# Notice

**To:** AESO Stakeholders

**Date:** Tuesday, May 25, 2021

**Subject:** **NERA Economic Consulting Report on Estimated Customer Response to Preferred Rate Design**

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Further to the AESO's presentation of its Preferred Bulk and Regional Tariff Rate Design at its March 25, 2021 Stakeholder Session 5, the AESO received stakeholder feedback and certain questions from the Alberta Utilities Commission ("AUC") staff with respect to self-supply response to the Preferred Bulk and Regional Tariff Rate Design. In response to this feedback and the AUC questions, the AESO has posted a report prepared by NERA Economic Consulting entitled: Estimating Customer Response to Our Recommended Bulk and Regional Tariff Design (the "Customer Response Report"). The Customer Response Report will be discussed as part of the AESO's upcoming Bulk and Regional Tariff Design Stakeholder Session 6A on June 3, 2021, where stakeholders will have the opportunity to provide feedback on the report during that session and afterwards. The AESO is providing the Customer Response Report in advance of Stakeholder Session 6A to provide stakeholders additional time to review the document in advance of providing Session 6A materials on May 27, 2021. This is consistent with the AESO's Transparent and Timely Stakeholder Engagement Principle to assist stakeholders in understanding and evaluating the AESO's Preferred Bulk and Regional Tariff Rate Design.

Please direct any questions to tariffdesign@aeso.ca.



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# Estimating Customer Response to Our Recommended Bulk and Regional Tariff Design

Prepared for the AESO

25 May 2021

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# 1. Executive Summary

1. NERA Economic Consulting ("NERA") has been asked to estimate the likely customer response and potential changes in self-supply outcomes by load arising from the Bulk and Regional tariff design that we recommended to the Alberta Electric System Operation ("AESO"), as described at the AESO's Bulk and Regional Tariff Design Stakeholder Engagement Session 5. In this report, we describe our analysis of the anticipated customer response to the change in transmission tariff.

## 1.1. Our recommended tariff should encourage more efficient self-supply decisions by customers

2. Customers can reduce their costs of electricity by choosing to self-supply and generate power at their own premises instead of purchasing power from the grid. A customer's decision to self-supply balances the benefit associated with not consuming power from the grid with the additional costs that the customer incurs to self-supply power. A customer's choice to self-supply may be efficient and lower the total costs of electricity provision if the avoided system costs of serving that customers' self-supplied load from the grid exceeded the costs incurred by the customer to self-supply over the long-run.

3. However, customers cannot know the costs that their demand imposes on the grid. They rely on regulated transmission and distribution tariffs and wholesale market prices to signal, to the extent possible, the costs incurred to supply them. Therefore, transmission charges which are cost-reflective will tend to encourage overall efficient self-supply decisions by customers.

## 1.2. Marginal cost approaches to transmission tariff design may not promote efficient self-supply decisions without locational pricing

4. In theory, a marginal cost approach to transmission tariff design should send an efficient price signal, that reflects the costs imposed by incremental changes in demand on the system, through a charge which varies with customers' consumption behaviour. The remaining costs should be recovered in a way that avoids distorting the consumption decisions that customers take in response to the marginal cost component of the tariff.

5. Changes in customers' demands have different impacts on transmission system costs, depending on where they are located. The AESO provides transmission capacity to move electricity from areas where the supply of in-merit energy exceeds demand, to areas where demand exceeds supply. Therefore, increasing demand in areas of surplus in-merit energy may reduce transmission costs (implying a negative marginal cost), while higher demand increases transmission costs in areas where demand exceeds supply (implying a positive marginal cost).

6. In developing our recommended Bulk and Regional tariff methodology, we have been asked to assume that rates do not differ based upon the location of load on the transmission system. In the absence of the ability to differentiate the marginal cost component of the tariff by location, a tariff that reflects the marginal cost of transmission would be unable to account for the fact that the marginal cost of accommodating demand in some areas is likely to be positive, while the marginal cost of accommodating demand in other areas may be zero or even negative.

7. Therefore, a marginal cost-based tariff that applies in all areas cannot reflect these differences and therefore cannot send efficient signals regarding the marginal transmission costs associated with accommodating changes in demand in Alberta.

## 1.3. An embedded cost approach encourages efficient, long-run self-supply decisions

8. By contrast, an embedded cost methodology seeks to signal to customers the long-run costs of providing transmission, in a way that identifies which costs have been incurred historically to accommodate (or have been caused by) particular patterns of usage, particular customers and/or particular services. By ensuring that the structure of tariffs (the balance between fixed, demand-related, and energy-related tariffs), reflects the cost structure of the transmission grid, the tariff can encourage efficiency in users' self-supply decisions.

9. In the AESO's case, it is currently charging for the majority of transmisison costs through a 12CP charge, to an extent that is not justified on grounds of cost causation as explained in the Stakeholder Session 5 presentation. The current tariff is therefore promoting inefficient self-supply decisions aiming to avoid 12CP charges. By

contrast, our recommended tariff better reflects the dual purposes of transmission in Alberta: to meet peak demand and accommodate the flow of in-merit energy.

10. However, even if the tariff is designed to reflect the cost structure of the transmission system, and therefore promote efficient decisions to use the grid or self-supply in the long-term, there remains a possibility that a tariff set to recover historical costs will cause customers to inefficiently self-supply in cases where those customers make lower contributions to historical costs. We therefore estimate customer response to our recommended tariff using a modelling procedure.

## 1.4. We estimate that customer response to our recommended tariff is likely to be extremely limited

11. In order to better assess how customers may respond to our recommended transmission tariff, we model the optimal self-supply decisions for industrial sites in Alberta. Our approach follows three steps:

    A. Step 1: We construct a model that estimates the optimal self-supply decisions for industrial sites across Alberta, based on a simple comparison of the costs of purchasing power from the grid and self-generation costs.

    B. Step 2: However, this optimisation model overstates the actual self-supply for customers because we do not model other costs associated with self-supply such as costs and risks associated with business complexity or financing. To estimate how customers' actual self-supply decisions will be affected by a change in the transmission tariff, we estimate a regression equation to capture how likely customers are to self-supply, given the economic incentive to self-supply identified in Step 1.

    C. Step 3: We then use our regression to predict customers' response to the change in incentive to self-supply under our recommended tariff.

12. We estimate that self-supply could increase under our recommended tariff by up to 2,801 GWh which is equivalent to a shift in costs from self-supplying customers to other customers of approximately 1.90 per cent of the total revenue requirement for bulk and regional costs in 2019. Our estimate of customer response is a total effect

that includes any dynamic responses[1] by customers to self-supply decisions of other customers.

13. Our estimate of customers' response is conservative because it ignores the potential for customers to increase purchases of power from the grid in response to lower 12CP charges in our recommended tariff relative to the current tariff.

14. Hence, we predict an extremely limited increase in self-supply by industrial customers under our recommended tariff, and any change in customers' self-supply decisions that does arise will tend to result in more efficient patterns of electricity usage than under the current methodology.

## 1.5. The economic case for self-supply is likely to significantly worsen in the next decade due to rising gas and carbon prices

15. While the impact of our recommended tariff on self-supply is likely to be limited given the current costs of self-supply, the economic case for self-supply in Alberta is likely to worsen in the next decade, even under a low energy consumption growth scenario. Both carbon and gas prices are forecast to rise over the next decade. For instance, we understand that the Federal Government has announced that, under its carbon tax regime, taxes will increase from \$30 per tCO2 to \$170 per tCO2 in 2030.

16. The impact of future growth in gas and carbon prices on incentives to self-supply depends on how the costs of self-supply change relative to the pool price. Higher carbon and gas prices will increase the pool price for power, as generators incur higher costs to produce power, thereby increasing the cost savings associated with self-supply. On the other hand, rising gas prices and carbon prices will also result in higher costs of self-supply using gas-based generation, decreasing the cost savings associated with self-supply relative to purchasing power from the grid.

17. Gas-based generation options available for self-supply are generally smaller and therefore less efficient (requiring more gas to produce one unit of electricity) than grid-level generation plants. Consequently, the costs of self-supplying power will

[1] By the term "dynamic response", we refer to our modelling procedure accounting for some customers' decisions to self-supply pushing up tariffs for other customers, leading them to self-supply too. Our reported results consider these knock-on effects of the initial change in the tariff to our recommended design.

increase more than the pool price in response to higher carbon and gas prices, because self-suppliers require more gas (and release more emissions) to generate one unit of electricity.

18. We estimate that rising carbon and gas costs will make self-supply technologies more expensive over time, when compared to the cost of purchasing power from the grid. For two representative self-supply technologies, we estimate that by 2030, the fuel and carbon costs of producing one MWh using self-supply plant will be $25.40 or $32.47 per MWh (in real 2019 terms) more expensive respectively than producing a MWh using grid technology, relative to around $10 per MWh today. Therefore, we expect that upward pressure on fuel and carbon prices is expected to further reduce the incentive to self-supply.

# 2. Introduction

19. We have been asked by the Alberta Electric System Operator ("AESO") to estimate the likely customer response and potential changes in self-supply outcomes by load arising from our recommended Bulk and Regional tariff design, described at Bulk and Regional Tariff Design Stakeholder Engagement Session 5. In this report, we describe our analysis of the anticipated customer response to the change in transmission tariff.

20. Our report is structured as follows:

A. In Section 3, we discuss the factors that may influence a customers' decision to self-supply including the costs of self-supply options and the costs of purchasing power from the grid, and determine whether such decisions are efficient:

i. In Section 3.1, we discuss the definition of efficient and inefficient self-supply decisions.

ii. In Section 3.2, we discuss the ability of marginal and embedded cost tariff methodologies to promote efficient self-supply decisions in the Alberta context.

iii. In Section 3.3, we provide a short discussion of current self-supply choices made by customers in Alberta under the current tariff.

iv. In Section 3.4, we analyse the impact of our recommended tariff on the decision to self-supply. We provide the results of our modelling procedure developed to examine how changes in the AESO's tariff affect self-supply decisions by industrial customers. Overall, we find that any reduction in energy demand from the transmission system resulting from changing to our recommended tariff design is likely to be extremely limited, based on the current costs of self-supply.

v. In Section 3.5, we examine how incentives to self-supply are likely to change in the future due to forecast changes in the economics of self-supply. We find that the economics of self-supply are set to worsen in the future, even under a low consumption growth scenario, because self-supply technologies are impacted by rising carbon prices to a greater extent than grid level technologies.

