ONTARIO ENERGY BOARD

Report Back to the Minister

Dynamic Pricing for Non-RPP Class B Electricity Customers

March 2025

Ontario
Energy
Board

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LIST OF ACRONYMS

AMI	Advanced Metering Infrastructure
AQEW	Allocated Quantity of Energy Withdrawn
CEP	Comprehensive Electricity Plan
CHEC	Cornerstone Hydro Electric Concepts
CPP	Critical Peak Pricing
DBHP	Demand-Based Hourly Price
DER	Distributed Energy Resource
EDA	Electricity Distributors Association
ESF	Electricity Storage Facility
GA	Global Adjustment
GS	General Service
HOEP	Hourly Ontario Energy Price
HVAC	Heating, Ventilation and Air Conditioning
ICI	Industrial Conservation Initiative
IESO	Independent Electricity System Operator
LDC	Local Distribution Company
MSP	Market Surveillance Panel
MW	Megawatt
MWh	Megawatt hour
OEB	Ontario Energy Board
OPG	Ontario Power Generation
RPP	Regulated Price Plan
RTP	Real-Time Price
TOU	Time-of-Use
ULO	Ultra-Low Overnight

EXECUTIVE SUMMARY

The Ontario Energy Board is pleased to submit this report to the Minister of Energy and Electrification with a recommendation for an opt-in dynamic electricity price plan for Class B customers that are not eligible for the Regulated Price Plan (Non-RPP Class B customers) that will enable these customers with unique business operations to better manage their energy costs.

In November 2021, the Minister of Energy requested that the OEB collaborate with the IESO to develop a plan to design and implement a dynamic electricity pricing pilot to assess the benefits for Non-RPP Class B customers.[1] In October 2022, the Minister requested that the OEB begin the pilot application process following stakeholder consultation.[2] From 2022-2023, the OEB worked closely with stakeholders to develop and launch a Pilot Program for this initiative, but no applications were received by the deadline. In place of a Pilot Program, the OEB designed a research-driven and consultation-based approach to identify alternative price plans for Non-RPP Class B customers.

Non-RPP Class B customers represent approximately 50,000 electricity consumers in Ontario. This is a diverse group that includes mid-size commercial and light industrial businesses, such as large retail stores, office buildings, schools, hospitals and small manufacturers. These customers have no regulated alternative price options available to them, except for those eligible to participate in the Industrial Conservation Initiative (ICI).

The OEB's approach to dynamic pricing was predicated on its desire to enable customer choice and better align Non-RPP Class B customers' price signal with provincial costs. According to the cost-causation principle, those responsible for incurring a cost should bear that cost. In other words, electricity consumers should pay for electricity in proportion to their usage of the system and share of its costs. By providing options that are more reflective of system costs, customers are incentivized to make investment decisions that promote affordability through economic efficiency and participate in demand management and electricity conservation to keep system costs down in the long run.

[1] The November 2021 Mandate Letter to the Ontario Energy Board can be found at: https://www.oeb.ca/sites/default/files/mandate-letter-from-the-Minister-of-Energy-20211115-en.pdf.

[2] The October 2022 Letter of Direction (formerly Mandate Letter) to the Ontario Energy Board can be found at: https://www.oeb.ca/sites/default/files/letter-of-direction-from-the-Minister-of-Energy-20221021.pdf

The cost of Ontario's electricity generation supply is paid for by the wholesale market price and the Global Adjustment (GA). The GA is primarily used to pay for out-of-market electricity supply costs, the difference between generation costs and the wholesale market price. From 2015 through 2023, approximately 75% of Ontario's electricity supply costs were paid for by the GA.[3] As a result, the GA makes up a significant portion of electricity bills in the province.

Currently, Non-RPP Class B customers pay commodity costs via the wholesale market price and the Class B GA rate published monthly by the Independent Electricity System Operator (IESO). The wholesale market price changes hourly and reflects supply and demand conditions as well as bids and offers settled in the wholesale market. The Class B GA rate, on the other hand, does not vary throughout the month. It allocates GA costs to customers based on their total electricity consumption each month, regardless of when their consumption occurs.

Since the GA is primarily composed of out-of-market costs, the Class B GA rate is high when average wholesale market prices are low, and low when average wholesale market prices are high. This distorts the overall price signal Non-RPP Class B customers receive. It does not communicate to them when electricity is abundant and less expensive, or when electricity supply conditions tighten and prices rise. Therefore, it does not encourage efficient use of electricity system assets.

The OEB has conducted research and stakeholder engagement activities to identify alternative opt-in price plans for this group of customers through which to pay the GA. This work includes an update to an OEB Staff Research Paper from February 2019 evaluating economic efficiency of alternative rates,[4] an analysis of bill impacts of alternative rates, interviews with customers and consumer associations, and discussions with industry stakeholders including local distribution companies (LDCs) and the IESO. Price plan design and selection were driven by three objectives: cost reflectiveness, minimization of short-term disruption and feasible implementation.

The OEB identified two alternative GA price plans for this customer group:

- **Non-RPP Time-of-Use (TOU):** Defined price depending on the period

[3] This estimate is calculated from the IESO's Data Directory, Historical Hourly Ontario Energy Price Data and Global Adjustment Report, which can be found at: https://www.ieso.ca/Power-Data/Data-Directory.

[4] The 2019 OEB Staff Paper can be found at: https://www.oeb.ca/sites/default/files/rpp-roadmap-staff-research-paper-20190228.pdf.

of day.

- **Real-Time Price (RTP):** Hourly price that correlates with Ontario demand.

These price plans are designed to be optional and only apply to the GA portion of the commodity cost for which participating customers are billed. If offered, Non-RPP Class B customers would continue to pay all other electricity costs (e.g., wholesale market prices, distribution costs) as they do today.

There was no clear preference among stakeholders towards one alternative GA price plan. Customers who supported predictability and certainty preferred Non-RPP TOU, while those whose operations could tolerate more flexibility and variability were amenable to the RTP. For LDCs and customers, the simplicity of Non-RPP TOU, prior familiarity and reduced complexity with implementing TOU price plans, and perceptions of higher potential customer uptake led them to favour Non-RPP TOU.

Both price plans would reduce bulk-system peak demand and promote economic efficiency in the long term. The Non-RPP TOU plan provides a predictable and simplified cost-reflective price signal. Though this option is less cost reflective than the RTP, the lower coincident peak demand reduction per adopter is counteracted by higher estimated adoption. During OEB engagements, several stakeholders stated an overall stronger preference for Non-RPP TOU, citing its predictability and certainty, potential savings for some customers, higher potential customer uptake and relative lack of implementation complexities.

As the more cost-reflective option, Real-Time Pricing could deliver higher coincident peak demand reduction per adopter. However, some stakeholders pointed to potential lower perceived customer uptake of the Real-time Price consistent with the results of the bill impact analysis. The OEB also identified complexity concerns for customer communication, local distribution company billing and settlement upgrades and automating day-ahead price setting for the implementation of Real-time Price. These technical implementation challenges should be thoroughly tested before moving forward with the Real-time Price.

Through this initiative, the OEB also identified that variance, which is the difference between forecasted and collected amounts, is likely to be more difficult to control for any price plan that recovers only GA costs compared to a price plan that recovers all commodity costs (like the RPP). This means that there is a risk of accruing higher variances, which could lead to rate volatility. To mitigate against such, the OEB recommends considering adjusting the price plans to recover all commodity costs (wholesale market costs and GA) as opposed to GA only. Further stakeholder consultation is recommended to assess this approach.

Based on research and stakeholder input, the OEB recommends that the Minister of Energy and Electrification **take steps to implement a Non-RPP TOU alternative price plan** for Non-RPP Class B customers in a phased approach. Next steps would include an exploration of how to resolve variance challenges as well as identifying in greater detail the steps needed to be taken by the Ministry of Energy and Electrification, IESO, OEB and LDCs.

The OEB is available to assist with the development of any implementation plans for a new price plan. Alternative price plan rollout would require further decisions and action from the Ministry of Energy and Electrification, IESO, OEB and LDCs, prior to implementation. This would include determining eligibility, designing settlement factors, making required regulatory changes, and updating the GA settlement process. Implementation timelines would need to be assessed with each party.

Overall, each price plan would enable customer choice for a group without any regulated price plan option and allow these customers to manage their energy costs more efficiently, supporting the unique nature of their business operations. The Non-RPP TOU provides more predictable and stable electricity prices than the status quo Class B GA rate while better reflecting the costs of supply.

1 INTRODUCTION

The energy transition presents opportunities to leverage the province's energy advantage through the provision of more affordable, reliable and clean energy. As Ontario's grid evolves, the OEB plays an important role in developing innovative pricing mechanisms that not only provide customers with opportunities to reduce their electricity bills, but also ensure overall energy system resiliency and efficiency.

One such pricing mechanism is dynamic electricity pricing. Dynamic pricing incentivizes customers to adjust their electricity usage patterns and alleviate grid stress during peak electricity demand periods. By encouraging customers to reduce their consumption when it is most costly, dynamic pricing contributes to a more efficient energy system. This will help the sector navigate the complexities of the energy transition and a projected 75% increase in demand over the next 25 years.[5]

In recent years, choice for residential and small business customers has been expanded through the introduction of the Tiered and Ultra-Low Overnight (ULO) price plans. Large businesses, also referred to as Class A customers, can manage their electricity costs through participation in the Industrial Conservation Initiative (ICI).[6] Many Class B customers that are not eligible for the RPP (Non-RPP Class B customers) have no regulated, alternative GA price plans available to them, except for those eligible to participate in the ICI program.

1.1 Background

In July 2022, the OEB began developing a Pilot Program that would "offer an opportunity to assess the potential benefits of dynamic electricity pricing and its ability to help businesses better manage their energy costs and reduce system costs."[7] The application process for the Pilot Program launched on

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[5] The IESO released an updated annual demand forecast on October 16, 2024, as part of their 2025 Annual Planning Outlook, forecasting an increase in demand from 151 terawatt hours (TWh) in 2025 to 263 TWh in 2050. The news release can be found at: https://www.ieso.ca/Corporate-IESO/Media/News-Releases/2024/10/Electricity-Demand-in-Ontario-to-Grow-by-75-per-cent-by-2050.

[6] Customers with an average monthly maximum hourly demand greater than 1 MW and customers in select industries with an average monthly maximum hourly demand of 500kW-1MW can opt in to the ICI. Customers who opt in to the ICI pay their share of GA based on their contribution to the top five peak demand hours over a 12-month period. More information can be found at: https://www.ieso.ca/en/Sector-Participants/Settlements/Global-Adjustment-Class-A-Eligibility

[7] This quotation is from the November 2021 Mandate Letter to the OEB, which can be found at: https://www.oeb.ca/sites/default/files/Letter-from-the-Minister-of-Energy-2022-606.pdf.

October 6, 2022, with the final application deadline set for May 5, 2023. No applications were received by the deadline.

The OEB remained committed to exploring dynamic electricity pricing for Non-RPP Class B customers. In lieu of a Pilot Program or in-field testing, the OEB launched a research-driven and consultation-based approach to identify alternative opt-in price plans for Non-RPP Class B customers. The revised OEB's Dynamic Pricing Initiative included the following activities:

1. **Redesign of Dynamic Pricing Initiative:** The OEB developed a detailed design for the project involving a research-based approach complemented by industry engagement and stakeholder consultation. An external consultant, Guidehouse, was retained to assist with research and industry engagement.

2. **Development of alternative GA price plans:** Leveraging findings from the OEB's February 2019 Staff Research Paper[8] (2019 paper), the OEB developed eight alternative GA price plans based on economic efficiency and cost causation principles.

3. **Analysis of historical consumption data:** Advanced Metering Infrastructure (AMI) data representing over 50% of this customer group from 2021-2023 was analyzed to test the bill impacts of eight candidate price plans. Two price plans were selected based on providing the greatest net benefit to customers and the broader system without materially impacting non-adopters.

4. **Interviews with customers and consumer associations:** Guidehouse and the OEB interviewed 13 consumer associations and 16 Non-RPP Class B customers to gauge the appeal of the selected price plans, as well as decision-making factors and information needs required for potential price plan adoption.

5. **Consultations with industry stakeholders**: The OEB gathered feedback from LDCs, the IESO, consumer advocates and other industry stakeholders on price plan preferences, impacts on operations and implementation feasibility.

[8] The 2019 OEB Staff Paper can be found at: https://www.oeb.ca/sites/default/files/rpp-roadmap-staff-research-paper-20190228.pdf.

1.2 Who are Non-RPP Class B customers?

Non-RPP Class B customers represent approximately 50,000 electricity consumers in Ontario, with a maximum average monthly demand of 50 kilowatts (kW) to over 1,000 kW.[9] This is a diverse group that includes mid-size commercial and light industrial businesses, such as large retail stores, office buildings, schools, hospitals and small manufacturers. These customers have no regulated alternative price options available to them, except for those eligible to participate in the ICI.

Electricity commodity costs (consisting of wholesale market costs and GA) are collected differently from three groups of customers: Class A customers, RPP Class B customers, and Non-RPP Class B customers. This is outlined in Table 1 below.

Table 1: Classes of electricity customers in Ontario and how they pay electricity commodity costs.

Description			Commodity Prices	
Class A	General Service >1MW[10]		Wholesale market price[11]	GA paid via ICI
Class B	RPP	Residential General Service <50kW[12]	Selection between Tiered, TOU or ULO rate options	
	Non-RPP	**Everyone else[13]**	**Wholesale market price[11]**	**Class B GA rate**

Non-RPP Class B customers have heterogeneous load profiles since they are medium-to-large non-residential customers across a variety of sectors. While some are capable of shifting load in the short term by making operational changes, many are constrained by factors necessary to their bottom line, such as fulfilling timely orders, ensuring occupant comfort, and

[9] Using the 'General Service >= 50 kW' rate class as an approximation for Non-RPP Class B consumers, from 2021-2023, there were 49,570-52,279 customers. This information is from the "Electricity Reporting & Record Keeping Requirements (RRR): Section 2.1.2 Market Monitoring Information," which can be found at: https://www.oeb.ca/open-data/electricity-reporting-record-keeping-requirements-rrr-section-212-market-monitoring.

[10] Consumers in select industries with an average monthly maximum hourly demand of 500kW-1MW can also opt into Class A. For more detail, the *O. Reg. 429/04: Adjustments Under Section 25.33 of the Act* can be found at: https://www.ontario.ca/laws/regulation/040429.

