of this work. This is especially true given that one of the pricing prototypes discussed in this report is closely related to the ICI.

For its June 2013 Monitoring Report, the OEB's Market Surveillance Panel (MSP) carried out an econometric study of the ICI to assess its operation and whether or not it contributed to economic efficiency.

The MSP found that in 2011 and 2012, Class A loads in Ontario reduced their consumption by about 379 MW in the top 1% peak consumption hours in those years. Although a sizable amount, and very noticeable to the eye in the charts provided in the report, this reduction in Class A consumption is actually small in comparison to the size of the incentive provided by the ICI, and suggestive of a rather small own-price elasticity of demand.

In parallel to this, the MSP found that Class A consumption increased only modestly in off-peak hours, even in the face of a significant reduction in off-peak prices brought about by the ICI mechanism. Again, this finding is consistent with a relatively low own-price elasticity of demand for electricity consumption by Class A consumers.

To assess the ICI's likely effects on short-run economic efficiency for Class A consumers, the MSP calculated likely efficiency losses during peak hours (due to effective prices in these hours that are far in excess of marginal production costs) and compared these to likely efficiency gains during off-peak hours when the ICI lowered Class A prices towards marginal costs. Although the calculations are rough and cannot be thought of as conclusive, on balance the strong suggestion was that the peak hour efficiency losses outweighed the efficiency gains in the rest of the year. To this can be added the effects of the ICI on Class B consumer surplus. Although the MSP did not have the data to enable such an estimate, they viewed the effect as likely to be negative, as the cost-shifting effect of the ICI raised prices for Class B further away from marginal costs.

The MSP did not attempt to measure long-term efficiency effects from the ICI beyond noting that in the excess supply conditions prevailing at the time, the value of reduced peak consumption in terms of deferred investment costs is low. At the same time, the MSP notes that the ICI mechanism will not deliver as strong a peak-reducing incentive when tighter supply conditions return.

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