B. In Section 4, we summarise our findings.

C. In Appendix A, we provide a detailed description of our modelling procedure used to estimate customer response, as reported in Section 3.4.

# 3. Customer Response to the Tariff

## 3.1. The Decision to Self-Supply

### 3.1.1. A customers' decision to self-supply

21. Customers can reduce their costs of electricity by choosing to self-supply and generate power at their own premises instead of purchasing power from the grid. A customer's decision to self-supply balances the benefit associated with not consuming power from the grid with the additional costs that the customer incurs to self-supply power.

22. Customers that choose to self-supply incur costs to do so. The costs of self-supply may include:

    A. The upfront **capital costs** associated with building or procuring a generator to use for self-supply, which would usually be depreciated and financed over the useful life of the generator;

    B. The **fixed annual operating and maintenance (O&M) costs** of generating power using the installed generator;

    C. The **variable costs** associated with generating power which may include the variable O&M costs of the generator, the costs of fuel for the generator, and the carbon costs associated with using fossil fuel generation; and

    D. **Other costs** associated with self-supply such as the costs of land for the generator, personnel, administrative costs, and costs associated with any additional complexity and risk to business operations relative to purchasing power from the grid.

23. The costs of self-supply may also be offset if an industrial customer uses a bi-product from generating its own power in its industrial processes. For instance, industrial customers that self-supply power using cogeneration technology may also benefit from using heat and/or steam in industrial processes.

24. A customer that chooses to self-supply also avoids the costs of purchasing that self-supplied power from the grid. A customer that chooses to consume power from the grid incurs multiple costs, that primarily consist of:[2]

   A. **Energy costs** associated with purchasing energy from the pool;

   B. **Transmission charges** as defined by the ISO tariff for use of the transmission system;

   C. **Distribution charges**, paid by distribution connected customers, for the use of the distribution system;

   D. **Local access fees** which are fees charged by municipal districts to customers in those service areas; and

   E. **Administrative charges**, for customers which purchase energy through an electricity retailer, associated with the billing and administration of the customer's account by the retailer.

25. The costs that customers avoid from self-supplying and incur from purchasing power from the grid depend on how and when they use electricity:

   A. Depending on their connection to the system, customers may not have to pay all of the above charges when consuming electricity from the grid.

      i. A transmission connected, industrial customer purchasing power from the grid would incur energy costs and transmission charges.

      ii. An industrial customer purchasing power from the grid but connected to a distribution system might incur energy costs, transmission charges, and distribution charges.

   B. Customers pay different amounts in energy, transmission, and distribution charges depending on when they purchase electricity from the grid. For instance, customers consuming at peak times will likely pay higher energy costs because the pool price tends to be higher and may also pay more in transmission charges if they consume during times of coincident peak. Other charges, such as a flat

[2] AESO (31 May 2020), Delivered Cost of Electricity Report, p. 15.

rate energy charge would be incurred irrespective of when customers consume from the grid.

C. Charges levied per customer do not vary depending on how much or when the customer consumes energy from the grid. Such charges are difficult to avoid through self-supply decisions, unless customers disconnect from the grid entirely.

D. Charges levied on billing capacity do not vary with customers' energy consumption across all hours, but do vary with customers' contracted capacity or peak energy consumption across the year. However, customers choosing to self-supply may reduce their contracted capacity as having generation on-site may reduce their reliance on the grid for peak requirements.

26. Therefore, customers incur different costs to self-supply and avoid different costs associated with purchasing power from the grid, depending on how and when they choose to self-supply.

27. A customer's decision to self-supply is not a binary decision. There are multiple different ways that a customer could self-supply that each result in a different net consumption profile from the grid. We distinguish four approaches and technologies that could be used to self-supply:

A. **Intermittent generation:** Customers could install intermittent generators to self-supply such as rooftop solar photovoltaic (PV) generators. The profile of such generation is not controllable by the customer and therefore the customer would still need to connect to the grid or install other forms of on-site generation that could run when the intermittent resource is not available. The customer would avoid paying some costs when it was generating, such as energy charges in the transmission tariff and the pool price. However, it would tend not to avoid peak charges, except to the extent that the generator happens by chance to be producing at peak time.

B. **Peaking generation:** Customers could install peaking generators characterized by low capital costs but high variable costs of generation. Customers can choose when to run peaking generation and would likely use it to reduce their consumption during peak periods, when they can avoid network charges linked to coincident peak load, energy charges, and energy costs associated with higher pool prices. However, peaking generators will be less economic to run in off-peak periods meaning customers would likely remain connected to the grid and consume power from the grid during those times.

C. **Baseload generation:** Customers could install baseload generators, characterized by higher capital costs but lower variable costs of generation relative to peaking generators. Baseload generators will be economic in more hours than peaking generators, and could be used to self-supply in all hours throughout the year. However, customers deploying baseload technologies for self-supply would still need to be connected to the grid as they would be reliant on the grid for back-up in cases where their generator suffers a forced outage. Customers with baseload generation would avoid most energy costs and charges, apart from the occasions where it relied on the grid for back-up, and peak charges, unless it needed to use the grid for back-up during a peak period. However, customers would remain liable for any per customer, per connection, or contract capacity charges as they would remain connected to the grid. As we discuss above, customers may also utilise baseload generation to produce bi-products for use in industrial processes.

D. **Disconnection or grid defection:** Lastly, customers could completely disconnect from the grid, and rely entirely on their own power generation capacity. Customers that disconnect from the grid would avoid all energy costs, transmission charges, and distribution charges. However, they may incur higher costs to self-supply, as they would need to have technology in place to operate in an “islanded” mode of operation, without the ability to draw on the grid for support.

28. Customers can also avoid taking power from the grid at certain times to avoid charges, but without investing to self-supply. Management of load, by reducing or eliminating power consumption, can be used to avoid coincident peak charges which are levied on consumption during small time intervals throughout the year, or the purchase of energy at relatively high pool prices. However, customers would need to be able to predict when such time intervals occur. In management of their load at any

moment in time, customers face a trade-off between the opportunity cost of using power and the savings associated with avoiding the charges levied.

29. Customers may also invest in energy storage options to complement self-supply technologies or to help them manage their load and avoid periods of time associated with relatively higher costs of purchasing power from the grid.

30. Customers' decisions on how and whether to self-supply depend on their individual circumstances, namely how and when they consume power from the grid. A customer considering whether to self-supply could choose a combination of the approaches to self-supply (listed in Paragraph 27 above) to best meet its energy requirements.

31. In making self-supply decisions, a customer's load size is also an important determinant of the self-supply options available to it. The upfront capital costs of some self-supply options, e.g. baseload generators, often make them uneconomic for customers with smaller loads. Customers with smaller loads may be limited to smaller back-up/peaking plant, intermittent generation options, and load management. On the other hand, larger industrial and commercial customers are more likely to be able to pursue a wider range of self-supply options, including peaking and baseload generation or disconnection from the grid.

32. Customers are also constrained in their decisions to self-supply by other factors. Space and land availability may constrain the use of some self-supply options, such as the use of solar PV for larger industrial loads. Local emissions limits may also restrict the self-supply options available to customers. Lastly, industrials may face capital constraints in funding the upfront capital costs of self-supply options.

33. From the customers' perspective, optimal decisions to self-supply balance the costs incurred to generate their own power with the avoided costs of purchasing power from the grid. We would expect customers to take a holistic decision of whether to self-supply based on all the benefits and avoided costs of purchasing power from the grid (i.e. not just the transmission tariff).

A. If the customer incurs fewer costs to self-supply than it would to purchase power from the grid (accounting for any associated benefits of self-supply, such as heat supply), then the customer would optimally choose to self-supply.

B. If the customer incurs more costs to self-supply than it would to purchase power from the grid (even after accounting for associated benefits of self-supply), then the customer would optimally choose not to self-supply.

34. Given that self-generation decisions typically involve investment in long-lived generation assets, we would expect a customer's decision on whether to self-supply to consider a forward-looking assessment of the costs of self-supply relative to the avoided costs of consuming from the grid.

### 3.1.2. Efficient and inefficient self-supply decisions

35. Economics defines a concept named "productive efficiency".[3] A market is productively efficient when it meets the demand from customers at lowest possible cost. The power market would achieve productive efficiency if customers' loads are met at lowest possible system costs, irrespective of which parties incur those costs.

36. It is not necessarily inefficient for the system if customers choose to self-supply. In fact, a customer's choice to self-supply may be efficient and lower the total costs of electricity provision:

A. A customer choosing to self-supply would improve productive efficiency if the avoided system costs of serving that customers' self-supplied load from the grid exceeded the costs incurred by the customer to self-supply over the long-run (net of any other costs and benefits from doing so, such as the value of heat); whereas

B. A customer choosing to self-supply would reduce productive efficiency if the avoided system costs of serving that customers' self-supplied load from the grid are less than the customer's incurred costs to self-supply over the long-run (net of any other costs and benefits from doing so, such as the value of heat).

37. Customers cannot know the costs that their load imposes on the grid. They rely on regulated transmission and distribution tariffs and wholesale market prices to signal, to the extent possible, the costs incurred to supply them. Therefore, transmission

[3] See for instance, Michael. J. Farrell (1957), The Measurement of Productive Efficiency, Vol. 120, No. 3, p. 253-290.

charges which are cost-reflective will tend to encourage overall efficient self-supply decisions by customers.

38. Following a change in the transmission tariff, customers may make different, and *more efficient*, self-supply decisions in response to a transmission tariff that itself better reflects the costs of transmission incurred to serve that customer's load. For instance, compared to the current tariff, our recommended tariff reduces costs recovered through a charge on 12CP in order to better meet principles of cost causation. Consequently, customers are more incentivised to consume power from the grid during times of coincident peak, thereby reducing inefficient self-supply decisions relative to the current tariff.