[11] The HOEP is the wholesale market price today. It will be retired and replaced by the Day-Ahead Market Ontario Zonal Price plus the Load Forecast Deviation Adjustment under the anticipated implementation of the IESO's Market Renewal Program in May 2025.

[12] For more on RPP eligible, *O. Reg. 95/05: Class of Consumers and Determination of Rates* can be found at: https://www.ontario.ca/laws/regulation/050095.

[13] Typically consisting of consumers who are General Service >50kW

shift hours that accommodate employee satisfaction. In contrast with residential customers who commonly adjust loads, such as Heating, Ventilation and Air Conditioning (HVAC) systems, to trade comfort and convenience for cost savings, Non-RPP Class B customers are more likely to adopt longer-term structural responses such as making investments in energy efficient equipment. Typically, the equipment they buy is capital and energy intensive, and in place for a long time so strong price signals can facilitate investments in technology and efficient management of electricity usage.

1.3 What problem are we trying to solve?

The OEB's approach to dynamic pricing was predicated on its desire to enable customer choice and better align Non-RPP Class B customers' price signal with provincial costs.

Enable customer choice

The Government of Ontario has emphasized the importance of offering choice to electricity customers in the province.[14] Class B RPP customers have a choice in selecting the electricity price plan that suits their lifestyle or business: TOU, Tiered or ULO. Class A customers can opt into the ICI program, an initiative aimed at shifting large electricity consumers' consumption to off-peak hours. Non-RPP Class B customers have long advocated for additional price plans to support the unique nature of their business operations. The availability of an additional price plan could help these customers better manage energy costs by choosing a price plan that suits them and/or adjusting their electricity usage for bill savings.

Align customer prices with system costs

The current approach to recovering GA costs from Non-RPP Class B customers does not incentivize them to respond effectively to fluctuations in electricity demand throughout the day or communicate the most cost-effective time to consume electricity.

Today, Non-RPP Class B customers pay electricity commodity costs consisting of two parts:

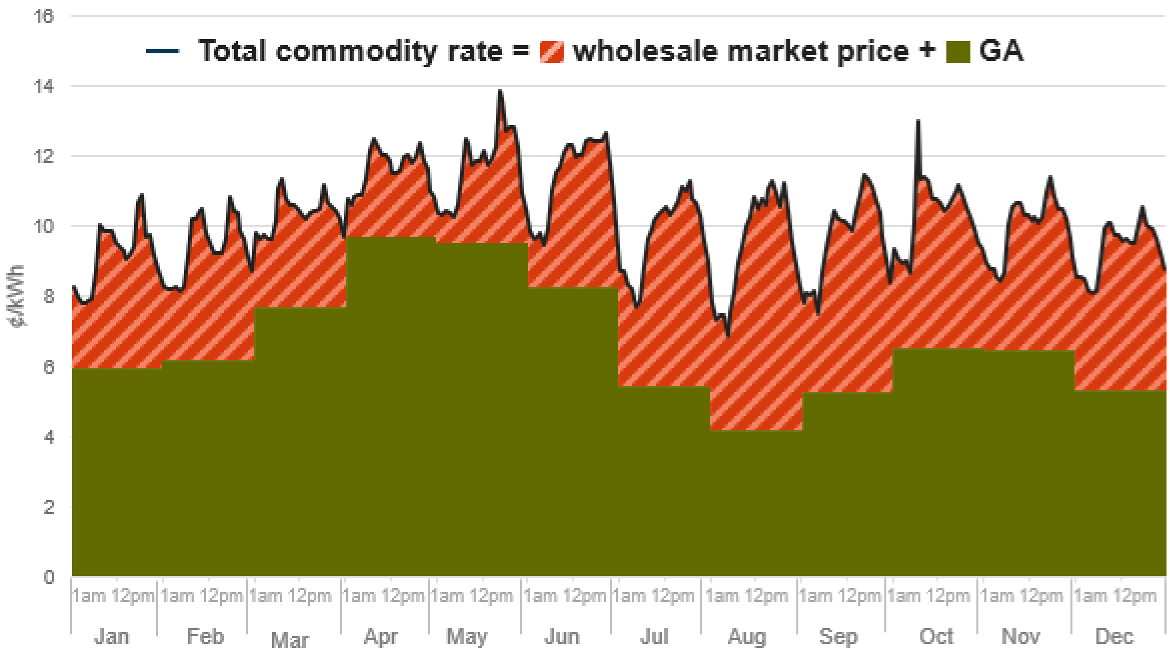
1. the wholesale market price,[15] and

[14] The 2022 Letter of Direction to the OEB refers to the government's vision for an energy sector and system that enhances customer choice. The letter can be found at: https://www.oeb.ca/sites/default/files/letter-of-direction-from-the-Minister-of-Energy-20221021.pdf.

[15] The HOEP is the wholesale market price today. The HOEP will be retired and replaced by the Day-Ahead Market Ontario Zonal Price plus the Load Forecast Deviation Adjustment under the anticipated implementation of IESO Market Renewal Program in May 2025.

2. GA.

Figure 1: Average weekday commodity rates by month for Non-RPP Class B customers 2021-2023.



Source: IESO Data Directory

GA is charged on a volumetric basis using the Class B GA rate published by the IESO each month. Volumetric means that the rate is based on the volume of electricity consumed ($/kWh). The Class B GA rate is based on total monthly electricity consumption, regardless of when that consumption occurs. Since GA is inversely related to average monthly wholesale market prices, the monthly GA rate is highest during the shoulder seasons (i.e., fall and spring) when average wholesale market prices are low, and lowest during peak months (i.e., summer and winter) when average monthly wholesale market prices are high. This is illustrated in Figure 1. Thus, the total commodity rate (the sum of the wholesale market prices and the Class B GA rate) does not reflect when electricity costs more or less to produce. Therefore, the status quo GA rate is not cost reflective and does not provide Non-RPP Class B customers with efficient price signals. A recent assessment of compensation mechanisms for DERs in Ontario noted this inefficiency, stating “For non-Regulated Pricing Plan (non-RPP) Class B customers, time-invariant volumetric recovery of GA costs is inefficient and should be replaced with a mechanism that allocates costs based on their drivers."[16]

According to the cost-causation principle, those responsible for incurring a cost should bear that cost. In other words, electricity consumers should pay for electricity in proportion to their usage of the system and share of its costs. By providing options that are more reflective of system costs, customers are incentivized to make investment decisions that promote affordability through economic efficiency and participate in demand management and electricity conservation to keep system costs down in the long run. This supports efficient outcomes for participating customers and the wider system.

1.4 Program Objectives

To achieve the initiative's broader policy goals of enabling customer choice and aligning customer prices with system costs, the OEB identified three objectives for designing alternative opt-in price plans for collecting GA from Non-RPP Class B customers.

Objective #1: Cost reflectiveness
By adjusting prices to be more reflective of system costs, we can align the electricity prices that customers pay with the impact their usage has on the overall electricity system, encouraging more economically efficient capital planning by medium- and large-sized businesses. Economically efficient use of electricity system assets promotes affordability for all electricity consumers by encouraging more electricity usage during times of abundant electricity supply, and encouraging less electricity usage during times when supply conditions tighten and costs rise. The more cost-reflective the pricing mechanism is, the more economically efficient system outcomes are in the long term.

Objective #2: Minimize short-term disruption
Alternative opt-in price plans should not cause significant disruptive bill changes for non-participants in the short term (within five years of the price plan being made available). Minimizing short-term disruption for Non-RPP Class B customers that do not opt into an alternative GA price plan is important to avoid unexpected challenges owing to the introduction of a new price plan.

Objective #3: Implementation feasibility

[16] From the 2025 Brattle report, *Assessment of Ontario's DER Compensation Mechanisms and Recommendations,* which can be found at: https://www.oeb.ca/sites/default/files/2025-AUG__Assessment-of-Ontario-DER.pdf

Implementing alternative GA price plans at the provincial level should be feasible. The selection process must consider potential resource constraints and implementation costs, and ensure there is sufficient time for testing system changes.

1.5 Recommendations

To enable customer choice and better align electricity pricing with costs, the OEB recommends taking steps to implement the Non-RPP TOU price plan for Non-RPP Class B customers in a phased approach. Next steps would include an exploration of how to resolve variance challenges as well as identifying in greater detail the steps needed to be taken by the Ministry of Energy and Electrification, IESO, OEB and LDCs.

The AMI analysis, customer interviews and stakeholder engagement suggest that Non-RPP TOU is likely to achieve higher adoption rates and faster implementation than RTP while still reducing peak demand. Customers and other stakeholders cited a general preference for this plan's simplified and predictable pricing structure. Although the Non-RPP TOU plan is less cost reflective than the RTP, its faster implementation also offers LDCs a more straightforward approach to providing this option to customers. Stakeholders alluded to the possibility of its simpler implementation given familiarity with TOU plans for LDCs.

While RTP is flexible and offers higher potential long-term system benefits, there are concerns regarding customer communication, LDC billing and settlement upgrades, and the implementation of automated day-ahead price setting. The OEB will reassess RTP for future implementation if these issues can be resolved.

Variance is likely to be more difficult to control for any price plan that recovers only GA costs compared to a price plan that recovers all commodity costs (like the RPP). This means that there is a risk of accruing variance which could cause rate shock if an alternative GA price plan is implemented. To mitigate against such, the OEB recommends considering adjusting the price plans to recover all commodity costs (wholesale market costs and GA) as opposed to GA only. Further stakeholder consultation is recommended to assess this approach.

Implementing either price plan would require additional activities such as determining eligibility, designing settlement factors, making changes to regulations, and updating the GA settlement process. Based on input from LDCs and the IESO, the OEB advises that the Non-RPP TOU price plan be made available to customers at a timeline that accommodates resource constraints and reduces regulatory burden relating to ongoing initiatives.

This report discusses the various activities undertaken as part of this initiative. Section 2 outlines the price plan design and development, including a description of the two selected alternative GA price plans. Sections 3 and 4 describe the feedback received and findings from customer interviews and stakeholder engagement with LDCs, the IESO, consumer advocates and others. The two plans are then assessed against the three program objectives in Section 5, before highlighting key implementation considerations for Non-RPP TOU in Section 6.

2 PRICE PLAN DEVELOPMENT AND SELECTION

This section outlines:

- the cost-reflective basis upon which all alternative GA price plans were derived (**Section 2.1**),
- the eight alternative GA price plans examined (**Section 2.2**),
- the selection of price plans via customer bill analysis (**Section 2.3**); and
- the two alternative GA price plans chosen for further analysis and stakeholder engagement (**Section 2.4**).

2.1 Cost-reflective basis of alternative GA price plans

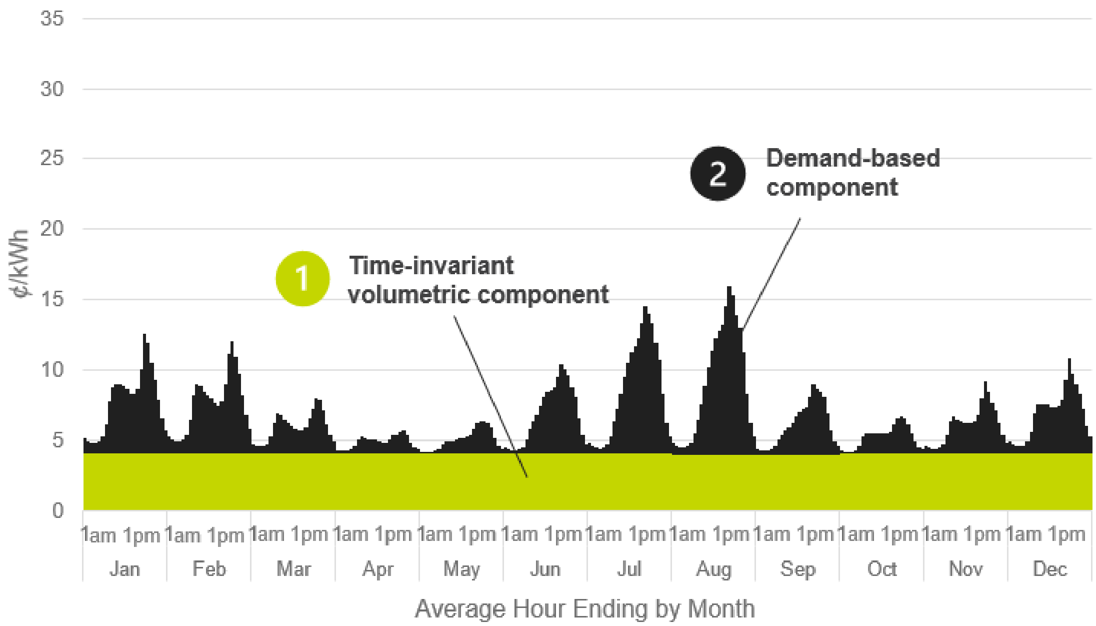
The cost-reflective basis of all alternative GA price plans considered is the Demand-Based Hourly Price (DBHP), which is a function of provincial demand developed for the recovery of the GA. The DBHP is cost reflective because provincial demand patterns are an important driver of total costs in the GA. This is because revenue collected by the GA covers many of the costs of Ontario's existing supply of power, supply that was procured to meet forecast patterns of demand.

The DBHP consists of two components:

1. A **time-invariant volumetric component** to recover fixed costs based on total energy consumed.
2. a **demand-based component** to recover variable costs based on consumer contribution to periods of higher provincial energy demand.

These components can be seen in Figure 2 below.

Figure 2: Average Weekday DBHP by Month (2021-2023).



The demand-based component of the DBHP was developed from the demand-shaped prototype described in the 2019 paper.[17] The demand-shaped prototype incentivizes demand shifting (avoiding capacity costs incurred) while maximizing consumer benefit (the value of electricity to consumers) by concentrating dollars to periods of high provincial electricity demand. This component is designed to recover variable system costs, costs incurred to serve peak electrical loads at the bulk system level. The mathematical definition of the demand-shaped prototype is set out in Appendix A: Development of the DBHP of this report.

The time-invariant volumetric component of the DBHP allocates GA costs based on total electricity consumption, independent of when it occurs. This is meant to recover fixed system costs, costs that are incurred independent of when electricity is consumed. One important difference between this component of the DBHP and the status quo Class B GA rate is that this component does not depend on the average wholesale market price in each month. Therefore, the inverse relationship described in Section 1.3 does not apply to the DBHP.

[17] The 2019 OEB Staff Paper can be found at: https://www.oeb.ca/sites/default/files/rpp-roadmap-staff-research-paper-20190228.pdf.

Both components together form the DBHP, a more cost-reflective rate that allocates fixed system costs according to total electricity consumption and variable system costs according to electricity consumption in each hour. Further DBHP details and supporting calculations can be found in Appendix A: Development of the DBHP of this report.

2.2 Alternative GA price plans considered

The OEB designed eight candidate price plans based on the DBHP. Each of the candidate price plans considered are one of three rate structures:

1. RTP
2. TOU
3. TOU with Critical Peak Pricing adder (CPP)

For RTP price plans, the price in each hour is based on the DBHP in that hour, with the difference being that the RTP is based on a forecast and the DBHP is calculated based on historical values. The RTP rate structure was considered because it is the closest approximation of the DBHP and therefore considered the most cost reflective.

For TOU price plans, the price in each period is based on the average demand-based component of the DBHP during that period, or a variation thereof. Price periods are based on time of day and day of week. The TOU rate structure was considered because it provides greater price certainty, while still reflecting average intra-daily variations in price, and is familiar to customers.

CPP price plans are TOU price plans with peak pricing “events” throughout the year where prices are elevated for a specified period when demand is forecasted to be high. This rate structure was considered because CPP is one of the standard rate structures considered in professional literature regarding dynamic pricing, and CPP pricing pilots (including the 2017 – 2019 RPP pricing pilots)[18] have demonstrated that (mostly residential) customers in Ontario exposed to these prices will on average provide some short-term beneficial price response. This means that these customers achieved savings compared to their baseline price plan and benefitted the bulk electrical system (generation and transmission) due to their load shifting.

Detailed descriptions of each of the eight candidate price plans can be found in Appendix B of this report.

[18] More information on the RPP pricing pilots and RPP Roadmap can be found at: https://www.oeb.ca/industry/policy-initiatives-and-consultations/rpp-roadmap.

2.3 Alternative GA price plan selection

The OEB procured an external consultant, Guidehouse, to assess the potential individual customer bill impacts of the eight candidate price plans using a set of anonymized individual customer data from four LDCs. This dataset includes anonymized hourly consumption data for more than half of the Non-RPP Class B customers (over 39,000 customers) in the province from 2021-2023. The purpose of this analysis was to use estimated individual bill impacts to develop an initial estimate of likely adoption and, consequently, estimate the potential impact on the unit cost of energy for non-adopters.

The estimate of likely adoption and potential impact for non-adopters allowed Guidehouse and the OEB to evaluate the eight candidate price plans against the program objectives to identify the two price plans for further consideration. All eight candidate price plans were shown to have minimal short-term disruption for customers who do not adopt. Guidehouse and the OEB determined that it would be most appropriate to move forward with the most cost-reflective price plan from the RTP price structure group and the most cost-reflective price plan from the TOU price structure group. The CPP price structure was eliminated from consideration because CPP is less cost-reflective than RTP plans without providing the same simplicity and predictability to customers as TOU price plans. In addition, Guidehouse identified that the perceived customer risk of a CPP pricing element may result in substantially lower adoption than TOU. For more in-depth information about the methods, results and rationale of price plan selection, please see Appendix C: AMI Analysis.

The most cost-reflective price plan of each chosen structure, RTP and TOU are the Non-RPP TOU and the RTP detailed in Section 2.4. An evaluation of each with respect to program objectives can be found in Section 5.

2.4 Proposed GA Price Plans

Of the eight candidate plans, the two most cost-reflective price plans were selected for further exploration. They were the Non-RPP TOU and RTP.

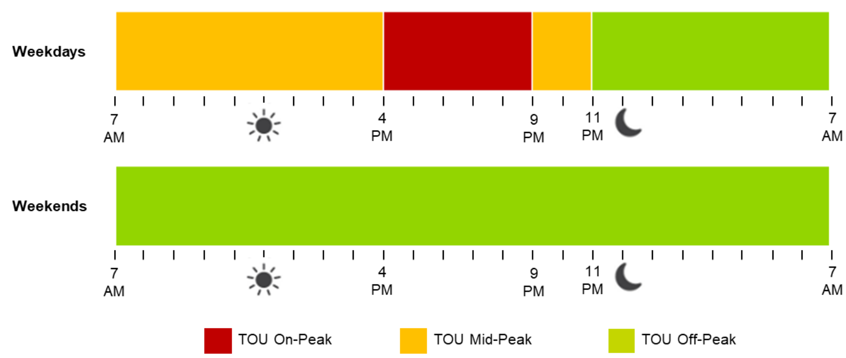
These price plans have been designed to recover the GA from Non-RPP Class B customers on an opt-in basis. Customers who opt in would still pay wholesale market prices as they do today.

2.4.1 Non-RPP TOU

The Non-RPP TOU plan offers a defined GA price that varies by time of day. Under Non-RPP TOU, customers would pay different prices for three time periods (see Figure 3):

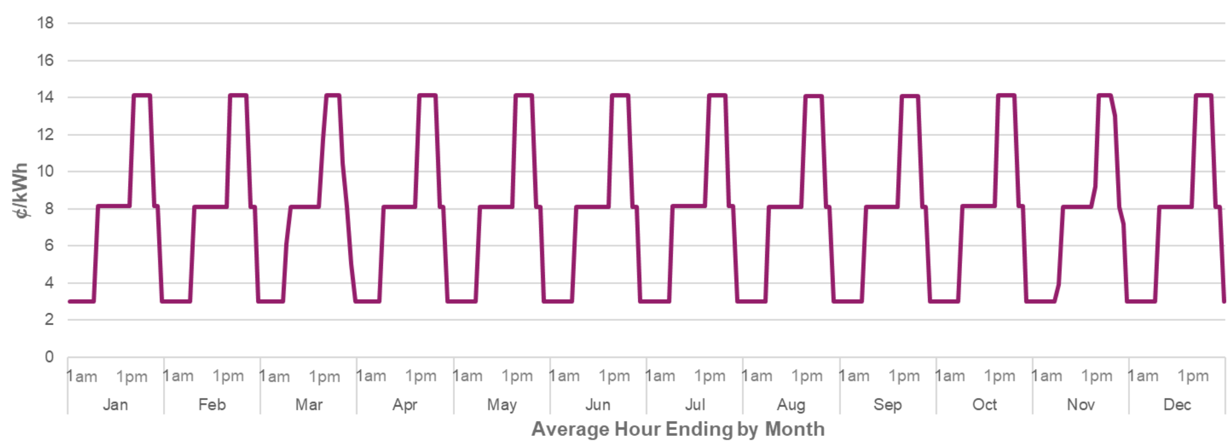
- off-peak prices at the lowest rate between 11 p.m. and 7 a.m. on weekdays and all hours of weekends,
- mid-peak prices at a higher rate between 7 a.m. and 4 p.m. on weekdays, and
- peak pricing at the highest rate from 4 p.m. to 9 p.m. on weekdays.

Figure 3. Time Periods Aligning with On-Peak, Mid-Peak and Off-Peak Rates for Non-RPP TOU.



The Non-RPP TOU time periods are based on previous load studies and do not vary by season.[19] Seasonal price signals are still communicated to customers via wholesale market prices.

Figure 4: Average weekday Non-RPP TOU price by month for an example historical year.



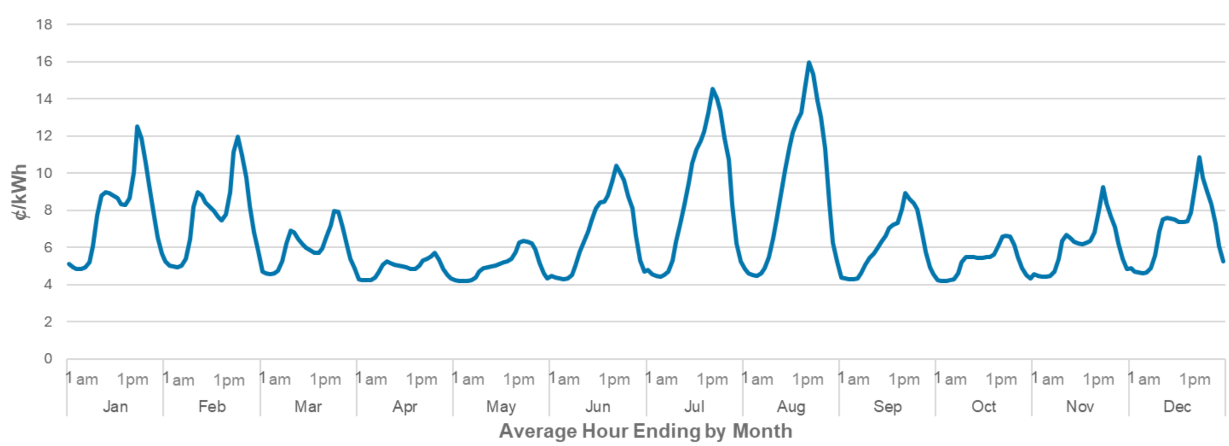
[19] Time periods are based on the *Design of an Optional Enhanced Time-of-Use Price* model that can be found at: https://www.oeb.ca/sites/default/files/Report-Design-of-an-Optional-Enhanced-Time-of-Use-Price-20220331.pdf.

The Non-RPP TOU price design is distinguished from the RTP by simplicity and predictability. In alignment with the principle of cost causation, customers pay higher prices on average for periods of the day with higher demand, such as weekday evenings. The average weekday Non-RPP TOU prices for an example historical year are shown in Figure 4. As the price plan offers fixed prices throughout the year, Non-RPP TOU provides predictability and certainty to customers' bills, which in turn enables customers with programmable electricity loads to benefit and manage energy consumption more efficiently, relative to the status quo.

2.4.2 RTP

The RTP plan is the more dynamic and cost-reflective option. RTP provides an hourly GA price correlated with Ontario electricity demand that would be set daily based on day-ahead demand forecasts. When electricity demand is high, GA prices will be higher; conversely, when demand is low, prices will be lower. Unlike the Non-RPP TOU, RTP fluctuates every hour, making electricity bills more sensitive to seasonal and daily demand variations. The highest electricity prices are likely to be on the hottest and coldest weekdays. The average weekday RTP prices for an example historical year are shown below in Figure 5.

Figure 5. Average weekday RTP price by month for an example historical year.



Customers with flexible loads (e.g., customers whose loads are not determined by HVAC) may benefit from this option. RTP may be a less attractive option to customers that prioritize certainty and predictability and whose electrical loads are higher during seasonal peak demand periods.

3 CUSTOMER INTERVIEWS

This section outlines:

- The methodology and process of the customer interviews (**Section 3.1**); and
- The customer interview results (**Section 3.2**).

The OEB and Guidehouse carried out two phases of interviews, the first with consumer association staff and the second with Non-RPP Class B customers. Both phases are referred to broadly as 'customer interviews' in this report. These activities were carried out independently from other stakeholder engagement activities that are detailed in Section 4. The objectives of the customer interviews were to:

1. Understand Non-RPP Class B customer acceptance, preference and potential adoption of the two alternative GA price plans.
2. Identify the motivations, adaptability and decision-making processes of Non-RPP Class B customers for adopting an alternative GA price plan (e.g., electricity consumption trends, load shifting capabilities, and operational planning and management processes).
3. Determine the level of information and types of communication tools preferred by customers to facilitate alternative GA price plan selection and potential adoption.

While these interviews provided valuable insights into the drivers of decision-making and perspectives of Non-RPP Class B customers, the findings of this exercise apply to the customers interviewed and may not be applicable to all customers in this large and diverse customer group.

3.1 Methodology and process

Potential interview participants for the two phases of interviews were identified based on their expressed interest in the initiative, alignment with sectoral classifications, prior engagement with Guidehouse or the OEB, and/or the results of the AMI analysis. The OEB and Guidehouse targeted 10 sectors or types of premises for customer interviews to account for the diversity of this group, including agriculture, education, EV fleet operators, healthcare, hospitality, manufacturing, multi-residential housing, office and retail, water and wastewater management, and other commercial and utilities.

Table 2. Number of consumer associations and customers interviewed by sectoral classification.

Sector Classification of Customer Accounts	Phase 1		Phase 2
	Consumer Associations	Customers	Customers
Agriculture	3	1	1
Education	1	4[20]	1[19]
Healthcare	1	1	1[19]
Hospitality	1		
Manufacturing	2	1	
Multi-residential Housing	2	3	2[19]
Office & Retail	2	1	1[19]
Water/Wastewater Treatment			1[19]
Other Commercial and Utilities	1		2
Total	**13**	**11**	**6**

Between March 4 and September 4, 2024, 22 customer interviews were conducted across two phases. In total, 13 consumer associations and 16 Non-RPP Class B customers participated actively in these interviews. The second phase of interviews included an individualized bill analysis component, during which the OEB and Guidehouse presented six customer interview participants with their bill impact results from the AMI Analysis to better understand alternative GA price plan acceptance and potential adoption.

3.2 Customer interview results

Price plan preference

Customer interviews revealed a diversity of perspectives regarding customer acceptance, preference and potential adoption of one or both price plans. Interview participants that favoured stability and certainty in electricity pricing preferred Non-RPP TOU. Those with seasonal operations or greater ability to shift their electricity loads – and save more compared to their status quo bills – were more amenable to RTP.

The level of electricity cost savings needed to motivate a price plan switch among interviewed participants varied greatly. In general, interview

[20] There is some overlap of customers for these values. One customer was present in both phases of interviews (i.e., in education). Another interviewed customer shared information for four types of premises/accounts and was therefore counted across four sectors in Phase 2 interviews: office/retail, healthcare, multi-residential housing and water/wastewater treatment. These two customers were counted only once in the total number of direct customers interviewed (i.e., 16 customers).

participants highlighted the need for electricity cost savings to exceed the costs of switching, including the costs of assessing any offered price plan against the status quo. For organizations considering RTP, any additional costs needed to implement price monitoring and energy management functions would be considered a cost of switching.