39. In its Distribution System Inquiry, the Alberta Utilities Commission (AUC) distinguishes customers' decisions to self-supply by whether they constitute "economic" or "uneconomic bypass" from the grid.[4] The AUC defines uneconomic bypass:[5]

> *"uneconomic bypass describes a situation where a customer's bypass decision (i.e., supplying its needs through other means) shifts fixed cost recovery, whether in whole or in part, to other customers. This occurs when a customer's decision to self-supply electricity does not change (or even increases) system costs, but results in that customer paying a smaller share of the fixed costs. This unrecovered fixed cost must then be collected from other customers"*

40. The AUC defines "economic bypass":[6]

> *"In contrast, economic bypass occurs when a customer supplying its needs through other means results in reduced costs for other customers. This happens when a customer's decision to self-supply electricity lowers system costs; so it is not only the self-supplying customer who is paying less for the system costs, but the costs for other customers are also reduced"*

[4] AUC (19 February 2021), 24116-D01-2021, Distribution System Inquiry, para. 97 and 98.

[5] AUC (19 February 2021), 24116-D01-2021, Distribution System Inquiry, para. 97.

[6] AUC (19 February 2021), 24116-D01-2021, Distribution System Inquiry, para. 98.

41. As we discuss above, our recommended tariff seeks to more accurately signal the long-run costs of providing transmission in Alberta. Self-supply decisions in response to cost reflective tariffs promote efficiency in the overall supply of electricity, and will tend to reduce the costs faced by the customers who purchase energy from the grid. Changes to customers' self-supply decisions in response to our recommended tariff should therefore tend to be more efficient than under the current tariff, resulting in incentives that will encourage what the AUC terms economic bypass (and discourage uneconomic bypass) in the long-run than the current tariff design.

42. However, even though our recommended tariff seeks to better reflect the cost structure of the transmission system than the existing tariff in order to promote efficient decision-making on customers' usage of the grid or self-supply decisions, there remains a risk of inefficient self-supply decisions. Specifically, any tariff has to recover the current operating and historically incurred capital costs of the transmission system in Alberta. If the costs incurred historically are higher than the costs that would be associated with the costs of meeting customers' demands for electricity in the future, then there is a risk that any tariff set to recover historical costs will cause customers to self-supply.

43. In other words, customers that respond to the price signals sent by the recommended tariff design might make lower contributions to historical costs, thereby shifting recovery of those costs to other customers. As explained below, marginal cost pricing provides a potential solution to this challenge that has been discussed in the context of distribution tariff reform in Alberta.

## 3.2. Marginal Cost Tariffs as a Possible Means of Promoting Efficient Self-Supply Decisions

### 3.2.1. Theory suggests marginal cost tariffs promote efficient self-supply decisions

44. Economic theory, and the practical application of rate design in North America and elsewhere, sometimes uses a "marginal cost approach" as a potential solution to this problem of historical costs exceeding the forward-looking costs associated with future changes in demand for electricity. The marginal cost approach sets tariffs based on an

estimate of how a change in demand from a customer will affect the future costs of the utility.[7]

45. A theoretical advantage of a marginal cost approach is the ability to send an efficient price signal that reflects the costs imposed by incremental changes in demand on the system. This price signal should be sent through a charge which is "avoidable" or varies with customers' consumption behaviour. In theory, these prices promote efficiency by allowing customers to trade-off the benefits they derive from consuming electricity drawn from the transmission system, which may include the value derived from consumption or the costs of alternative self-generation options, against the transmission costs their consumption creates (as well as other costs such as the wholesale market price).

46. The concept of marginal cost-based pricing is discussed in the context of distribution network rate design in the AUC's Distribution System Inquiry:[8]

> *"distribution rates should contain a variable component to provide a forward-looking price signal to customers to manage their use of distribution system services that will affect the future costs of the network. This forward-looking component is based on variable charges (volumetric charges or avoidable demand, such as CP charges)"*

47. However, setting prices equal to an estimate of marginal cost will not usually (except by coincidence) generate enough revenue to recover the revenue requirement.[9] The difference between the revenue earned under marginal cost prices and the revenue requirement is often called the "residual" costs.

48. Consequently, in order to recover the revenue requirement efficiently, the marginal cost methodology prescribes that the residual should be recovered in a way that avoids distorting the consumption decisions that customers would take in response to the

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[7] National Association of Regulatory Utility Commissioners (NARUC), Electric Utility Cost Allocation Manual, January 1992, pp. 12-14.

[8] AUC (19 February 2021), 24116-D01-2021, Distribution System Inquiry, para. 311.

[9] NARUC, Electric Utility Cost Allocation Manual, January 1992, p. 147.

 

efficient price signals conveyed by marginal cost component of the tariff alone. As explained in the AUC's Distribution System Inquiry:[10]

> *"Whenever an attempt is made to recover embedded or sunk costs (also referred to as "residual costs" in the quote above) through charges that customers can avoid (such as volumetric charges or CP demand charges), improper incentives (i.e., incentives contrary to the public interest in the least cost provisioning of electricity) arise to invest in self-supply, resulting in (i) under-recovery of fixed system costs; (ii) cost shifting to other customers; and (iii) uneconomic bypass"*

49. In light of the above, methods to recover residual costs in a marginal cost-based tariff include:

    A. Ramsey pricing, which recovers residual costs based on the relative elasticities of demand for different classes of customers.[11] Those classes with the highest price sensitivity will be charged the price closest to marginal cost (hence recovering less residual cost) while those that are least likely to respond to price will be charged the price that deviates the most from marginal costs (reflecting more residual costs).[12]

    B. However, recognising that it can be challenging to identify the price elasticity of demand for all customers, the tariff could recover residual costs based on a charge levied on a billing determinant which is least likely to distort customer behaviour (and the price signal sent by the marginal cost component of the charge).[13]

    C. Another method to recoup residual costs is to apply a proportional mark-up to the marginal-cost component of the charge.[14] While this approach is simple to administer, and can result in a similar outcome to Ramsey pricing if customer classes that impose the highest marginal costs also have the least price elastic

[10] AUC (19 February 2021), 24116-D01-2021, Distribution System Inquiry, para. 310.

[11] The elasticity of demand describes the extent to which customers can and are willing to change their behavior to avoid the charge. A higher elasticity of demand refers to a customer that is more willing to change their behavior to avoid the charge.

[12] NARUC, Electric Utility Cost Allocation Manual, January 1992, p. 155-160.

[13] NARUC, Electric Utility Cost Allocation Manual, January 1992, p. 162.

[14] NARUC, Electric Utility Cost Allocation Manual, January 1992, p. 160-162.

demand, this methodology distorts the marginal cost price signal, and so undermines the efficiency properties of marginal cost pricing.

50. The choice of methodology to recover residual costs should also consider the equity of the tariff design.[15] For instance, levying a fixed charge per customer may disproportionately impact smaller customers relative to larger ones.

### 3.2.2. Challenges of applying a marginal cost approach to set the AESO's tariff

51. While the marginal cost approach is theoretically appealing as a means of encouraging efficient self-supply decisions, the current legislative framework in Alberta significantly limits the potential benefits of using a marginal cost approach in the AESO's tariff.

52. The efficiency of a marginal cost approach to set a regulated utility tariff that will apply to a wide set of customers (e.g. across a whole "class" of ratepayers) relies on the assumption that all such customers' consumption decisions would have a similar impact on the utility's costs. For instance, in a distribution system, it is reasonable to assume that changes in customers' consumption decisions (or growth in the number of customers) will have a similar effect on the distribution utility's costs because the majority of residential electricity customers have similar sized connections and are served with similar types of infrastructure.

53. In a transmission system, by contrast, it is not safe to assume that changes in all customers' demands have the same impact on the transmission system's costs:

A. New demand connecting to the system in a location that is close to new generation may help the AESO to avoid the need to reinforce the transmission system to evacuate power from the new generation facility. As such, the marginal cost of accommodating this particular change in demand would be negative.

B. On the other hand, additional energy consumption in locations near generators due for retirement, or in locations where demand is already high relative to the

[15] NARUC, Electric Utility Cost Allocation Manual, January 1992, p. 164-165.

generation located nearby, may increase transmission costs. The marginal cost of accommodating such changes in demand would be positive.

54. In practice, the investments that the AESO identifies in the 2020 Long Term Plan (LTP) suggest that changes in customers' consumption decisions (e.g. demand, energy) in different locations of the network could be associated with different amounts of avoidable costs. For instance, while the AESO is currently only planning a single investment in the Northeast planning region to support voltage, it is planning multiple new single-circuit lines to alleviate *load* thermal constraints in the Northwest, two new bulk line circuits in the Central planning region to alleviate *generation* thermal constraints, and a new regional line in the Calgary planning region to alleviate *load* thermal and voltage constraints. Hence, changes in customers' consumption decisions in Calgary are unlikely to drive the same change in transmission costs associated with the identified investments in the Northwest as changes in customers' consumption decisions in the Northwest.

55. In developing our recommended Bulk and Regional tariff methodology, we have been asked to assume that rates cannot differ based upon the location of load on the transmission system. In absence of the ability to differentiate the marginal cost component of the tariff by location, a tariff that reflects the marginal cost of transmission would be unable to account for the fact that the marginal cost of accommodating demand in some areas is likely to be positive, while the marginal cost of accommodating in other areas may be zero or even negative.

56. Therefore, the marginal cost component of the tariff would inevitably differ from the marginal cost of transmission investment associated with accommodating an additional unit of demand at that particular location of the network. As such, a tariff set using a marginal cost approach would not necessarily lead to an efficient outcome.

57. To take a practical example, the electricity transmission pricing methodology in Great Britain sets tariffs that seek to approximate the long-run marginal cost of transmission, such that transmission users receive a forward-looking signal regarding the costs they impose on the grid. However, the primary purpose of these forward-looking signals is to send locational signals regarding the long-run investment cost

users impose on the grid in different *locations*, with charges for demand customers varying from £20.38 to £61.68 ($35.33 to $106.91) per kW per year, depending on location.[16] Customers also pay a non-locational charge per kW to cover residual costs.