While several interview participants saw potential savings under either alternative GA price plan based on historical consumption patterns, they viewed these potential savings as insufficient to motivate a price plan switch in the short term. Some interview participants indicated a potential willingness to switch in the longer term. For some interview participants, the availability of one or both price plans may encourage new technology investments or facility upgrades to reduce their overall electricity load. Other customers preferred to observe adoption rates and experiences of other Non-RPP Class B customers before considering an alternative GA price plan.

Customer motivations and decision-making

A high proportion of interview participants highlighted the importance of a stable and predictable price for electricity. As a result, many of these customers pointed to Non-RPP TOU as being favourable to operational planning and financial management processes, such as annual budgeting, project controls and governance, and investment decisions. Several interview participants mentioned the need to present a clear business case to their senior management, including calculations based on historic electricity consumption patterns, to switch to an alternative GA price plan.

Consumer association groups also suggested that most Non-RPP Class B customers do not have dedicated energy managers to support the deployment of energy efficiency measures, such as monitoring and tracking of electricity pricing and electricity load shifting activities. In turn, such limited energy management resources may make the adoption of a more dynamic price plan such as RTP difficult for some customers.

Several interview participants identified barriers to deploying demand response measures to reduce their electricity costs under one or both alternative GA price plans. This was particularly the case for customers that were mandated to meet specific service standards, such as healthcare organizations and multi-residential housing. Businesses whose operations aligned with customer demand (e.g., hospitality, office/retail) or rely heavily on set staffing schedules (e.g., manufacturing) also highlighted challenges in shifting electricity loads. At the same time, some organizations spoke to their existing strategies and solutions, such as pre-cooling buildings to avoid running HVAC during peak demand times.

Information and communication tools for price plan education

Customers underscored the importance of information and communication tools to motivate switching to a potential alternative GA price plan. Every interviewed customer mentioned that a price plan switch would require a detailed electricity bill impact analysis informed by historical consumption patterns as well as a consideration of financial risk and price certainty.

Interviewed customers welcomed the idea of a simple tool that would enable individualized electricity bill calculations based on their electricity consumption data for all available price plans. They said an additional function to run scenario analyses would also be beneficial. Consumer associations also suggested the development and dissemination of case studies and testimonials as useful communication tools. For information regarding existing or new price plans, interview participants confirmed their reliance on their LDCs in navigating price plan decisions.

4 STAKEHOLDER ENGAGEMENT: WHAT WE HEARD

This section outlines:

- What we heard during the Stakeholder Consultation session held on September 9th, 2024, and through written feedback submitted following the session (**Section 4.1**);
- What we heard from engagement with LDCs (**Section 4.2**); and
- What we heard from engagement with the IESO (**Section 4.3**).

The OEB recognizes the significant contributions of stakeholders in providing insights and shaping sound policy decisions that enable Ontario's energy advantage, facilitate economic growth, protect customers and deliver affordable energy to Ontarians. The OEB is committed to engaging stakeholders in a meaningful way to draw on diverse perspectives, build trust and enhance transparency.

As part of this initiative, the OEB solicited feedback from stakeholders on price designs and implementation considerations for the two alternative GA price plans. This section is structured by the following three stakeholder engagement activities:

1. A consultation with broad industry stakeholders (**Section 4.1**);
2. Discussions with LDCs via the Electricity Distribution Association (EDA), Cornerstone Hydro Electric Concepts (CHEC) and Toronto Hydro-Electric System Limited[21] ('Toronto Hydro') (**Section 4.2**); and
3. Technical discussions with IESO divisions (**Section 4.3**).

Each engagement activity was designed to elicit specific information and highlight stakeholder perspectives pertaining to the alternative GA price plans identified for Non-RPP Class B customers.

4.1 Stakeholder Consultation

On September 9, 2024, the OEB held a stakeholder meeting to provide information on the design and development of the two alternative opt-in price plans outlined in Section 2. This meeting was intended to build on previous engagements with customers, LDCs and the IESO, and facilitate feedback from the broader industry on the two price plan designs and implementation considerations. Over a hundred participants representing LDCs, industry and

[21] A separate discussion was convened with Toronto Hydro as it is not a member of the EDA or CHEC.

consumer associations, private companies and other interest groups attended the session.

The OEB also invited written feedback from stakeholders on the proposed price plans. In total, 14 stakeholders submitted written comments in October 2024. Key highlights from written stakeholder feedback are presented in this sub-section as well as the LDC Engagement sub-section. A summary of the OEB's responses to additional questions and issues raised by stakeholders are provided in Appendix G: Summary of Stakeholder Comments and OEB Responses.

Price design and plan preference

In general, most stakeholders were supportive of the initiative to offer alternative opt-in price plans to Non-RPP Class B customers. Some stakeholders stressed the importance of fair and equitable rates that do not give undue preference to any one rate class. Several stakeholders elaborated on the ultimate purpose of the price plan development (i.e., to provide one or more cost-reflective options) and suggested modifications or alternatives to the price plan designs to serve other objectives. These other objectives included providing additional bill savings beyond what is cost reflective, encouraging behavioural change via higher price differentials, and establishing specific prices or rate attributes that incentivize the adoption of specific technologies.

Stakeholders did not express unanimous support for either alternative GA price plan, but most stakeholders suggested that Non-RPP TOU would appeal more to Non-RPP Class B customers. Support for Non-RPP TOU stemmed from the predictability and certainty of electricity pricing it offered, the potential savings for some Non-RPP Class B customers, increased potential customer uptake and relatively fewer perceived implementation complexities. Some customers expressed interest in incorporating seasonal variation or higher on-peak/off-peak price differences for Non-RPP TOU to improve behavioural response, demand side management efforts and efficient consumption.

Among those that did not prefer Non-RPP TOU, there was a range of views. Some preferred the RTP design and structure because of its cost reflectiveness and economic efficiency. One stakeholder suggested that RTP could support meaningful consumer behavioural changes such as enabling behind-the-meter solutions. Two stakeholders suggested that the OEB reconsider the CPP price structure, citing its potential to reduce peak demand. Some stakeholders expressed no preference between the two plans, with one encouraging the OEB to consider the preferred alternative GA price plan for distributors and customers.

Implementation considerations

Stakeholders highlighted the additional costs that LDCs would incur for the implementation of one or both alternative GA price plans, particularly for billing system changes (see Section 4.2 for more detail). Several stakeholders believed that implementation issues and associated costs required further study, with some suggesting more consultation after a decision is made on the price plan or price plans to be implemented. Two stakeholders pointed out that prior familiarity with TOU plans may lend to simpler implementation and administration of Non-RPP TOU.

Price plan communication to Non-RPP Class B customers

Most stakeholders urged the OEB to develop information materials and communication tools to support customer understanding and potential price plan adoption. These tools and information requests included:

- a comparative analysis tool or bill calculator to (1) assess a customer's load profile across time of day and season and (2) determine estimated bill impacts for each price plan available based on historical data.
- insights on or communication of GA price forecasts from the OEB or IESO, including price fluctuations.
- a general description of how GA is determined and the GA pricing options.
- additional content on the alternative opt-in GA price plan(s) that outlines design and key attributes.
- a document with answers to frequently asked questions.

A report on the uptake of price plans provincewide was also requested.

One stakeholder emphasized that LDCs may be able to advise customers generally on any newly introduced alternative GA price plan(s) but providing individualized recommendations may be difficult. It was suggested that an

OEB-led bill calculator[22] and other communication materials would support consistent messaging on any alternative GA price plan(s).

4.2 LDC Engagement

The OEB has engaged LDCs throughout this initiative and has received feedback from several individual LDCs as well as LDC associations. This feedback focused on the design of the alternative GA price plans as well as preliminary discussions on the potential operational impacts of implementation. LDC feedback has been categorized into six themes and summarized below.

Price plan preference

Most LDCs noted that Non-RPP TOU would be simpler to implement than RTP. Implementing RTP would likely demand more time and effort due to the extensive changes needed in billing systems and its impact on the settlements with the IESO. Additionally, LDCs suggested that the familiarity and predictability of the Non-RPP TOU plan might be more attractive to their Non-RPP Class B customers.

Timeline for rollout

LDCs expressed concern about the timeline for implementing one or both alternative GA price plans, citing resource constraints due to other changes in the sector. If implemented in the near term, the proposed price plans would be introduced during a period of significant sector changes, including the Market Renewal Program in 2025, the new Electric Vehicle Charger Discount Electricity Rate in 2026 and synchronization of net metering with the Meter Data Management/Repository.

Concerns about the timing of implementation highlight the need to consider finite LDC resources amidst ongoing sector changes and provide vendors with sufficient lead time to update billing systems accordingly. Staggering the implementation schedule may be important as many LDCs have a limited internal group to implement these changes. Some stakeholders suggested providing a lead time of 9-18 months and considering a staggered or two-stage rollout (e.g., an earlier date for some LDCs).

[22] Note that the RPP Bill Calculator (available: https://www.oeb.ca/consumer-information-and-protection/bill-calculator) does not use customer specific consumption information which would not be sufficient for Non-RPP Class B customers since their electricity consumption patterns are diverse and can differ significantly from one another. Customer specific consumption data would likely be required for a tool to provide relevant price plan impact information to this group of customers.

Eligibility and switching

The eligibility criteria will need to be clearly defined for any alternative GA price plan, particularly related to the eligibility of Class A customers. Overall, LDCs sought clarifications about whether the plan(s) would be made available to:

- all Non-RPP Class B customers,
- Class A-eligible customers that choose to remain as Class B,
- large Non-RPP Class B customers that are eligible for RPP prices (e.g., farm, bulk residential),
- customers on retailer contracts, and
- residential and small commercial customers eligible for RPP prices but who opted out for spot market pricing.

One stakeholder suggested that customers on retailer contracts be ineligible for the alternative GA price plan(s) because of technical limitations to metering and billing configurations while small-scale customers eligible for RPP that opted out for market pricing could be eligible.

The minimum timeframe commitment to stay on an alternative GA price plan will also need to be defined prior to implementation. One LDC suggested that the frequency of rate plan switching should match RPP practices and not interfere with annual customer rate class reclassification reviews. Some LDCs expressed concern about the implications of customers switching in and out of price plans within a one-year timeframe. LDCs expressed concerns about customers switching to “game the system” so that a customer would be on one price plan when those prices are low and switch to another when lower prices are available. LDCs also highlighted that comprehensive switching rules that include frequent customer status validations could be administratively burdensome on their operations, potentially more so than other areas of implementation.

Administration costs

LDCs pointed out that implementing the alternative GA price plan(s) may be costly and administratively burdensome to their operations. LDC billing systems might require a web-based interface to help customers compare pricing options and choose their preferred plan, similar to what was done for RPP customers. Setting up new sub-rate classes, updating billing systems, training staff, maintaining ongoing rates and communicating with customers about available choices could increase the administrative burden.

LDCs cited the following activities and changes as the cause of potentially significant administrative burden and costs:

- upgrading and reviewing billing systems including developing accounting guides and codes,
- vendor contracts or additional work,
- metering configuration (for Non-RPP TOU),
- developing internal billing system co-ordination to account for system and infrastructure changes to accommodate any structure based on time of day rather than metered consumption,
- increased regulatory and financial efforts (e.g., load forecasting, rate design, billing determinants, settlements, variance accounts),
- additional administrative tasks such as customer rate validation,
- customer communication, and
- customer load profile tracking.

Customer communication

LDCs pointed out that they are typically responsible for educating their customers about available options, which could lead to a significant increase in customer service calls. One of the main challenges for LDCs in implementing new price plans is explaining the new options to their customers. If the plans are not clearly communicated, it can result in a high volume of customer service inquiries. Customers will also need access to their interval data to conduct their own analyses. As a result, LDCs suggested that streamlined OEB graphics and informational tools, such as a bill calculator similar to those provided for RPP price plans, would be beneficial.[23]

Potential uptake

Several LDCs noted that the costs of offering these choices must be weighed against implementation costs, especially if customer uptake is expected to be low. Some LDCs warned against repeating their experiences of implementing the ULO price plan for RPP customers and Green Button data, both of which they said were costly and had low customer uptake to date.

[23] Note that the RPP Bill Calculator (available: https://www.oeb.ca/consumer-information-and-protection/bill-calculator) does not use customer specific consumption information which would not be sufficient for Non-RPP Class B customers since their electricity consumption patterns are diverse and can differ significantly from one another. Customer specific consumption data would likely be required for a tool to provide relevant price plan impact information to this group of customers.

4.3 IESO Engagement

The OEB engaged the IESO from April to August 2024 to get feedback on the price plans under consideration and identify any technical barriers to updating GA settlement processes. While no material barriers were identified, important implementation considerations were discussed and are summarized below.

Variance

The IESO noted that there are no efficiency gains for creating multiple variance accounts because the funds must be managed separately. One variance account would need to be set up for each alternative GA price plan implemented.

GA Settlement

The current GA settlement process for Class B customers is outlined in Appendix E: Global Adjustment Settlement. In general, the IESO noted that the status quo Class B rate calculation is very complex and introducing an alternative GA price plan with its associated variance will add to this complexity. It would also impact the monthly settlement process of Class B GA between the LDCs and the IESO since the alternative GA price plans proposed vary by time of electricity consumption. Therefore, the IESO identified the need for a clear flow of information into the Class B GA settlement process if any alternative GA price plan were implemented.

From the IESO's perspective, there are no efficiency gains for implementing both plans concurrently. As with the variance accounts, implementing both price plans would double the effort of offering one alternative GA price plan.

Eligibility

Regarding eligibility, the IESO raised a question about customers in the IESO-administered markets ('market participants') as opposed to customers who buy electricity from their LDC. Non-RPP Class B market participants account for a small percentage of Non-RPP Class B customers. They consist of generation facilities, electricity storage facilities (ESF),[24] storage facilities that are not Class A or deemed ESF, and load facilities that are not Class A. Approximately half of them are generation facilities whose operations are dictated by dispatch instructions and schedules determined by the IESO. The IESO asked the OEB to consider the potential costs of including Non-RPP

[24] Section 5(1) of the *O. Reg. 429/04: Adjustments Under Section 25.33 of the Act* provides a definition of "electricity storage facility" and can be found at: https://www.ontario.ca/laws/regulation/040429.

Class B customers in the IESO-administered markets in the alternative GA price plan(s).

If market participants were to be eligible for an alternative GA price plan, the IESO indicated that it would need to establish a process for them to opt in. Given the recent implementation of ULO for RPP customers, LDCs have experience implementing new price plans for LDC-connected customers. Offering a regulated price plan to market participants has not been done and therefore has an increased risk of unforeseen challenges. Therefore, offering new price plans to market participants would likely be more challenging than offering to LDC-connected customers. The IESO acknowledged that offering alternatives to only LDC-connected customers raises equity issues in fair treatment for all Non-RPP Class B customers in the province.

Implementation Timelines

The IESO indicated that the implementation timeline for one or both alternative GA price plan(s) would be dependent on, but not limited to, the following factors:

1. Eligibility of market participants
2. Availability of IESO resources
3. Coincident timing with the Market Renewal Program
4. Any other Ministry initiatives

5 EVALUATION OF PRICE PLANS

In this section, the two proposed GA price plans are evaluated against the three program objectives defined in Section 1.4. They are evaluated against:

- Cost reflectiveness in **Section 5.1**,
- Minimizing short-term disruption in **Section 5.2**; and
- Feasible implementation in **Section 5.3**.

Figure 6 below summarizes the results of this evaluation with respect to the three objectives. An additional evaluation of the price plans with respect to rate design principles can be found in Appendix F: Evaluation of Proposed Price Plans Against Rate Design Principles.

Figure 6: Summary of the evaluation of the two proposed GA price plans.

	Non-RPP TOU	RTP
Cost Reflective	◐	●
Minimal Short-Term Disruption	●	●
Feasible Implementation	●	◐
While RTP is more cost reflective than the Non-RPP TOU option, RTP comes with additional implementation complexities. Both options minimize short-term disruption for non-adopters.		

5.1 Program objective #1: Cost reflectiveness

A cost-reflective rate aligns customer prices with the costs their use imposes on the electricity system. This encourages more efficient use of the electricity system by enabling customers to make decisions on when and how much electricity to consume if the value of electricity at a given hour exceeds the price at that hour. Since the price plans explored through this initiative are designed to recover GA, cost reflectiveness in this context means that these rates reflect the costs paid for by the GA. The GA covers the costs of building electricity generation infrastructure, maintaining and refurbishing existing generation resources and the delivery of conservation programs in Ontario. Those costs ensure there is enough electricity supply available today and in the future.

RTP is more cost reflective than Non-RPP TOU

The RTP is more cost reflective than the Non-RPP TOU because it more closely aligns with the DBHP. The Non-RPP TOU reflects intra-daily fluctuations in demand, and therefore price, but does not capture seasonal variability by design. Due to the flexible nature of the RTP, prices remain aligned with system costs as provincial load patterns evolve over time. The Non-RPP TOU, on the other hand, has set periods that must be updated periodically as provincial load patterns change to maintain its cost reflectiveness.

Long-term economic benefits

Cost-reflective price plans are not only considered on the basis of cost causality, but also for their ability to yield economic efficiency benefits through long-term price response. In the long term, both price plans will benefit all electricity customers and contribute to a more affordable electricity system through more economically efficient uses of grid assets, encouraging higher consumption when prices are low and lower consumption when prices are high.

Guidehouse performed calculations to quantify the possible long-term changes in electricity consumption including the reduction of peak demand from customers adopting each price plan. For RTP, Guidehouse estimated the long-term reduction in coincident peak demand to be 16 kW (15%) per adopter. For Non-RPP TOU, Guidehouse estimated the reduction to be 9 kW (7%) per adopter. The reduction is more significant for RTP because RTP exhibits a higher price during peak demand conditions. It is important to note these estimates provide a high-level approximation of long-term benefits of each price plan to the electricity system. The estimates are based on theoretical price elasticities and use historical data only. They do not account for future changes to demand and price as the province's energy transition continues to evolve.

5.2 Program objective #2: Minimize short-term disruption

The deployment of an alternative GA price plan will affect the bills of both customers who adopt the plan and those who do not. This is because any savings realized by adopters of the alternative GA price plan are to be offset by those who remain on the status quo Class B GA price plan.

To minimize short-term disruption, the proposed alternative GA price plans must avoid significant bill impacts for Non-RPP Class B customers who do enrol. To assess the short-term impact on the bills of non-adopters, assumptions must be made about the number of customers likely to switch to the new price plan in the short term and the savings these customers would realize.

The number of customers likely to switch are characterized as "likely adopters." Guidehouse assumed the decision to adopt was dependent on customer size, with small customers requiring a certain dollar amount of savings to make the switch, and large customers requiring a certain proportion of total bill savings to make the switch. Large customers (with annual bills of $150,000 or more) who save 5% or more, and small customers (with annual bills under $150,000) who save $1,000 or more, are assumed to be likely adopters of the alternative GA price plan. Likely adoption depends on customers being well-informed about the benefits of the alternative GA price plan.

Only customers that achieve savings without having to make any changes to their load profile ("structural winners") are assumed to switch price plans in the short term.

Non-RPP TOU

Assuming no change in their load profiles, about one-third of Non-RPP Class B customers[25] would likely see savings on their energy bills. These customers may have HVAC dependent loads, but their consumption during peak is lower than the provincial average. The remaining two-thirds would likely be better off on the status quo Class B GA rate. About **10%** of Non-RPP Class B customers would see enough savings to be considered likely adopters. If all likely adopters were to opt into this price plan, the GA portion of the bills of the remaining customers on the status quo GA rate would only increase by 0.3%. Their total bills would only increase by 0.2%.

RTP

Assuming no change in their load profiles, about one-third of Non-RPP Class B customers would likely see savings on their energy bill. These customers have flatter load shapes that typically do not follow the standard provincial HVAC load profile. The remaining two-thirds would likely be better off on the status quo Class B GA rate. These customers' loads vary more with weather (i.e., they are more dependent on HVAC). About **6%** of Non-RPP Class B customers would see enough savings to be considered likely adopters. If all likely adopters were to opt into this price plan, the GA portion of the bills of the remaining customers on the status quo Class B GA rate would only increase by 0.2%. Their total bills would only increase by 0.1%.

[25] Bill impacts are based on an analysis of hourly consumption data that includes more than half of Class B customers not enrolled in RPP price plans.

5.3 Program objective #3: Feasible implementation

To implement either of the proposed price plans, there would need to be changes to regulations to allow charging of a different GA rate than is set out in Ontario Regulation 429/04.

In addition, successful implementation of either price plan would require overcoming the following challenges:

1. **Understanding the Benefit.** Direct outreach with customer-specific savings estimates would be necessary to motivate adoption. Customers need bill impact estimates that they can trust and confirmation that the estimated savings would exceed the costs to switch.
2. **Supply Cost Alignment.** The average supply cost of adopters and non-adopters must be calculated before each price-setting period to minimize variances and ensure cost reflectiveness of the optional price plan.[26] To ensure both groups (adopters and non-adopters) pay their appropriate supply cost, the status quo Class B GA rate for Non-RPP Class B customers would need to be adjusted.
3. **Variance Control.** For either price plan, there is an increased risk of variance accrual since these price plans are designed to recover GA only. This is due to an increased sensitivity to the market price forecast. For more detail, see Appendix D: Price Setting, Variance and Cost Recovery. To mitigate against excess variance, the OEB recommends considering adjusting the price plans to recover all commodity costs (wholesale market costs and GA) as opposed to GA only.

Customers, LDCs, the IESO and other stakeholders provided important feedback and input to inform the identification of these implementation considerations and potential barriers. While these barriers exist for either price plan, **additional potential implementation barriers exist for RTP only:**

4. **Complexity Concerns.** RTP is more difficult for customers to comprehend because it changes hourly based on day-ahead demand predictions. Customers would need to understand that it does not necessarily require constant engagement to benefit them.
5. **Billing and Settlement System.** Billing and settlement system upgrades may be more significant for RTP. Updates to IESO

[26] The average supply cost is the cost consumers incur for their electricity consumption, depending on when and how much electricity they consume. This would be determined based on the DBHP and estimated hourly consumption.

settlement systems and LDC billing systems will be required to accommodate hourly prices communicated every 24 hours. Sufficient controls would need to be implemented to ensure safe data transfer.

6. **Day-Ahead Price-Setting.** For RTP, automated day-ahead price setting would be required to calculate prices based on near real-time conditions. This would require inter-agency dependencies and information flows between agencies and LDCs.

Due to this, if a decision was made to pursue the RTP price plan option, a minimum 12-month testing period would be prudent to investigate these potential barriers. This could be done by simulating the price setting, billing and GA settlement process between the OEB, the IESO and LDCs to better understand the workflows necessary and the accumulation of variance.

6 IMPLEMENTATION CONSIDERATIONS

The OEB's work to date has focused on price design. However, implementing the recommended Non-RPP TOU price plan would require significant enhancements to the GA settlements process, billing systems and other operational factors. The OEB identified six steps that would need to be completed as part of implementation activities. This section outlines these six steps and **Section 6.1** outlines the implementation risks identified.

LDCs, the IESO and other stakeholders stressed the need for adequate lead time for implementing an alternative GA rate for Non-RPP Class B customers. There are multiple other billing changes required such as net metering synchronization with the Meter Data Management/Repository[27] and changes to all current billing of wholesale market prices for the Market Renewal Program scheduled to go live in May 2025. Implementation timelines are likely to vary depending on whether the alternative price plan would be made available to Non-RPP Class B customers in the IESO-administered markets. Stakeholders estimated that it would take at least 9-18 months to implement an alternative GA price plan. Therefore, the OEB advises taking a phased approach to implementation, similar to the implementation of ULO for RPP customers.

Successful implementation requires collaboration across the sector to serve a customer class that has no other regulated option. This will involve co-ordinated efforts among stakeholders, including the Ministry of Energy and Electrification, the OEB, the IESO and LDCs. Policy consultations will be required to gather input, share progress and address challenges collectively. Specific roles will need to be determined at the outset of implementation along with a detailed implementation plan. A high-level overview of six key implementation steps is outlined below and the general roles can be found in Table 3.

Step 1: Assess Variance Risk. Careful consideration must be given to the treatment of variance since the price plans are designed to recover GA only as opposed to all commodity costs (like RPP). Variance amounts, either credit or debit, are likely to be higher per dollar collected. This is further described in Appendix D: Price Setting, Variance and Cost Recovery. As part of implementation activities, adjusting the price plan to collect all commodity

[27] Distributors will be required to integrate their systems with changes to the Meter Data Management/Repository to facilitate the collection and management of bi-directional smart metering data. This requirement is detailed in the *Collection, management and improved utilization of smart metering data for behind-the-meter distributed energy sources* regulation, which can be found at: https://ero.ontario.ca/notice/019-6521.

costs (wholesale market prices and GA) should be considered to mitigate the risk of accruing excess variance.

The timing and duration of the price-setting period will need to be determined. While an annual period that aligns with RPP price setting (November 1– October 31) would have efficiencies, the price-setting frequency must be determined to ensure variance credit or debit does not accumulate such that it would materially affect subsequent rates. Similar to the RPP, flexibility should be maintained to set prices if variance exceeds a predetermined threshold.

Step 2: Determine Eligibility and Settlement Factors. From a customer choice standpoint, broad eligibility for either price plan is encouraged. However, the OEB advises careful review of stakeholder feedback before finalizing eligibility rules, specifically with regards to IESO market participants. In addition, careful consideration must be given to opting in and opting out due to the variability between the proposed price plans and the status quo Class B GA rate. While the status quo GA rate changes monthly, the Non-RPP TOU option does not. A settlement factor, similar to the RPP settlement factor, could be used to ensure supply costs are properly paid for as customers opt out.

Step 3: Enable Regulatory Changes. Ontario Regulation 429/04 prescribes how the GA rate is to be calculated for Non-RPP Class B customers. As a result, to implement either of the proposed price plans, changes would need to be made to regulation(s) to allow charging of a different rate. If the Non-RPP TOU option is implemented, consideration should be given to enacting amendments that maintain flexibility to review the number of TOU periods and their defined hours at regular intervals, and update them if necessary, so that cost reflectiveness is maintained.

Step 4: Update GA Settlement Process. The IESO would need to:

1. Set up a variance account to track differences between forecasted and collected amounts for Non-RPP Class B customers, and
2. Update the GA settlement process with LDCs.

The average supply cost of adopters and non-adopters must be calculated before each price-setting period to minimize variances and ensure cost reflectiveness of the alternative price plan. Updates to the calculation of the status quo Class B rate will be required to account for GA collected via the alternative price plan. See Appendix D: Price Setting, Variance and Cost Recovery for more detail.

Step 5: Update LDC Billing. Each LDC would need to update its billing systems to offer the new price plan. This involves IT upgrades, including modifying billing software, enhancing customer web portals and adjusting data formats and granularity. LDCs would also need additional time to train staff on the new systems and develop LDC-specific informational aids to assist customers in understanding their bills under the new price plan(s) and ensure price plan awareness.

Step 6: Develop Informational Tools. Tools such as bill calculators[28] would be critical to help Non-RPP Class B customers make informed decisions. Ensuring that customers understand the potential benefits of an alternative price plan would be critical to enabling informed customer choice.

Addressing the implementation steps outlined above would be critical for the successful rollout of the Non-RPP TOU price plan. The OEB has outlined the preliminary actions of the actors involved for the rollout of Non-RPP TOU in Table 3. An alternative price plan cannot be implemented without making changes to regulations to allow for an alternative rate. Further detailed planning and collaboration are required to ensure a smooth transition.

Table 3. Initial implementation steps to rollout Non-RPP TOU by actor.

Actor	Expected Actions
Phase I: Implementation Planning	
OEB	1. **Address variance issue** and consider adjusting price plan(s). Engage stakeholders to assess this approach.
Ontario Government	2. **Determine eligibility** for optional price plan(s). 3. **Enact regulation changes** to allow GA to be charged according to the optional price plan(s).
Phase II: Implementation	
IESO	• Set up a **new variance account** to track the difference between forecasted and collected GA. • Update current **GA settlement processes**. • **Provide Reliability Outlook forecasts** required to set prices.
OEB	• **Set prices** for optional price plan(s). • Issue new **regulatory accounting guidance** for LDCs. • Develop **communications materials**.

[28] Note that the RPP Bill Calculator (available: https://www.oeb.ca/consumer-information-and-protection/bill-calculator) does not use customer specific consumption information which would not be sufficient for Non-RPP Class B customers since their electricity consumption patterns are diverse and can differ significantly from one another. Customer specific consumption data would likely be required for a tool to provide relevant price plan impact information to this group of customers.