58. Hence, even if marginal cost-based distribution tariffs may have the potential to encourage the efficient use of distribution systems in Alberta, the legislative framework in Alberta limits the potential benefits of a marginal cost methodology to set *transmission* tariffs. The relative importance of locational signals at the transmission system level compared to the distribution system level is recognised in the Distribution System Inquiry:[17]

> *"experts indicated that while there may be merits of locational pricing on the transmission system, there probably is much less value in locational pricing on the distribution systems, at this time"*

59. Whilst we assess that the use of a marginal cost-based approach for transmission pricing in Alberta is principally limited by the inability to vary the marginal cost component of the tariff by location, using such a methodology to set transmission tariffs would also entail challenges associated with the recovery of the remaining residual costs:

A. The large increase in transmission investment seen since 2014 has not been accompanied by significant growth in coincident peak demand.[18] Over this historical period, load growth has also been relatively low. Consequently, we would expect a tariff based on a marginal cost approach to have a small marginal cost component and large residual cost component. Large residual cost components of the tariff create challenges for the recovery of those costs, whilst

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16 Half-hourly demand tariff reported for zones in Northern Scotland and South Western in Transmission Network Use of System Tariffs in 2021-22. See: National Grid (January 2021), Final TNUoS Tariffs 2021-22, Table 9. Currency converted using current exchange rate of GBP 1: 1.73 CAD.

17 AUC (19 February 2021), 24116-D01-2021, Distribution System Inquiry, para. 317.

18 AESO (10 December 2020), Bulk and Regional Tariff Design Stakeholder Engagement 4, Slides 47-48, available at https://www.aeso.ca/assets/Uploads/Presentation-Session-5.pdf.

preserving the efficient price signal sent by the marginal cost component of the tariff.

60. As we explain above, under a Ramsey pricing approach, residual costs could be recovered from customers in proportion to their estimated price elasticities of demand (higher charges levied on customers with lower price elasticities of demand). However, estimating the price elasticity of demand for different customer groups is difficult in practice. Moreover, it involves levying costs on customer classes based on their willingness and/or ability to respond to charges. This approach would not seek to follow principles of cost causation but instead target the minimal customer response to the residual component of the tariff. The approach may also raise equity concerns.

61. Hence, a more practical implementation might be to levy the residual costs on billing determinants that are less likely to produce a response from the customer. For instance, the Distribution System Inquiry states that residual costs should be recovered from billing determinants that are non-avoidable, or difficult to avoid, such as fixed monthly charges or "non-bypassable demand charges" such as non-coincidental peak demand or contract capacity charges.[19]

62. However, unlike distribution systems, a relatively small number of customers are connected to the transmission system, and they vary materially in terms of their size usage of the system. For instance, transmission customers comprise small and large industrials, some of which make very little use of the grid except as a back-up to on-site generation, as well as distribution systems. Therefore, levying a fixed fee per customer or connection point to recover transmission residual costs would not follow principles of cost causation, and is likely to lead to inequitable charges as small customers would make the same financial contribution to residual costs as much larger customers.

63. In addition, it is not clear whether any billing determinant would be truly "non-avoidable" for many transmission customers. As explained above, large industrial customers that connect directly to the transmission system can choose to reduce their coincident or non-coincident demand by self-generating, or disconnecting from the

[19] AUC (19 February 2021), 24116-D01-2021, Distribution System Inquiry, para. 309.

grid and self-supplying the entirety of their energy needs. High transmission charges could also make it uneconomic to operate within Alberta. Hence, even a fixed charge per customer per month may be avoidable for a large industrial customer connected to the transmission grid.

64. As noted above, as an alternative to recovering residual costs from the customers with least price elastic demand or the billing determinants that are least avoidable, an alternative approach would be to use proportional mark-ups to uplift marginal cost-based tariffs. In this case, it is likely that proportional mark-ups would need to be large given the relative size of residual costs relative to marginal costs. Therefore, proportional mark-ups will likely significantly distort any price signal sent by the marginal cost component of the charge.

65. However, as noted above, the limitations associated with efficient recovery of residual costs are secondary to the limitations associated with the inability of the transmission tariff to accurately reflect marginal cost unless it has locational differentiation.

### 3.2.3. The lack of locational pricing would restrict or negate the efficiency benefits from the AESO introducing a marginal cost methodology

66. Economic theory shows that marginal cost prices may send more efficient signals to consumers of the impact of changes in load on the costs of transmission. However, these theoretical benefits of a marginal cost approach cannot be realised in the AESO's context, if rates of the transmission tariff do not differ based upon the location of load on the transmission system.

67. In simple terms, the AESO provides transmission capacity to move electricity from areas where the supply of in-merit energy exceeds demand, to areas where demand exceeds supply. Increasing demand in areas of surplus in-merit energy may therefore reduce transmission costs (implying a negative marginal cost), while higher demand increases transmission costs in areas where demand exceeds supply (implying a positive marginal cost). A marginal cost-based tariff that applies in all areas cannot reflect these differences and therefore cannot send efficient signals regarding the marginal transmission costs associated with of accommodating changes in demand in Alberta.

### 3.2.4. An embedded approach will tend to promote more efficient self-supply decisions than a marginal approach in the Albertan context

68. The AESO's current tariff methodology is an embedded cost approach. In contrast to the marginal cost approach, which aims to set a forward-looking signal regarding the additional costs that would be associated with future load growth, the embedded cost approach designs tariffs based on historical spending on capital investment and operating expenses during a specific time period.[20]

69. In this context, the embedded cost methodology seeks to signal to customers the long-run costs of providing transmission, in a way that identifies which costs have been incurred historically to accommodate (or have been caused by) particular patterns of usage, particular customers and/or particular services. Embedded methodologies need to be designed to achieve this objective, and thereby send signals to users regarding the historical costs associated with their usage of the transmission grid.

70. By setting charges to reflect the costs incurred historically to serve particular customers or types of grid usage, the embedded methodology can send signals through tariffs that reflect such patterns of cost causation. By ensuring that the structure of tariffs (the balance between fixed, demand-related, and energy-related tariffs), reflects the cost structure of the transmission grid, the tariff can encourage efficiency in users' self-supply decisions.

71. The embedded cost approach is commonly criticized for sending less efficient price signals to consumers, because prices may not reflect the cost of consuming the next unit of electricity. Instead, prices reflect the historical, average cost of service, so consumption decisions made in response to the tariff may be less efficient than if the tariff were set equal to marginal cost. However, in this particular context, i.e. electricity transmission in a jurisdiction where locational differentiation of transmission tariffs is not permitted, this common criticism of the embedded methodology would be unjustified. As we explain above, the AESO's Bulk and

[20] National Association of Regulatory Utility Commissioners (NARUC), Electric Utility Cost Allocation Manual, January 1992, pp. 12-14.

Regional tariff cannot accurately reflect the marginal cost of transmission without differing rates based upon the location of load on the transmission system.

72. Given this limitation of marginal cost-based pricing in this context, an embedded methodology provides a reasonable guide to the costs associated with particular customers' usage of the transmission system. We therefore recommend that a tariff based on an embedded cost approach is more likely to promote efficient self-supply decisions than a tariff based on marginal cost pricing principles.

73. Nonetheless, we quantify the likely effect of our recommended tariff design (as outlined in the presentation delivered at Stakeholder Session 5) on self-supply decisions by customers, as described further below.

## 3.3. Self-Supply in Alberta

74. As we discuss in Section 3.1.1, industrial customers tend to have a larger number of options to self-supply than residential or small commercial customers because they have larger loads. Industrial customers account for approximately 65 per cent of annual Alberta Internal Load ("AIL"). The remaining load comes from commercial customers (20 per cent), residential customers (13 per cent), and farms (3 per cent).[21]

75. Some industrial customers are already self-supplying under the current tariff. Approximately 24 per cent of annual AIL is self-supplied, or roughly 37 per cent of industrial load.[22] We understand that industrial customers choosing to self-supply include those with petrochemical facilities, pulp/paper and forestry facilities, and oil sands customers. In particular, we understand that oil sands industrial customers have invested in cogeneration self-supply options, and benefit from the production of heat for use in their production processes.[23]

76. The majority of remaining industrial customers which are not pursuing self-supply options are distribution-connected. Approximately 6 per cent of total AIL comes

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[21] AESO (31 May 2020), Delivered Cost of Electricity Report, p. 9.

[22] AESO (31 May 2020), Delivered Cost of Electricity Report, p. 9.

[23] AESO (31 May 2020), Delivered Cost of Electricity Report, p. 9.

from transmission-connected industrial customers which are not currently self-supplying.

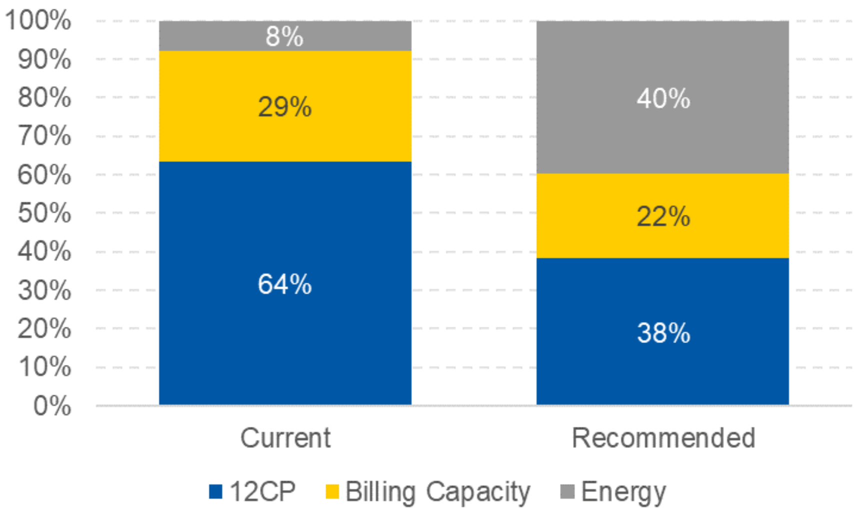
77. In addition to those industrial customers that have already invested in self-supply, other customers are responding to the current transmission tariff by reducing their load at times of 12CP.

## 3.4. The Recommended Tariff and Self-Supply

### 3.4.1. Impact of the change of tariff on customers

78. Our recommended tariff design recovers more costs from energy-based charges, and fewer costs from charges levied on billing capacity and 12CP, as illustrated in Figure 3.1 below.