LDCs	• Update current **GA settlement process** with the IESO for non-RPP Class B customers. • **Modify billing systems** to offer optional price plan(s). • Develop **LDC-specific communication** materials and **provide staff training** on new price plan(s).

6.1 Risks

Implementing any new price plan comes with associated risks. The risks considered through this initiative and the relevant mitigation steps are outlined in Table 4 below.

Table 4: Risks and mitigation steps.

Category	Risk	Mitigation Steps
Overall (applies to both price plans)	Low price plan awareness.	Provide informational tools to help customers make informed choices.
	Variance between forecast and actual GA costs will be more difficult to control compared to RPP.	Consider adjusting price plans to recover all commodity costs (like RPP).
Non-RPP TOU	TOU price structures can become less cost reflective over time if some or all their time periods are fixed (e.g., RPP) and not updated as provincial load patterns change.	Maintain flexibility to review the number of TOU periods and their defined hours at regular intervals and update if necessary, so that cost reflectiveness is maintained.
RTP	Unforeseen challenges and additional implementation barriers due to complex price plan structure.	Reassess price plan at a future stage with a minimum one-year testing period.

7 CONCLUSION

To enable customer choice and better align electricity pricing with costs, the OEB recommends taking steps to implement the Non-RPP TOU price plan for Non-RPP Class B customers in a phased approach. Next steps would include an exploration of how to resolve variance challenges as well as identifying in greater detail the steps needed to be taken by the Ministry of Energy and Electrification, IESO, OEB and LDCs.

To arrive at this recommendation, the OEB carried out five discrete sets of activities: developing alternative GA price plans based on cost causation principles, carrying out a customer bill impact analysis, interviewing customers and consumer associations, and holding targeted discussions with LDCs and the IESO before convening a broader stakeholder consultation.

As part of this approach, the OEB developed eight cost-reflective candidate price plans based on economic efficiency. Guidehouse completed an AMI analysis of these price plans using 2021-2023 consumption data accounting for over half of Non-RPP Class B customers in the province. This analysis enabled the OEB to focus on two price plans, selected on the basis of cost reflectiveness and customer acceptance. The two plans, Non-RPP TOU and RTP, were then discussed extensively with customers, LDCs, the IESO and other industry stakeholders. Insights from 22 customer interviews and numerous engagements with LDCs, and the IESO informed this work.

Overall, most stakeholders welcomed the initiative and the proposed opt-in nature of the price plan(s). Though there was no clear consensus between the two price plans, stakeholders agreed that the Non-RPP TOU may appeal to more customers and noted potential challenges for customer uptake and implementation of RTP in the near future. Stakeholders also raised concerns regarding implementation timelines, citing the number of ongoing regulatory changes and system updates required of LDCs.

The OEB has identified that the variance between forecasted and collected costs will be more difficult to control for GA price plans compared to RPP. This is because price setting would be more sensitive to volatile forecasts. To mitigate against excess variance, the OEB recommends considering adjusting the price plans to recover wholesale market costs and GA, like RPP, as opposed to GA only. Further stakeholder consultation is recommended to assess this approach.

Though RTP could deliver more long-term system benefits per adopter, it may be acceptable only if issues such as customer communication, LDC billing and settlement system needs and automating day-ahead price setting are resolved.

This has led to the recommendation to take steps to implement the Non-RPP TOU price plan. By introducing this plan, Non-RPP Class B customers would be offered a choice of electricity prices that more closely align with provincial demand and system costs. The price plan stands to offer short-term benefits to customers by enabling better management of energy costs relative to current approaches and may also support long-term benefits to the electricity system by reducing costs associated with capacity investments and promoting affordability for Ontarians.

APPENDIX A: DEVELOPMENT OF THE DBHP

Demand-shaped Prototype

In 2019, the OEB published a research paper that evaluated the economic efficiency of various rates for GA recovery from Class B customers.[29] A pricing model named the "demand-shaped price" was examined and is defined in Equation 1 below. In the research paper, pricing prototypes were considered for all Class B customers. This initiative only examines price plans for Non-RPP Class B customers. The equation below has been updated to reflect that.

Equation 1: Definition of the demand-shaped pricing prototype from the 2019 OEB Staff Research Paper.

$$P_{ia} = h_i + \frac{C_a}{D_a}\left(\frac{T_i}{d_a}\right)^w$$

Where:

- i is the hour
- a is the cost recovery period, the period over which forecasted costs are calculated to be recovered
- P_{ia} is the price in hour i in cost recovery period a
- h_i is the Hourly Ontario Energy Price in hour i
- C_a is the total Non-RPP Class B Global Adjustment cost in cost recovery period a
- D_a is the total Non-RPP Class B Ontario electricity demand in cost recovery period a
- T_i is the total Ontario electricity demand in hour i
- d_a is chosen to fully recover revenue from all Non-RPP Class B customers during cost recovery period a
- w is the power-law dependence of price on Ontario demand

In the research paper, two exponent values ($w = 2$ and $w = 6$) were examined. The demand-shaped prototype with an exponent of six ($w = 6$) was found to have the highest net benefits. This means that over time, this rate incentivizes demand shifting (avoiding capacity costs incurred) while maximizing customer benefit (the value of electricity to customers).

[29] The 2019 OEB Staff Paper can be found at: https://www.oeb.ca/sites/default/files/rpp-roadmap-staff-research-paper-20190228.pdf.

Demand-based Component

The demand-shaped prototype includes two terms, one for wholesale market prices and one for GA. The DBHP focuses on the GA term only. Therefore, the demand-based component of the DBHP is equal to the GA component (second term) of the demand-shaped prototype from the 2019 research paper with an exponent of eight. The exponent was determined through additional analysis done as part of the current initiative. The OEB tested additional exponent values using the same price elasticity model used in the 2019 research paper. Through this, an exponent of eight ($w = 8$) was determined to yield the highest net benefits before diminishing returns. The definition of the demand-based component of the DBHP can be seen below in Equation 2.

Equation 2: Definition of the demand-based component of the DBHP.

$$P_{ia} = \frac{C_a}{D_a}\left(\frac{T_i}{d_a}\right)^8$$

Where:

- i is the hour
- a is the cost recovery period, the period over which forecasted costs are calculated to be recovered
- P_{ia} is the price in hour i in cost recovery period a
- C_a is the total Non-RPP Class B Global Adjustment cost in cost recovery period a
- D_a is the total Non-RPP Class B Ontario electricity demand in cost recovery period a
- T_i is the total Ontario electricity demand in hour i
- d_a is chosen to fully recover revenue from all Non-RPP Class B customers during cost recovery period a

Time-invariant Component

Although the demand-shaped prototype was shown to yield the highest net benefits in the 2019 research paper, it may not be appropriate to recover all GA costs since the GA contains some costs that are independent of peak demand (i.e., fixed costs). Recovering all GA costs according to this rate design could over-allocate dollars to peak periods. Therefore, three other rate structures were considered to recover the fixed costs in the GA:

1. a fixed monthly charge ($),
2. a demand charge ($/kW), and
3. a time-invariant volumetric charge ($/kWh).

While a fixed monthly charge commensurate with the fixed cost each customer incurs on the system would be the most cost reflective, assigning a specific cost to each Non-RPP Class B customer is administratively burdensome, if at all possible. A uniform fixed monthly charge would be inappropriate for Non-RPP Class B customers given the considerable variation in customer size ranging from approximately 50 kW to over 1 MW. Fixed monthly charges based on income have been considered for residential customers in various jurisdictions. However, they are difficult to delineate for this group of customers, which includes businesses, hospitals, schools and other organizations. Therefore, a fixed monthly charge was eliminated.

A demand charge was eliminated from consideration because it assigns dollars based on a customer's demand (coincident or non-coincident with system peak demand, depending on design), which is not appropriate for collecting costs that are independent of demand.

Therefore, a time-invariant volumetric charge that allocates fixed costs based on total energy consumption (kWh) was deemed the most appropriate for this highly variable customer class. Under this rate structure, total energy usage is a proxy for share of fixed system costs imposed on the system.

Combining Each Component of the DBHP

Combining the time-invariant and demand-based components results in the DBHP which is shown in Equation 3 below.

Equation 3: Definition of the DBHP.

$$P_{ia} = b_a + \frac{C_a}{D_a}\left(\frac{T_i}{d_a}\right)^8$$

Where:

- i is the hour
- a is the cost recovery period, the period over which forecasted costs are calculated to be recovered
- P_{ia} is the price in hour i in cost recovery period a
- b_a is the time-invariant component in cost recovery period a
- C_a is the total Non-RPP Class B Global Adjustment cost in cost recovery period a
- D_a is the total Non-RPP Class B Ontario electricity demand in cost recovery period a
- T_i is the total Ontario electricity demand in hour i

- d_a is chosen to fully recover revenue from all Non-RPP Class B customers during cost recovery period a

To determine how much of total GA costs should be recovered according to the demand-based component (capacity-related costs) and how much should be recovered by the time-invariant volumetric component (fixed system costs), the OEB used three methods. The first compared the marginal cost of capacity to the total GA. Since this approach is highly sensitive to the value used to represent marginal cost, two other methods were also employed to verify results. It should be noted that each of the methods are top-down approximations, and no attempt is made to produce a comprehensive bottom-up supply-cost approach. A bottom-up supply-cost approach was not pursued because in addition to requiring extensive time and resources, it would require access to cost data that is not available in the public domain. The methods used are described in the following sections.

Method 1: Marginal Cost of Capacity

In this method, the marginal cost of capacity is used to estimate capacity costs in the GA. GA expressed in real dollars from 2021 to 2023 are used to calculate the average total GA cost.[30] Data prior to 2021 is not used since starting in this year, 85% of non-hydro renewable energy costs in the GA were shifted to the Province via the Comprehensive Electricity Plan (CEP). The maximum Allocated Quantity of Energy Withdrawn (AQEW) published by the IESO is used to represent maximum demand on the grid during the peak hour after accounting for embedded generation and storage.[31] These figures can be seen below in Table 5.

Table 5: Maximum AQEW and total GA from 2021-2023.

Year	**Maximum AQEW [MW]**[31]	**Total GA [real $2023]**[30]
2021	22,428	$ 9,312,751,871
2022	22,127	$ 6,345,235,664
2023	22,876	$ 8,532,483,106

[30] A breakdown of GA by components from January 2015 through September 2024 can be found at: https://www.ieso.ca/-/media/Files/IESO/Market-Summaries/GA-by-Components.xlsx.

[31] The IESO's top five peak hours and system wide consumption from May 2010 to April 2024 can be found at: https://www.ieso.ca/-/media/Files/IESO/settlements/Top-5-Peaks-Hours-and-System-Wide-Consumption.xlsx

Average	**22,477**	**$ 8,063,490,214**

Source: IESO

Two different values are used to estimate the marginal cost of capacity:

1. The net cost of new entry of a natural gas turbine.
2. The net cost of new entry of a combination of peaking resources as defined in IESO's May 2023 Resource Adequacy update by taking the capacity-weighted average.

Using value (1), the marginal cost of capacity is estimated as $644/MW-day in real 2023 dollars.[32] Assuming 252 business days per year, this value is $162/kW-year. Multiplying this value by the average maximum AQEW in Table 5 results in a capacity cost of $3,647,747,376. Dividing this by the average total GA from Table 5, 45% of GA costs can be attributed to capacity.

Using value (2), the IESO's May 2023 Resource Adequacy update (the most recent available at the time), the marginal capacity is estimated to be $567/MW-day.[33] Assuming 252 business days per year, this value is $143/kW-year. Multiplying this value by the average maximum AQEW in Table 5 results in a capacity cost of $3,212,990,464. Dividing this by the average total GA from Table 5, 40% of GA costs can be attributed to capacity.

Method 2: 2018 Market Surveillance Panel Report

In December 2018, the Market Surveillance Panel (MSP) published a report examining the impact of the ICI.[34] In that report, "The Panel estimates that payments to peaking resources make up less than 20% of the costs recovered through the Global Adjustment. The remaining 80% of fixed capacity costs are for non-peaking resources…" (page 19). The methodology used in the report to come up with those figures is summarized as follows:

- Non-peaking resources: all nuclear capacity, 50% of hydroelectric capacity, wind capacity, solar capacity, conservation programs and other.

[32] IESO Capacity Auction Price can be found at: https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/cae/cae-20221025-brattle-presentation.pdf

[33] IESO's May 2023 Resource Adequacy Update can be found at: https://www.ieso.ca/-/media/Files/IESO/Document-Library/resource-adequacy/ieso-resource-adequacy-update-May2023.pdf.

[34] More information on the ICI can be found at: https://www.oeb.ca/sites/default/files/msp-ICI-report-20181218.pdf.

- Peaking resources: all natural gas capacity and 50% of hydroelectric capacity.

Applying this methodology for the years of 2021-2023 inclusive, total GA consists of 67% non-peaking resource costs (fixed costs) and 33% peaking resource costs (capacity costs). This calculation was done using the IESO's GA by Components data,[35] converting the dollars into real 2023 dollars, summing them up by components and then assigning the components to peaking/non-peaking resources as shown below in Table 6. Data prior to 2021 is not used since this was the first year that 85% of non-hydro renewable energy costs were removed from the GA via the CEP.

Table 6: GA component costs for 2021-2023 and their respective assignments to peaking/non-peaking resources.

GA Components	Total for 2021-2023 (inclusive) expressed in $000,000 real 2023$	Per cent of costs allocated to non-peaking resources	Per cent of costs allocated to peaking resources
Conservation	600.3	100%	0%
Hydro	1,915.6	50%	50%
Nuclear (non-Ontario Power Generation)	6,973.9	100%	0%
Natural Gas	4,000.9	0%	100%
Other Programs – Industrial Electricity Incentive and Storage[36]	196.3	100%	0%
Financing Charges and Funds	(2.9)	100%	0%
Wind	5,306.6	100%	0%
Solar	4,877.4	100%	0%

[35] A breakdown of GA by components from January 2015 through September 2024 can be found at: https://www.ieso.ca/-/media/Files/IESO/Market-Summaries/GA-by-Components.xlsx.

[36] Note that this category is so small that no matter which resource type it is assigned to (peaking or non-peaking), it does not change the result.

Biomass, Landfill and Byproduct	653.0	100%	0%
Ontario Electricity Finance Corporation – Non-Utility Generation	130.6	0%	100%
OPG – Regulated Nuclear and Hydro[37]	9,238.4	69%	31%
Non-Hydro Renewables Funding Amount	(9,699.5)	100%	0%
Total GA Dollars Assigned to Each Resource Type		**16,278.0**	**7,912.5**
Per cent of Costs Allocated to Each Resource Type		**67%**	**33%**

Method 3: 2019 Ivey Report

In July 2019, the Ivey Business School's Energy Policy and Management Centre published a report[38] that examined the various components of the GA and how each component should be recovered. The table below from the report outlines the components and assigns them to 1) capacity, 2) OPG's energy price hedge and 3) system-wide (i.e., demand independent) costs.

[37] The allocations for OPG's regulated assets were determined using the installed capacities of OPG nuclear and hydro assets in 2023. These are 4,850 MW of nuclear and 7,624 MW of hydro respectively. More information on nuclear assets can be found at: https://www.opg.com/power-generation/our-power/nuclear/. More information on hydro assets can be found at: https://www.opg.com/power-generation/our-power/hydro/. 100% of nuclear and 50% of hydro assets were assigned to non-peaking resources to be consistent with the MSP report methodology.

[38] The 2019 Ivey Business School report can be found at: https://www.ivey.uwo.ca/media/3787287/dontleavemestranded-july-2019.pdf.

Table 7: 2017 GA costs by components.

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

Source: 2019 Ivey Report[38].

According to the Adjusted Totals in the final row of Table 7, approximately 30% of GA costs can be attributed to capacity, 10% to the energy price hedge and 60% to fixed system-wide costs. However, since this is prior to 2021, it does not account for the approximately $3 billion annually removed from the GA via the CEP. Assuming the non-hydro renewable energy costs removed from the GA are fixed costs, which is consistent with the 2018 Market Surveillance Report, approximately 40% of GA costs can be attributed to capacity, 15% to the energy price hedge and 45% to fixed system wide costs. For the purposes of this analysis, energy price hedge costs are combined with the fixed system wide costs. This is done because the energy price hedge is the difference between OPG GA costs and OPG capacity costs as outlined in the Ivey Report. Thus, 40% of GA costs can be attributed to capacity according to this method.

Results of Each Method Summarized

Each of these methods are approximations and should not be relied on individually to allocate capacity costs within the GA as they are limited by the data available and highly sensitive to the inputs used. While the marginal cost method is widely accepted and an argument could be made that it is the most accurate, the results vary considerably according to the value used to represent marginal cost. The method presented in the 2018 MSP report makes simplifying assumptions about which resources are used to meet peak demand. The 2019 Ivey Report approach is based on only one year's GA data (2017) with adjustments made to account for the removal of 85% of non-hydro renewable energy costs from the GA via the CEP beginning in 2021. Although each of these methods vary widely in approach and assumptions, confidence can be gained from the relatively consistent range of results from 33-45% of GA costs allocated to capacity. The results from each method are summarized in Table 8 below.

Table 8: Summary of GA capacity allocations by method.

Method	Per cent of GA Allocated to Variable Costs
1. Marginal Cost	40%, 45%
2. 2018 MSP Report	33%
3. 2019 Ivey Report	40%

To avoid false precision, a mid-range value of 40% can be concluded as a reasonable approximation of capacity costs in the GA. It follows that 40% of GA costs may be recovered according to the demand-based component and the remaining 60% may be recovered as a time-invariant volumetric component to reflect costs that do not depend on when electricity is consumed. This constitutes the DBHP, which is a more cost-reflective rate for recovering GA costs than the current Class B GA rate.

APPENDIX B: EIGHT ALTERNATIVE GA PRICE PLANS EXAMINED

The OEB developed eight candidate price plans based on the DBHP and are detailed in Table 9. The rates charged under each price plan are calculated such that they recover annual GA costs.

As outlined in Section 2.2, there were three price structures considered. These are RTP, TOU and TOU with CPP. RTP is simply the DBHP calculated on a forecast basis. The TOU price structures are based on defined ratios between on-, mid- and off-peak periods. These ratios are based on the load-weighted average demand-based component of the DBHP in each time period, depending on price plan. The TOU with CPP price structure is a TOU price plan with 30 periods of high prices each year with a duration of four hours each.

All TOU price plan periods are based on previous load studies and do not vary by season. The periods are defined the same way as for the ULO price plan periods except unlike ULO, they do not have a separate overnight price period (weeknights and weekends are both off-peak).[39]

[39] On-peak is 4 p.m. – 9 p.m. on weekdays, mid-peak is 7a.m. – 4 p.m. and 9 p.m. – 11 p.m. on weekdays and off-peak is 11 p.m. – 7 a.m. weekdays and all weekends and holidays.

In Table 9 below, the percentage of demand-based component is the percentage of GA collected as a function of provincial demand as expressed in Equation 2. Percentage of time-invariant volumetric component is the percentage of GA collected as a uniform volumetric price that does not change based on time of consumption.

Table 9: The eight candidate price plans assessed through the AMI analysis.

Price Structure	Candidate Price Plan	Definition	Rationale
RTP	RTP100	100% demand-based and 0% time-invariant volumetric component.	Included for consistency with 2019 OEB Staff Research Paper. The demand-shaped price from that paper did not include a time-invariant volumetric component.[40]
	RTP50	50% demand-based and 50% time-invariant volumetric component.	Included as a sensitivity on RTP40.
	RTP40	40% demand-based and 60% time-invariant volumetric component.	Most cost-reflective price design (see Appendix A: Development of the DBHP for more details).
	RTP30	30% demand-based and 70% time-invariant volumetric component.	Included as a sensitivity on RTP40.
TOU	TOU1	1 : 2.6 : 4.7 ratio of off-peak:mid-peak:on-peak based on average demand-based component of the RTP40 in each period.	Simplified approximation of RTP40.
	TOU2	1 : 2.6 : 10 ratio of off-peak:mid-peak:on-peak. Off-peak to mid-peak ratio based on TOU1. Off-peak to on-peak ratio based on RPP ULO price plan.	Simplified approximation of RTP40 with a higher ratio between on-peak and off-peak based on RPP ULO price plan.
TOU with CPP	TOU1-CPP	TOU1 with 30 four-hour CPP events per year.	Variation on TOU1. CPP showed positive results in the RPP Pilots.
	TOU2-CPP	TOU2 with 30 four-hour CPP events per year.	Variation on TOU2. CPP showed positive results in the RPP Pilots.

APPENDIX C: AMI ANALYSIS

Guidehouse assessed the potential individual customer bill impacts of each of the eight price plans described in Appendix B: Eight Alternative GA Price Plans Examined using a set of anonymized consumption data (AMI data) from four

LDCs that provided data to the OEB. Individual bill impacts provided the basis for Guidehouse to estimate the share of consumers likely to adopt a given alternative price plan. From this, Guidehouse estimated the potential short-term impact that adoption of an alternative price plan by some consumers could have on the bills of the other consumers that don't adopt the alternative price plan. These results can be seen below in Table 10. It should be noted that estimates of likely adopters are based on estimated savings only and do not consider customer preferences for simplicity and acceptability and the effects of perceived risk. These factors would likely have a downward influence on the RTP- and CPP-type price plans.

Table 10: Short-term bill impacts from AMI analysis.

Pricing Plan	Per cent of Likely Adopters	Avg. Consumption of Likely Adopters (kWh)	Avg. Bill Savings of Likely Adopters ($)	Per cent Bill Savings of Likely Adopters	Per cent GA Savings of Likely Adopters	Per cent GA Increase for All Other Non-RPP Class B Customers	Per cent Bill Increase for All Other Non-RPP Class B Customers
RTP100	14%	658,031	3,830	4.8%	8.7%	1.3%	0.7%
RTP50	8%	628,957	2,223	2.9%	5.3%	0.3%	0.2%
RTP40	6%	637,315	1,991	2.5%	4.7%	0.2%	0.1%
RTP30	5%	667,716	1,817	2.2%	4.0%	0.1%	0.1%
TOU1	10%	633,267	2,010	2.6%	4.8%	0.3%	0.2%
TOU2	16%	538,539	2,237	3.3%	6.3%	0.6%	0.3%
TOU1-CPP	13%	583,438	2,541	3.5%	6.6%	0.5%	0.3%
TOU2-CPP	19%	514,838	2,770	4.2%	8.1%	0.9%	0.5%

Source: Guidehouse.

The goal of this analysis was to identify the two price plans that most align with program objectives. Guidehouse's recommendations regarding each price plan are summarized in Table 11 below.

[40] Note that the value of one parameter, the exponent "w" (see Equation 1 in Appendix A), is eight instead of the original value, six. See Appendix A for rationale.

Table 11: Guidehouse's recommendations and conclusions for the eight candidate price plans.

Guidehouse Recommendation	Candidate Price Plan	Guidehouse Rationale
Proceed with customer interviews.	RTP40	As the most cost reflective, this price design will – assuming approximately equivalent adoption – deliver the outcome most aligned with maximizing long-term benefits.
	TOU1	TOU1 is a cost reflective and simplified option with minimal short-term disruption and higher estimated potential adoption than RTP40.
Exclude from further consideration.	RTP100	These price plans are not as cost reflective as other candidate price plans, which means that any long-term price response will be less economically efficient and fail to maximize long-term benefits.
	TOU2	
	TOU2-CPP	
	RTP30	RTP30 and RTP50 have approximately equivalent impacts on non-adopter unit energy costs as RTP40, meaning that none is preferred from the perspective of minimizing short-term disruption. All three price plans also have a similar number of likely adopters. However, RTP30 and RTP50 are not as cost reflective as RTP40, and therefore should not be brought forward.
	RTP50	
	TOU1-CPP	Guidehouse recommends that the TOU1-CPP price plan be excluded from further consideration, not based on the AMI analysis itself, but rather on the basis that the perceived customer risk of a CPP pricing element will likely result in substantially lower adoption than a simpler TOU price structure. Additionally, the provision of a CPP price signal not directly tied to a demand response program run by a system operator (bulk or distribution) risks reducing the capacity of such agencies to deliver system benefits through non-wires solutions.

APPENDIX D: PRICE SETTING, VARIANCE AND COST RECOVERY

Price setting inputs

Setting prices for either of the alternative GA price plans would require:

1. hourly provincial-level demand forecasts at least one year in advance from the time prices go into effect,
2. forecast of GA costs for Non-RPP Class B customers, and
3. adopter and non-adopter load profiles.

Item (1) can be achieved through the Reliability Outlook published each quarter by the IESO, which is what the OEB uses to set RPP prices. Item (2) is available on a yearly basis from RPP price setting. If alternative GA price setting is not done in sequence with RPP price setting (i.e., at a different time of year or more frequently), additional forecasts of GA would be required.

Item (3) is not available from any existing IESO or OEB data source and would need to be forecast specially for either of the alternative GA price plans. It would be used to allocate GA costs between adopters and non-adopters to ensure the resulting rate is cost reflective.

Variance

With any price plan set on a forecast basis, there will be a difference between the forecasted amount and the amount collected. This over- or under-collected dollar amount is called the “variance” and would need to be recovered via future prices. Following the RPP example, if an alternative GA price plan were offered to Non-RPP Class B customers, there would need to be an additional variance account created to track this variance amount.

Variance is likely to be much higher per dollar collected for any price plan that recovers only GA costs compared to a price plan that recovers all commodity costs (like the RPP price plans). This applies to both options presented, the Non-RPP TOU and the RTP. Many costs in the GA are a function of wholesale market prices because they are based on contracts that guarantee a volumetric price for energy supplied net any revenue from the wholesale market. Wholesale market prices can be volatile and difficult to predict since they are dependent on electricity demand, electricity supply, strategic bidding practices, global natural gas prices, and other factors. Therefore, the GA can also be volatile and difficult to predict. While wholesale market prices and the GA can be difficult to predict, their sum (the total commodity cost) is relatively stable due to their inverse relationship. When wholesale market prices are low, the GA tends to be higher and vice versa. Without both parts of the whole, variance is expected to be more volatile. This means that there is an increased risk of rate shock via fluctuating variance balances over time. In addition, if significant credit accumulates in a variance account there could be non-negligible costs of servicing that debt. This risk is somewhat mitigated by the fact that the GA costs of likely adopters are significantly lower than the total commodity costs of RPP customers (i.e., the total dollars that would be collected via an opt-in GA price plan for Non-RPP Class B customers are significantly lower than the total dollars collected by RPP price plans which cover both wholesale market costs and the GA).

To address this, the OEB recommends considering adjusting the price plans to recover all commodity costs (wholesale market costs and GA) as opposed to GA only.

Cost recovery

Each price plan considered is designed to recover GA costs in a more cost-reflective manner than the status quo GA rate that Non-RPP Class B customers pay today. The status quo Class B GA rate does not consider when electricity is consumed, so depending on when each customer consumes electricity, some customers are overpaying, and some customers are underpaying. If either GA price plan were implemented and *all* Non-RPP Class B customers signed up, some would pay less, some would pay the same and some would pay more. The difference is the distribution of GA costs across the customers would be commensurate with the costs they impose on the electricity system.

Adopters would be a subset of eligible customers who are likely to see sufficient savings. Since the alternative price plans are designed to be more cost reflective than the status quo, if a customer sees savings, they are part of the group that is overpaying for GA today. Therefore, on average, those who adopt will have a lower supply cost than those who do not which would result in a revenue shortfall. This revenue shortfall would be the difference in average supply cost between the adopters and the non-adopters, not a cross subsidization. Implementing a more cost-reflective alternative price plan would be unwinding the existing cross subsidization that exists within the Non-RPP Class B group. Therefore, this revenue shortfall should be recovered from customers who do not adopt the alternative GA price plan, otherwise implementing an alternative price plan would not have any of the short- or long-term benefits studied as part of this initiative. To accommodate this, the status quo Class B GA rate for Non-RPP Class B customers would need to be adjusted based on the difference in supply cost of the adopters and non-adopters.

APPENDIX E: GLOBAL ADJUSTMENT SETTLEMENT

The GA is settled monthly by the IESO. Class B customers pay their share of the GA based on the total amount of electricity they consume in a month. This is done through the status quo Class B GA rate which is calculated by IESO Settlements each month. The IESO calculates three variations of the Class B GA rate to accommodate various billing cycles of LDCs:[41]

1. 1st estimate, published no later than the last business day of previous month.