**Figure 3.1: Recovery of Bulk and Regional Costs Under Current and Recommended Tariff**




*Note: Based on 2020 data provided by the AESO. Excludes POD costs. Source: NERA analysis.*

79. The change in tariff from the current methodology to our recommended methodology affects what customers pay for electricity in different ways depending on how and when they draw power from the grid.

80. In the panel chart below, we illustrate how our recommended tariff affects the amount that four illustrative customers would pay in transmission charges, assuming no other changes in their consumption behaviour.

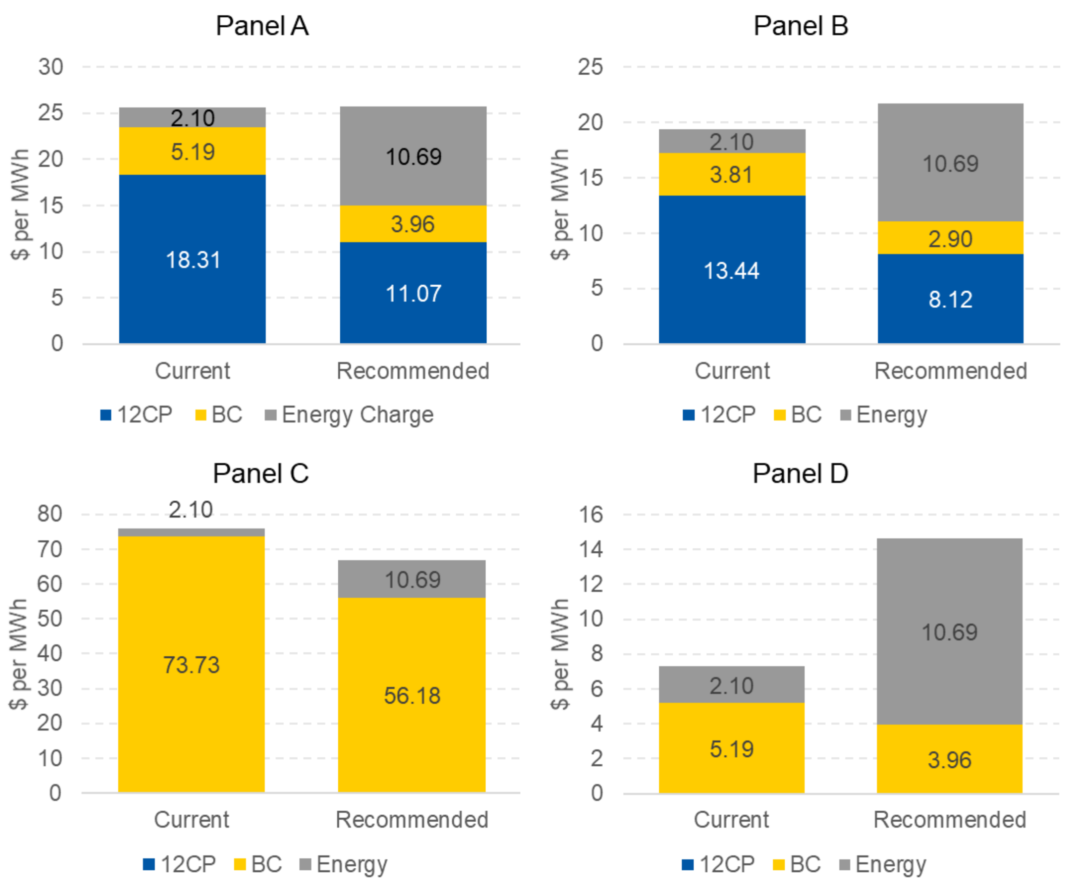
A. In Panel A, we illustrate a baseload industrial customer. We construct its load profile from the assumptions used in the AESO's Delivered Cost of Electricity Report, and assume the customer has peak load of 6.77 megawatts (MW) with an average annual load of 4.97 MW (i.e. a load factor of 73 per cent). We assume the customer draws 6.77 MW of energy during times of coincident peak, and also has contract capacity of 6.77 MW.

B. In Panel B, we illustrate a baseload industrial customer, with similar characteristics to that in Panel A, but with average annual load of 6.77 MW (a load factor of 100 per cent).

C. In Panel C, we illustrate an industrial customer using the grid for back-up. The customer has very low average load of 0.35 MW (a load factor of 5 per cent). However, the customer may draw up to 6.77 MW of load at times when it needs to use the grid for back-up. We assume the customer does not use the grid for back-up during times of coincident peak, as defined by the 12 CP hours.

D. In Panel D, we illustrate an industrial customer with the same characteristics as the industrial customer in Panel A, but which avoids paying charges during the 12 CP hours through load management.

**Figure 3.2: Change in Tariffs for Illustrative Industrial Customers**




*Note: Based on 2020 data. For simplicity, we assume a customers' consumption during coincident peak does not vary across years and therefore the movement to a five-year average 12CP charge does not impact customers charges. Excludes POD Costs. Source: NERA Illustration.*

81. Implementing the classification and functionalization of costs envisaged by our recommended tariff design using data for 2020, our recommended tariff design would recover more costs from energy-based charges than the current tariff. Therefore, transmission charges for customers with high load factors and high energy consumption, such as the customer in Panel B would tend to increase under our recommended tariff. Also, customers which have previously avoided 12 CP hours, such as the customer in Panel D, could see a rise in charges under our recommended tariff, which recovers more costs from energy in all hours and fewer costs from charges levied on 12CP.

82. However, because our recommended tariff recovers fewer costs from the 12CP and contract capacity charges, customers with lower load factors that consume at these

times, such as customers in Panel A and Panel C, tend to have lower charges under our recommended tariff.

83. Our analysis suggests that some customers' incentives to self-supply would increase, while other customers' incentives to self-supply would reduce following our recommended change in the tariff.

84. However, our analysis above assumes customers' consumption behaviour does not change in response to the change in tariff. In reality, our recommended tariff design may incentivise customers to change how and when they use the grid:

A. The reduction in the 12CP charge may reduce customers' incentive to avoid consumption at times of coincident peak, thereby increasing usage of the grid at these times;

B. The reduction in the charge on contracted demand also increases customers' incentive to hold contracted capacity to the grid to use the grid as back-up, which may reduce incentives for grid defection; and

C. The increase in the energy charge may decrease customers' incentive to take energy from the grid across the year.

85. Such changes will tend to be efficient in the long-run, because our recommended tariff is more cost reflective than the current tariff for the reasons explained above and in the Stakeholder Session 5 presentation. The more cost reflective price signal will therefore promote more efficient decisions as to whether to self-supply. However, to help the AESO and stakeholders quantify the likely impact of the change in tariff on self-supply decisions, we have performed quantitative analysis to estimate the likely impact on industrial customers' decisions to self-supply resulting from our recommended tariff.

### 3.4.2. Incentives to self-supply under the current and recommended tariff

86. As explained below in Section 3.4.3, we have considered in detail how the change in tariff will affect all industrial customers' self-supply incentives. However, by way of an example, consider the case of the customer in Panel B above. This customer has a 100 per cent load factor, consuming 6.77 MW in all hours of the year. We assume

this customer is directly connected to the transmission system, thereby incurring only transmission charges and the cost of energy to purchase power from the grid.

87. For the purpose of this illustration, we assume that the customer could choose to self-supply using a baseload gas generator. We adopt the costs of a aeroderivative combustion engine ("ACE") plant with cost assumptions as detailed in the AESO's Cost of New Entrant Analysis.[24] We outline the cost assumptions for this plant in more detail in Appendix A.2.4. Given the customer has a load factor of 100 per cent, we compare the cost per MWh of self-supplying all of its energy with an ACE plant of capacity 6.77 MW relative to purchasing its power from the grid. We assume the customer remains connected to the grid for back-up but does not draw any energy.

88. We illustrate the costs of self-supply relative to purchasing power under the current and our recommended tariff per MWh of consumption across a year in Figure 3.3 below. The figure uses a baseload pool price of $49.39 per MWh, based on the average pool price in 2020.[25]

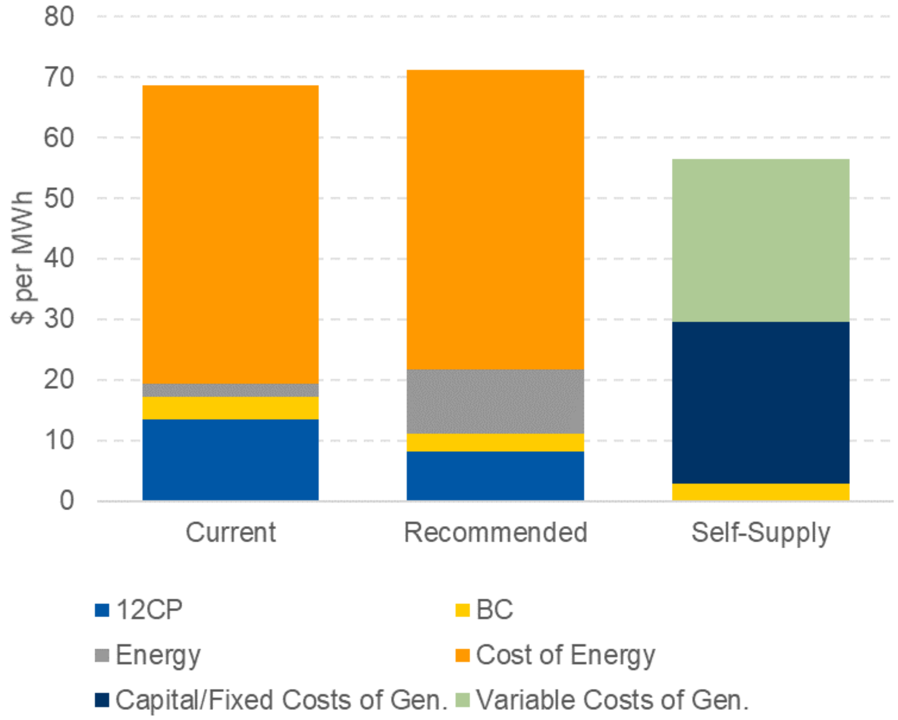
89. Our analysis suggests that the costs of self-supply across the year for the Panel B customer are below the costs of purchasing power from the grid under both the current and recommended transmission tariff designs. This finding corroborates the AESO's Delivered Cost of Electricity Report, see Figure 3.4 below.[26] The AESO identifies, using a different customer load profile and self-supply technology, that the delivered cost of electricity through self-supply (the purple, yellow, and blue bars) is lower for the illustrative, transmission-connected industrial customer than the costs of purchasing energy from the grid under the current tariff (the purple and yellow bars).