[41] More information on the Global Adjustment for Class B can be found at: https://www.ieso.ca/Sector-Participants/Settlements/Global-Adjustment-for-Class-B.

2. 2nd estimate, published no later than the last business day of the current month
3. actual rate, published no later than the 10th business day of the next month

For Non-RPP Class B customers, LDCs can use any one of the above rates for billing since they all include a true-up component to cover any over-collection or under-collection resulting from the previous month's published rate.

The first and second estimates are based on projections of both the total dollar amount for contracts and other programs in the month, as well as the total energy consumption for Class A, Class B, embedded generation and energy storage. The actual rate can sometimes vary considerably from the first and second estimates because the latter are based on forecast values that can change in unanticipated ways.

Class B RPP customers pay the GA through their RPP rates which are set on an annual basis. The difference between the GA amount paid and their allocated GA contribution (determined by their total energy consumption as a fraction of total Class B consumption) is carried forward in a variance account held by the IESO. LDCs submit settlement forms to the IESO to report the total energy consumed by RPP customers and the dollars collected from RPP customers. Although this pertains to Class B RPP customers as opposed to Non-RPP customers, this information is presented as a potential example of GA settlement for Non-RPP Class B customers price plans.

APPENDIX F: EVALUATION OF PROPOSED PRICE PLANS AGAINST RATE DESIGN PRINCIPLES

In Table 12 below, the two price designs are evaluated against James C. Bonbright's principles of just and economic rate making.[42] The Bonbright principles outline accepted rate design objectives and strategies to minimize unintended consequences. Two Bonbright principles have been omitted from the evaluation since they apply to rate setting as opposed to rate design.[43] While rate setting determines the costs to be recovered, rate design determines how to distribute those costs. The evaluation is presented below in Table 12, organized by the three program objectives.

[42] A detailed account of the Bonbright principles can be found on page 290 at: https://www.raponline.org/wp-content/uploads/2023/09/powellgoldstein-bonbright-principlesofpublicutilityrates-1960-10-10.pdf.

[43] The principles omitted are (1) yield total revenue requirements effectively in line with fair return standard and (2) provide stable revenue year-to-year.

Table 12: Evaluation of two alternative GA price plans against Bonbright principles.

Bonbright Principle	Non-RPP TOU	RTP
Program Objective 1: Cost Reflectiveness		
Promote efficient electricity use, in line with consumption patterns and system costs Ensure fair apportionment of costs to customers	The Non-RPP TOU is cost reflective because it is based on the DBHP. However, it is not as cost reflective as RTP since it aligns electricity prices with simplified demand patterns. This plan, although simplified, better aligns customer bills with the costs their consumption imposes on the electricity system when compared to the status quo Class B GA rate. Thus, Non-RPP TOU ensures a fairer apportionment of costs.	The RTP is the best approximation of a cost-reflective rate since it is based most closely on the DBHP. It reflects not only daily and seasonal demand patterns, but hourly demand patterns. The RTP most closely approximates the costs each customer imposes on the system through their electricity consumption. This ensures a fairer apportionment of costs when compared with the status quo Class B GA rate and the Non-RPP TOU.
Avoid discrimination in rate relationships	Both price plans are designed to recover the same total GA from Non-RPP Class B customers as the status quo rate today but in a more cost-reflective manner. Therefore, within the Non-RPP Class B group, introduction of either price plan would unwind existing subsidies that occur today as a result of the status quo Class B GA rate. The prices would not impact Class A or Class B RPP customers and therefore do not address the existing treatment of customers outside of the Non-RPP Class B group.	
Program Objective 2: Minimize Short-term Disruption		
Remain stable, with minimal unexpected changes	The Non-RPP TOU provides a stable, consistent GA pricing scheme that does not vary day-to-day until prices are reset.	The RTP is dynamic with respect to provincial demand, but consistent otherwise. Any changes in the rate are a result of changes in demand.
Program Objective 3: Feasible Implementation		
Simple, understandable, acceptable to the public and feasible to implement Free from ambiguity and misinterpretation	Ontario has offered TOU rates for residential and small business customers for over a decade. Since 2010, most electricity customers have paid for their electricity with a TOU rate structure, making TOU pricing well understood among customers. This further supports public acceptability, implementation feasibility and customer clarity of this price design.	The RTP rate structure is more complex than the TOU structure and more difficult for customers to understand. Customer interviews confirmed that it is generally acceptable, once understood. Collecting the GA via a price that varies hour-to-hour is possible since Non-RPP Class B customers pay hourly wholesale market prices today. There will, however, need to be additional billing and settlement system

	The Non-RPP TOU price structure does not vary day-to-day or by season. This makes it simple to understand and predictable for customers.	upgrades to accommodate it. Additionally, since automated day-ahead price calculations would be required, increased agency co-ordination would be needed to support its implementation.

APPENDIX G: SUMMARY OF STAKEHOLDER COMMENTS AND OEB RESPONSES

The OEB received written comments from 14 stakeholders in October 2024 as well as feedback from discussions and presentations at earlier stages of the initiative. The OEB relied on stakeholder feedback to inform its recommendations, specifically the selection of the Non-RPP TOU price plan, the timeline for potential rollout, implementation considerations and next steps. This section summarizes the OEB's response to additional questions and issues raised by some stakeholders in their written feedback.

Price Plan Preference and Design

Many written submissions, or eight of the 14 responses, alluded to support for the Non-RPP TOU only or both the Non-RPP TOU and the RTP. Of the remaining six responses, two asked for a reconsideration of CPP, one preferred RTP, one expressed no preference for either price plan, and two did not indicate a preference. Some of the written comments also suggested price design changes, including incorporating seasonality or a larger off-:mid-:on-peak ratio for Non-RPP TOU and addressing potentially low customer uptake or incentivizing other sector objectives. This section summarizes OEB's response to these comments.

1. ***Reconsider the CPP option(s)***: Two respondents suggested a reconsideration of the CPP structure for its ability to deliver benefits for system efficiency and deliver lower costs to customers in the medium and long term.

   OEB discussion: Two of the eight candidate GA price plans analyzed were CPP designs. CPP is less cost-reflective than the RTP price plans without providing the same level of certainty and simplicity delivered by the TOU price plans. The most cost-reflective TOU price plan and the most cost-reflective RTP price plan were chosen to move forward as two "goal posts" that represent the trade-off between simplicity and acceptability, and cost-reflectiveness. While offering a CPP price plan to

Non-RPP Class B customers could also deliver long-term benefits, it was not chosen for further study and consultation at this time.

Guidehouse also indicated that designing and deploying a price-incented demand flexibility program to support grid operations is more appropriately a bulk or distribution system operator task. The focus of this work is identifying opportunities to improve the economic efficiency of electricity consumption by better communicating system costs to consumers via the prices they pay.

2. ***Reflect seasonality in Non-RPP TOU***: Consider incorporating seasonal pricing trends into Non-RPP TOU to improve the cost reflectiveness of this alternative GA price plan.

   OEB discussion: The Non-RPP TOU was designed as a simple and predictable GA price plan based on the same cost-reflective basis as the RTP. The on-, off- and mid-peak periods are based on provincial load studies.[44] In rate design, providing simplicity and understandability typically involve a trade-off with cost reflectiveness. While a rate that fluctuates with demand and encompasses seasonal changes in electricity demand, like the RTP, would be more cost reflective, it is also important to provide customers with a stable and predictable price they can easily understand and accept.

3. ***Modify Off-:Mid-:On-Peak price ratio for Non-RPP TOU***: Three respondents suggested introducing larger differences between the Off-:Mid-:On-peak price ratio for Non-RPP TOU to provide a more effective price signal to customers.

   OEB discussion: While larger differences between prices over the different time periods would be more effective in driving behavioural response and load shifting, the objective of this initiative was to provide a cost-reflective rate. In the AMI Analysis, Guidehouse performed analysis for another TOU price structure, TOU2, that included a higher Off-:On-Peak price ratio (i.e., Off-:Mid-:On-Peak price ratio of 1:2.6:10 as opposed to the 1:2.6:4.4 of the Non-RPP TOU). This price design was found to be among the least cost reflective as it did not reflect provincial demand trends and the estimated long-term hourly system costs defined by the DBHP.

[44] Time periods are based on the *Design of an Optional Enhanced Time-of-Use Price* model that can be found at: https://www.oeb.ca/sites/default/files/Report-Design-of-an-Optional-Enhanced-Time-of-Use-Price-20220331.pdf.

4. ***Potentially low customer uptake****:* Due to marginal potential savings for many, customer uptake of an alternative GA price plan may be low. The benefits of offering an alternative GA price plan may be undermined by the costs LDCs incur to implement it and low customer uptake.

   OEB discussion: The purpose of this initiative is to offer customer choice through cost-reflective pricing options to a group of customers with no regulated price plan alternatives while minimizing short-term disruption. The AMI Analysis showed potential GA price plan adoption of 10% for Non-RPP TOU and 6% for RTP, as well as minimal bill increases for non-adopters (of 0.3% and 0.2%, respectively).

5. ***Alternative GA price plans do not incentivize other objectives***: Two respondents suggested that the two alternative GA price plan designs do not create strong enough incentives for behaviours that advance sector decarbonization and/or Distributed Energy Resource (DER) adoption.

   OEB discussion: The program objectives and guiding principles for price design were driven by considerations of: offering customer choice and cost-reflective price plan(s); minimizing short-term disruption for non-adopters; and considering feasible implementation. As a result, through this report and the recommended price plan(s), the OEB is not seeking to incentivize specific behaviours, including sector decarbonization and DER adoption. One stakeholder response also alluded to additional objectives for alternative price plan design, suggesting that other goals may increase costs for customers and affect affordability.

   However, since both the Non-RPP TOU and RTP plans vary with time, they could be beneficial towards DER or new technology adoption. One stakeholder response highlighted that the Non-RPP TOU could support air source heat pump adoption.

Implementation Considerations

In its targeted discussions and broader stakeholder meeting, the OEB sought feedback regarding the potential implementation of each price plan. At this stage, the OEB is recommending to proceed with the Non-RPP TOU in the short term based on stakeholder feedback on price plan design and implementation considerations.

Stakeholders have also highlighted the importance of completing further consultations to resolve specific implementation issues before LDCs are asked to make an alternative GA price plan available to Non-RPP Class B customers. For this purpose, the OEB has highlighted this feedback and enlisted specific implementation considerations.

6. ***Costly implementation for LDCs***: There are numerous activities required to be completed by LDCs to implement an alternative GA price plan based on the presented designs. These activities will result in additional costs for LDCs to make changes to: billing systems, vendor contracts, metering configuration, internal co-ordination efforts, regulatory and financial compliance, administrative processes, customer communication, deferral, variance and settlement procedures, and customer profile tracking. Furthermore, RTP would be even more complex than Non-RPP TOU and draw on more resources for LDCs to implement.

   OEB discussion: This feedback has been captured in this report (see Section 4.2). The OEB encourages further discussion and resolution of these implementation issues prior to the implementation of one alternative GA price plan. The OEB does not suggest implementation of RTP in the short term based on stakeholder feedback as well as the OEB's identification of the plan's greater complexity and potential implementation challenges outlined in Section 5.3. The OEB recommends future implementation of RTP if challenges for customer communication, local distribution company billing and settlement upgrades and automating day-ahead price setting for the implementation of RTP are overcome.

7. ***Timing of Rollout*****:** LDCs identified resource constraints in the short term owing to other initiatives affecting the sector (e.g., Market Renewal Program, Electric Vehicle Charger Discount Rate). Some stakeholders also provided timeline estimates for smoother implementation of an alternative GA price plan (e.g., a 9–18-month lead time).

   OEB discussion: Stakeholder feedback regarding resource constraints and proposed timelines were incorporated into the OEB's recommendation to implement the Non-RPP TOU in a phased manner, making the plan available from November 1, 2026 with a deadline of November 1, 2027.

8. ***Communications support needed***: LDCs and other stakeholders emphasized the importance of communication materials in ensuring sufficient uptake of an alternative GA price plan. LDCs have asked for further support from the OEB to provide materials to support customer education.

OEB discussion: During its engagement process, the OEB heard that many Non-RPP Class B customers depend on their LDCs for price plan education purposes. This report has described the types of communication materials and tools that LDCs and other stakeholders cited to support customer education efforts. If an alternative GA price plan will be implemented, this list of materials and tools will be revisited.

9. ***Eligibility and switching questions***: There remain questions about the eligibility and switching rules for an alternative GA price plan from stakeholders. These questions include whether Class A-eligible customers may be eligible for an alternative GA price plan and the frequency of price plan switching.

   OEB discussion: The OEB has captured these questions and concerns in its report for future discussions and consideration. Regarding eligibility, customers eligible for RPP pricing are not considered in the Non-RPP Class B group for the purposes of this initiative. This is because they have regulated price plan options available to them. Non-RPP Class B customers who are eligible but do not participate in Class A have been considered part of the Non-RPP Class B group as they are paying for electricity based on the status quo Non-RPP Class B rate.

Other

10. ***Calls for further study, consultation and/or pilots***: Four of the written responses mentioned the need for a more comprehensive review and assessment of the alternative GA price plans to determine potential customer uptake and bill impacts, LDC implementation processes and costs, and other short- and long-term market impacts. Some stakeholders requested the implementation of a pilot of each price plan and/or further consultation before the OEB recommends an alternative GA price plan.

    OEB discussion: Potential uptake, bill impacts and short- and long-term benefits and impacts are all detailed in this report (see Sections 5.2, 2.3 and 5.1, respectively).

    In 2022 and 2023, the OEB designed a program and invited stakeholders to submit applications to pilot alternative GA price plans. However, no final proposals were received. In lieu of the pilot, the OEB developed a consultation-focused and research-based approach to inform the development and recommendation of an alternative GA price plan for Non-RPP Class B customers. The OEB considers this information sufficient to recommend an alternative GA price plan design at this stage to the Minister of Energy and Electrification.

Based on stakeholder comments, the OEB has emphasized the need to resolve issues pertaining to price plan implementation prior to rollout. For future purposes regarding implementation, further research, assessment and/or consultation may be carried out depending on if and when any price plan or plans are moved forward to the implementation stage.