[24] Johannes P. Pfeifenberger et al. (4 September 2018), AESO Cost of New Entry Analysis: Combustion Turbines and Combined-Cycle Plants with November 1, 2021 Online Date.

[25] AESO data sourced from its 2020 Q4 Update – Transmission Rate Projection.

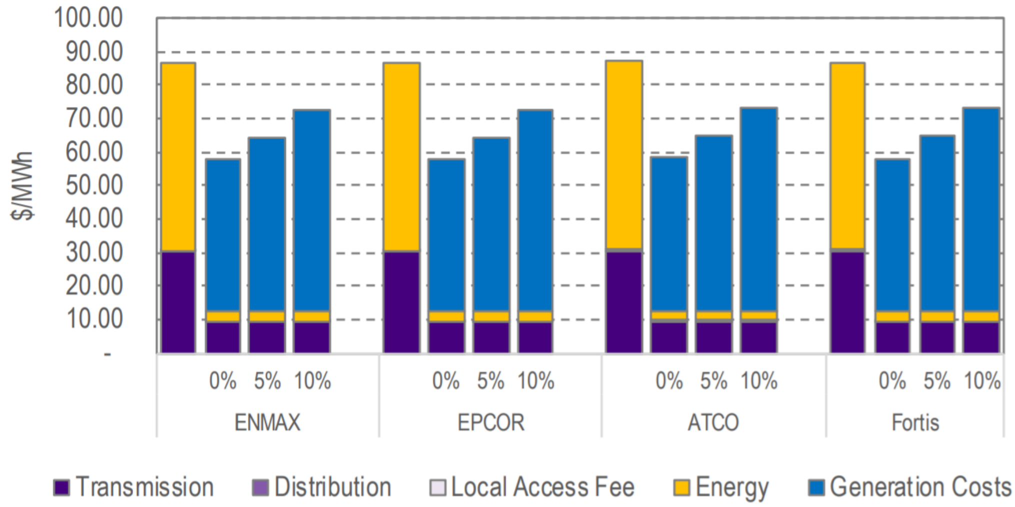
[26] AESO (31 May 2020), Delivered Cost of Electricity Report, Figure 9.5-1.

**Figure 3.3: Illustrative Cost of Self-Supply Relative to Purchasing Power from the Grid Under Current and Recommended Transmission Tariff (2020 C$)**




*Note: 2020 gas price of C$1.92 used as reported by the AER. POD costs not included in transmission tariff. Source: NERA analysis.*

**Figure 3.4: AESO's Delivered Cost of Electricity for an Illustrative Industrial Customer Across Service Territories in 2019**




*Note: The purple and yellow bars in the left-hand column of each service area illustrate the costs of purchasing power from the grid. The three purple, yellow, and blue bars on the right-hand columns of each service area illustrate the costs of self-supplying power at different rates of return. Source: AESO (31 May 2020), Delivered Cost of Electricity Report, Figure 9.5-1.*

90. However, as we discuss in Section 3.3, only 37 per cent of industrial load is currently self-supplied, despite the suggestion from the analysis above that the economics of self-supply is favourable under the current tariff:

A. Industrial customers with different load profiles have different costs of purchasing power from the grid or self-supplying, as compared to the baseload customer used in the example above.

B. Industrials incur additional costs to self-supply beyond the capital and operating costs required to build and operate self-supply generation units. Other costs may include the costs of land (which may not be available at all close to industrial sites), costs of personnel, and the costs/risks associated with additional business complexity or administration. These costs are additional factors not captured in the above analysis which can lead to industrial customers continuing to purchase power from the grid, even if a simple cost comparison suggests it may be cheaper to self-supply.

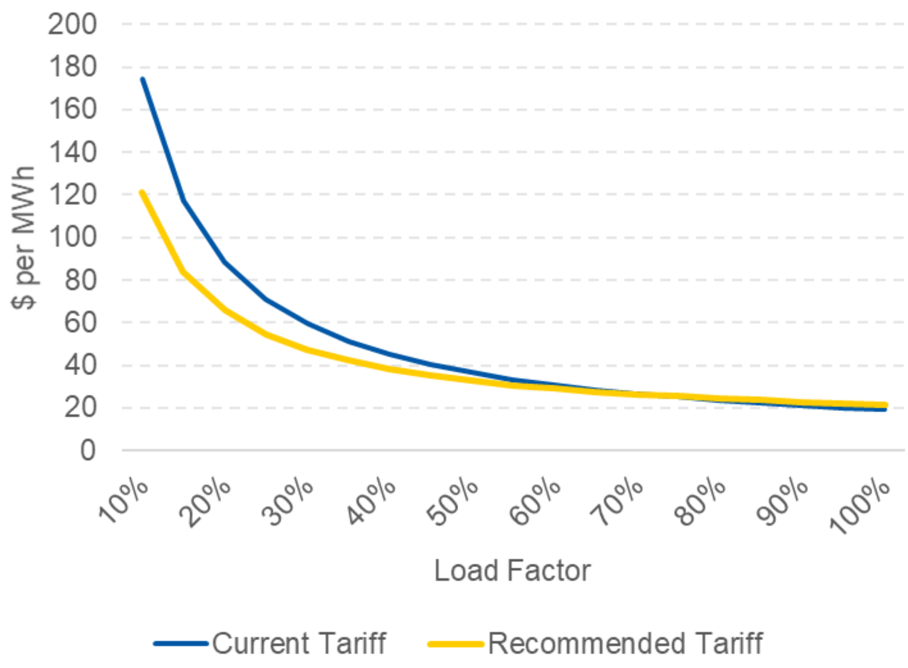
C. On the other hand, the options for customers to self-supply are more diverse than in our analysis above, as customers can choose from an array of technologies to self-supply such as baseload or peaking generation. It is reasonable to assume that customers will choose the least-cost self-supply option across technologies when considering the costs of self-supply compared to purchasing power from the grid.

91. As well as showing that self-supply appears cheaper than purchasing power from the grid, our analysis in Figure 3.3 suggests that the self-supply incentives for customers with a high load factor do not change materially following the change in tariff. Therefore, this illustrative analysis suggests that the increase in costs associated with purchasing power from the grid for a customer with a high load factor is likely to be small.

92. Moreover, for customers with lower load factors like those in Panel A and Panel C, we would expect the customers to face a lower incentive to self-supply, as the cost of purchasing power falls under our recommended tariff relative to the current tariff. In Figure 3.5 below, we illustrate transmission charges for customers with the same

characteristics as the customer in Panel B, with billing capacity and 12CP consumption of 6.77 MW, but with varying load factors. We do not illustrate the costs of purchasing energy from the grid in the Figure. Transmission charges are lower under our recommended tariff for this illustrative customer up to a load factor of between 70 to 75 per cent.

**Figure 3.5: Illustrative Transmission Charges for Illustrative Customers with Varying Load Factors Under Current and Recommended Transmission Tariff (2020 C$)**




*Note: POD Costs Excluded. Source: NERA Illustration.*

93. For customers currently avoiding 12CP, such as in Panel D, it is more difficult to determine the impact of the change in tariff on their incentive to self-supply. Whilst these customers face a lower incentive to self-supply during times of coincident peak under the recommended tariff, they face higher costs of purchasing energy from the grid during times other than coincident peak.

### 3.4.3. Our modelling procedure to estimate the customer response to our recommended tariff

94. In reality, customers' optimal decisions to self-supply are more complicated than the illustrative customer in Figure 3.3 above. Customers with high load factors rarely have 100 per cent load factors, which means their incentives to self-supply depend on cost savings that vary by the hours in which they are consuming power from the grid.

Moreover, because customers take different amounts of energy across hours, it may be optimal for them to install generators that allow them to self-supply all or part of their load, or a combination of types of generators to use in different hours of the year.

95. Therefore, to better assess the potential customer response to the change in tariff we conducted quantitative modelling to analyse how self-supply decisions may change for industrial sites after the introduction of our recommended tariff, which we explain in more detail in Appendix A.

96. Our modelling procedure uses hourly load data provided by the AESO for 133 industrial sites in 2018 and 2019 to assess whether and to what extent it would be economic for each site to self-supply rather than purchase power from the grid across the year, considering both wholesale prices and transmission tariffs. For each customer, we estimate the optimal amount of self-supply under both the current and our recommended tariff to examine how self-supply will change in response to our recommended tariff.

97. However, because our modelling procedure predicts the amount of self-supply based on whether it would be cheaper to self-supply or buy power from the grid, it significantly overstates the tendency for customers to deploy self-supply options. As we discuss in Section 3.1.1, this arises because we do not account for other costs customers face to self-supply that we cannot observe, such as land costs or capital constraints.

98. To address this, we introduce a statistical procedure to estimate how likely customers have been in the past to self-supply, as a function of the potential cost savings a customer could make from self-supplying, based on each customers' characteristics. We assess the performance of our statistical approach by using it to predict existing actual self-supply under the current tariff. We find our approach accurately predicts self-supply (see Appendix A.3.2).

99. We then use our statistical approach to predict actual customer responses to the change in the incentive to self-supply under our recommended tariff.

100. Our analysis focuses on the likely customer response to the increase in the energy charge under our recommended tariff relative to the current tariff. We do not consider

customer response to the decrease in 12CP charges under our recommended tariff relative to the current tariff, except through the extent to which it changes their decisions to optimally self-supply. In other words, we do not consider how decreases in the 12CP charge under our recommended tariff may increase customers' gross load during times of 12CP, and therefore our analysis is conservative with respect to self-supply by customers during times of coincident peak.

101. Overall, our approach predicts an extremely limited increase in self-supply by industrial customers under our recommended tariff. We estimate that self-supply could increase under our recommended tariff by up to 2,801 GWh which is equivalent to 4.69 per cent of the total metered energy billing determinant, used to calculate the transmission energy charge, in 2019.

102. As we explain in Appendix A, our estimate of customer response is a total effect that includes any dynamic responses by customers to self-supply decisions of other customers. This "dynamic response" accounts for the effect of higher self-supply pushing up tariffs levied on the remaining demand, which may increase further the incentives customers have to self-supply.

103. It is also equivalent to a total cost shift of C$ 29.92 million (in real 2019 terms) from self-supply customers to other customers, which is approximately 1.9 per cent of the total revenue requirement for B&R costs in 2019.

104. Therefore, whilst, in Section 3.1.2, we identified the possibility that a tariff set to recover historical costs will cause customers to self-supply, despite sending efficient price signals over the costs of providing transmission in the long run. Our modelling approach suggests that under current system conditions, any reduction in energy demand from the transmission system resulting from our recommended tariff design is likely to be extremely limited.

## 3.5. Future Trends in the Economics of Self-Supply

105. While the impact of our recommended tariff on self-supply is likely to be limited given the current costs of self-supply, the economic case for self-supply in Alberta is likely to worsen in the next decade.

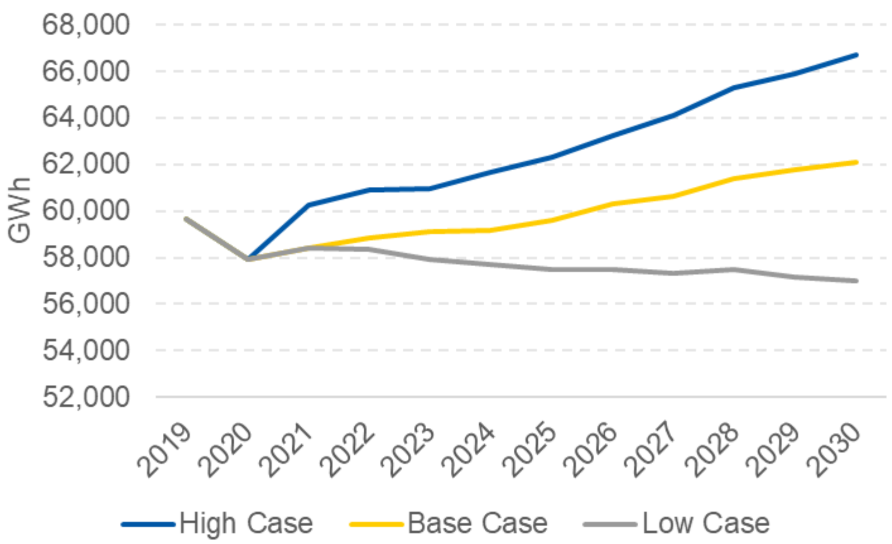
106. As we discuss in Section 3.1.1, customers' decisions to self-supply will necessarily be forward-looking because the upfront capital costs of investing in generators are offset by savings relative to purchasing power from the grid over future years (i.e. over the useful life of the generator). Therefore, not only do the current incentives to self-supply affect a customer's decision to self-supply, but also their expectations regarding future cost savings relative to purchasing power from the grid.

107. We identify two potential drivers of the future costs that customers would incur (and benefits they would obtain) by self-supplying power rather than purchasing it from the grid: future trends in transmission charges and future trends in the variable costs of self-supply.

### 3.5.1. Future trends in transmission charges

108. The AESO's low growth sensitivity projection of demand transmission service load in Alberta shows declining forecast energy consumption through to 2030, as shown in Figure 3.6. We focus on the low growth scenario to ensure we do not understate the potential for transmission tariffs to rise, and therefore avoid understating customers' incentive to self-supply.

**Figure 3.6: AESO's Forecast of Total Energy Consumption**




*Source: NERA Analysis of AESO Data.*[27]

[27] AESO data sourced from its 2020 Q4 Update – Transmission Rate Projection.

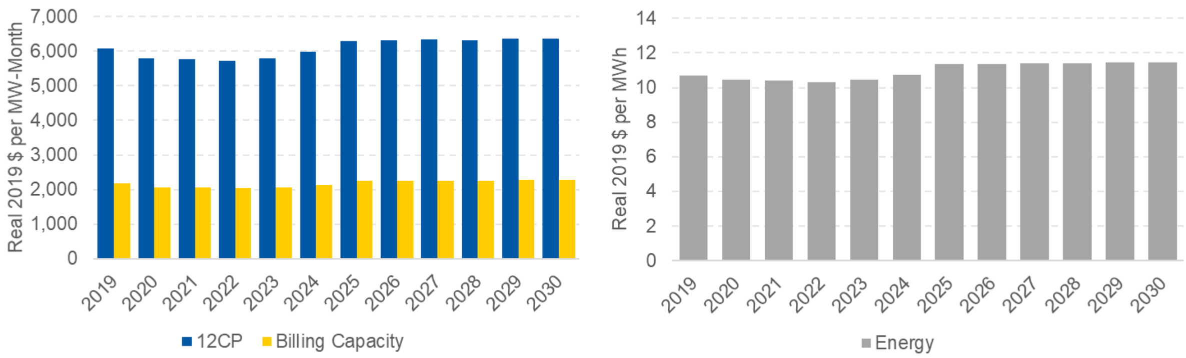
109. Reductions in demand which are coupled with the same revenue requirement can lead to a rise in transmission charges in order to ensure cost recovery. Using the low growth sensitivity forecast, the AESO's forecast revenue requirement, and the same percentage recovery of costs by billing determinant as 2020, we forecast transmission charges under our recommended tariff design.[28] Our forecast is an approximation because, amongst other reasons:

A. We assume the same revenue requirement forecast under the baseline demand projection is appropriate for the low demand forecast projection.

B. We do not account for changes in the classification of costs in our methodology in light of the changing use of the system over the forecast horizon.

110. We illustrate our forecast of transmission charges (in real 2019 C$) in Figure 3.7 below.

**Figure 3.7: Forecast Transmission Charges Under Our Recommended Tariff in the AESO's Low Energy Growth Scenario**




*Note: Source: NERA analysis of AESO data. Inflation forecast from 2020 taken unchanged from the AESO's Rate Projection, and originally sourced from Statistics Canada Table 326-0020, Data Vector V41692327, and Conference Board of Canada Data Vector RPCPIA.*

111. Our forecast suggests that transmission charges will rise slightly as energy consumption falls over the period to 2030. In absence of a reduction in other costs of purchasing power from the grid, such as the pool price which may fall with lower energy consumption, higher transmission charges will increase the costs of purchasing

28 We also construct a low growth sensitivity forecast of coincident metered demand that forms the charging basis of the 12CP billing determinant, and billing capacity. To do so, we examine the ratio of total annual energy consumption and coincident metered demand and billing capacity in the AESO's central projection. We then apply the same ratio to forecast the coincident metered demand billing determinant and billing capacity billing determinant from the low growth forecast of energy consumption.

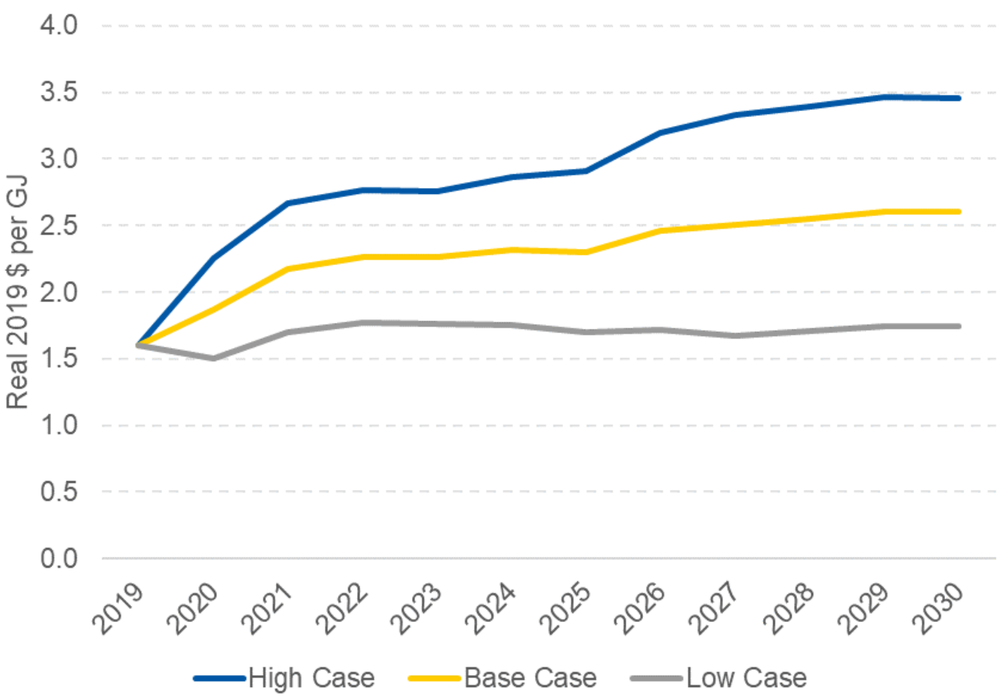
power from the grid for some customers thereby, in theory, increasing the cost savings associated with self-supply.

### 3.5.2. Future trends in the fuel and carbon costs of self-supply

112. However, the costs of self-supply are also likely to change over this timeframe. Higher costs of self-supply reduce the cost savings associated with self-supply relative to purchasing power from the grid. We identify two key drivers of the costs of generating power to self-supply that are particularly likely to change in the coming years: fuel costs and the carbon price.

113. We have examined the forecast annual average AECO-C natural gas price from 2019 to 2030 as published by the Alberta Energy Regulator (AER).[29] We show the forecast in Figure 3.8 below. As shown, the gas price is forecast to rise in real terms relative to 2021.

**Figure 3.8: AER's Forecast AECO-C Natural Gas Price**

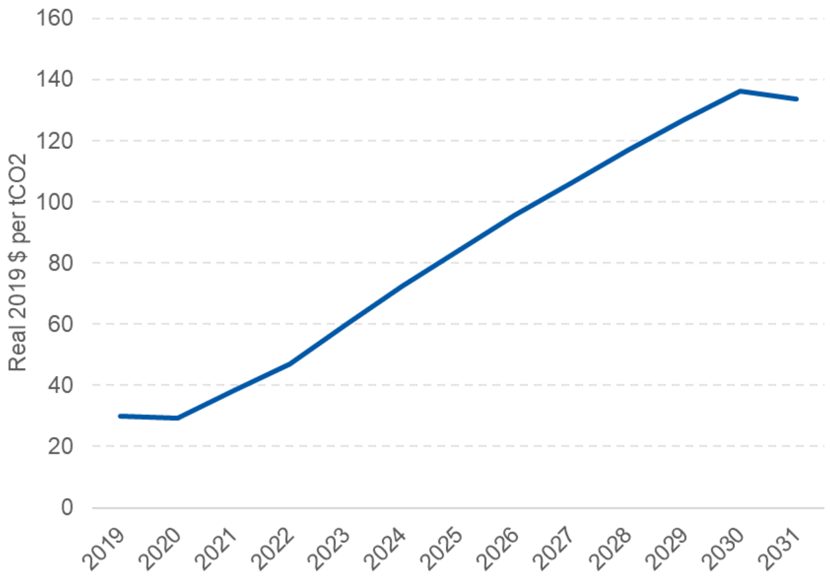



*Source: NERA analysis of AER data.*

29 Alberta Energy Regulators Forecast of AECO-C gas prices updated June 2020 and accessed here: https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st98/prices-and-capital-expenditure/natural-gas-prices/aeco-c-price. Last Accessed 12 May 2021.

114. We also examine forecast annual carbon prices. The Federal Government implemented a federal carbon tax through the Greenhouse Gas Pollution Pricing Act in 2018.[30] We understand that under this regime the carbon tax, which is currently \$30 per tCO2, is intended to rise to \$170 per tCO2 in 2030, with a \$10 per tCO2 rise in 2021 and 2022, and a \$15 per tCO2 rise per year starting from 2023. We illustrate this rise (in real 2019 C\$) in Figure 3.9 below.

**Figure 3.9: Forecast Federal Carbon Tax**




*Source: NERA analysis.*

115. The impact of future growth in gas and carbon prices on incentives to self-supply depends on how the costs of self-supply change *relative* to the pool price. Higher carbon and gas prices will increase the wholesale price for power, as generators incur higher costs to produce power. Higher pool prices increase the costs of purchasing power from the grid, and thereby increase the cost savings associated with self-supply. On the other hand, rising gas prices and carbon prices will also result in higher costs of self-supply using gas-based generation, decreasing the cost savings associated with self-supply relative to purchasing power from the grid.

116. To the extent that gas-fired generators are the marginal source of in-merit energy in the wholesale market, the relative efficiency of grid-connected and gas generators

30 *Greenhouse Gas Pollution Pricing Act*, SC 2018, c 12, s 186.

used to self-supply will drive whether changes in the carbon or gas price will impact the pool price more or less than the costs of self-supply. Customers installing gas generators to self-supply will likely not require, or be able to install, generators of the scale used to generate power for the grid. The smaller generators used to self-supply are likely to be less efficient than the larger generators used to generate power for the grid. Using more inefficient generators means that self-supplying customers will need to use more gas to generate energy relative to grid-serving generators, resulting in higher gas costs and carbon costs per unit of energy generated.

117. To examine this, we compare the heat rates of representative plants that customers could use to self-supply with the heat rates of representative gas plants used to generate power for the system.[31] More specifically, we compare the heat rates of a combined cycle gas plant (CCGT) that we assume would be used to generate power for the grid with the heat rates of an ACE plant and a gas-fired reciprocating internal combustion engine ("RICE") which could be used to self-supply. We detail the assumptions and sources of costs of each plant in Appendix A.2.4. We compare the heat rates in Table 3.1 below.

**Table 3.1: Comparison of Heat Rates Across System and Self-Supply Plant**

| | | CCGT | ACE | RICE |
|---|---|---|---|---|
| **Heat Rate** | GJ per MWh | 6.72 | 9.68 | 10.50 |
| *Additional Heat Rate Relative to CCGT* | *GJ per MWh* | | *2.96* | *3.78* |

*Note: Heat Rates Treated as Net HHV, underlying sources do not specify. Source: NERA Analysis.*

118. As the table shows, both ACE and RICE plants require more fuel relative to a CCGT to produce one MWh of electricity. We convert the additional energy requirement per MWh shown in the table to an additional gas requirement per MWh, and then an additional gas cost per MWh using the AER Low Case. We select the Low Case to ensure we do not understate the economic case for self-supply.

[31] The heat rate of a plant specifies how much gas is required to generate a unit of power. Whilst peaking, simple cycle gas plants also generate power for the system, they do so in fewer hours of the year than baseload, combined cycle gas plants which is why we consider baseload plants in our analysis.

119. Given the ACE and RICE plants require more gas to produce one MWh, self-suppliers will also incur more in carbon costs to run the plant. To calculate the additional carbon costs, we assume the ACE and RICE plants are subject to the federal carbon tax, and are also part of Alberta's Technology Innovation and Emissions Reduction ("TIER") regulation, meaning that they only pay carbon taxes on emissions above the "best in gas" standard. We assume the CCGT in our analysis has emissions that meet the best in gas standard.[32] Therefore, because we are examining the carbon costs associated with the *incremental* costs incurred by self-supply technologies relative to a best in gas CCGT, we assume all of the additional gas used by ACE or RICE technologies relative to CCGT will be subject to carbon taxes.

120. To calculate the additional carbon emissions associated with the additional gas required by self-supply technologies, we calculate the extra emissions associated with the higher gas requirement for ACE and RICE technologies relative to CCGT plants, as shown in Table 3.2 below. We then calculate the carbon costs for alternative technologies by multiplying this extra volume of emissions by the carbon price shown in Figure 3.9 above.

**Table 3.2: Additional Emissions Associated with Self-Supply**

| | Units | **System CCGT** | **ACE** | **RICE** |
|---|---|---|---|---|
| **Heat Rate (Net HHV)** | GJ per MWh | 6.72 | 9.68 | 10.50 |
| **Emissions Rate** | t per MWh | 0.338 | 0.486 | 0.527 |
| | | | | |
| **Additional Gas Use Per MWh** | GJ per MWh | | 2.96 | 3.78 |
| **Additional Emissions Per MWh** | t per MWh | | 0.1485 | 0.1898 |

**Note: As we discuss in Appendix A.2.4, we recalculate the emissions rate for all plants using (i) tCO2/therm = 0.0053[33] (ii) Btu/therm = 100,000;[34] therm/GJ = 0.105506.[35] Source: NERA Analysis.*

32 Whilst we recognise that the current "best in gas" standard corresponds to an emissions rate of 0.37 CO2t per MWh, we also understand that the threshold rate should fall over time. Therefore, we assume self-suppliers pay carbon taxes on all fuel use above the emissions rate of the system CCGT of 0.338 CO2t per MWh from the EIA in our analysis.

33 EIA, Greenhouse Gases Equivalencies Calculator - Calculations and References, Last Accessed 17 May 2021, Link: https://www.epa.gov/energy/greenhouse-gases-equivalencies-calculator-calculations-and-references.

34 EIA, FAQs, Last Accessed 17 May 2021, Link: https://www.eia.gov/tools/faqs/faq.php?id=45&t=8

35 EIA, Energy Conversion Calculators – Natural Gas, Last Accessed 17 May 2021, Link: https://www.eia.gov/energyexplained/units-and-calculators/energy-conversion-calculators.php

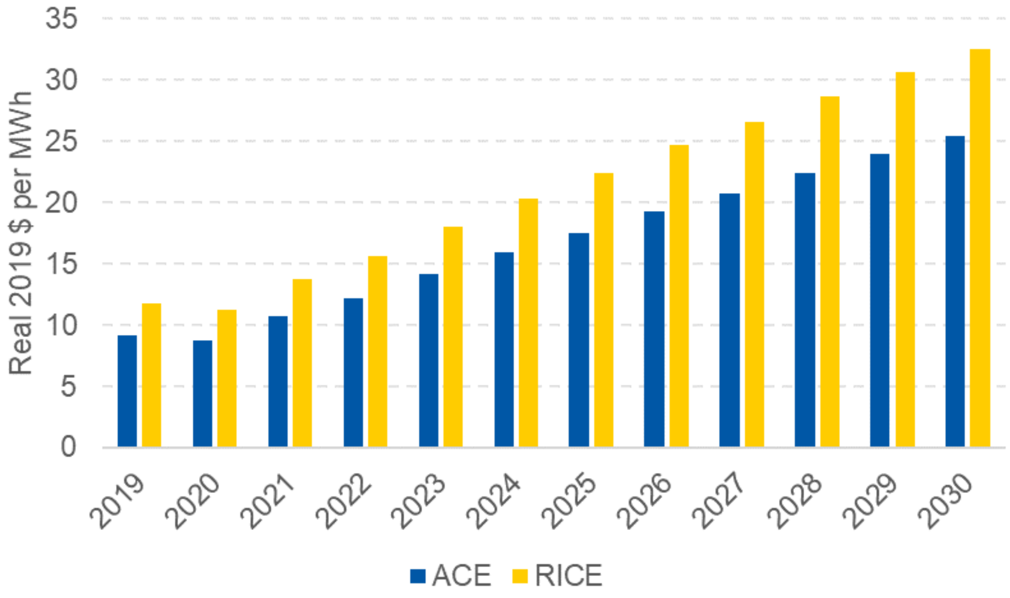
121. We illustrate the additional variable costs of self-supply using the ACE and RICE generator relative to a system CCGT in Figure 3.10 below. The figure shows the additional costs to generate one MWh using self-supply technologies rather than purchasing energy generated using a CCGT, supplied to the customer via the transmission grid.

122. The figure shows that we expect rising carbon and gas costs will make self-supply technologies more expensive over time, when compared to the cost of purchasing power from the grid:

A. By 2030, the fuel and carbon costs of producing a MWh using an ACE or RICE generator will be $25.40 or $32.47 per MWh (in real 2019 terms) more expensive, respectively, than producing that MWh using grid technology, relative to around $10 per MWh today.

B. Therefore, upward pressure on fuel and carbon prices is expected to reduce the incentive to self-supply.

**Figure 3.10: Forecast Additional Fuel and Carbon Costs of Self-Supply Relative to CCGT Technology**




*Source: NERA analysis.*

### 3.5.3. Future trends in the economics of self-supply

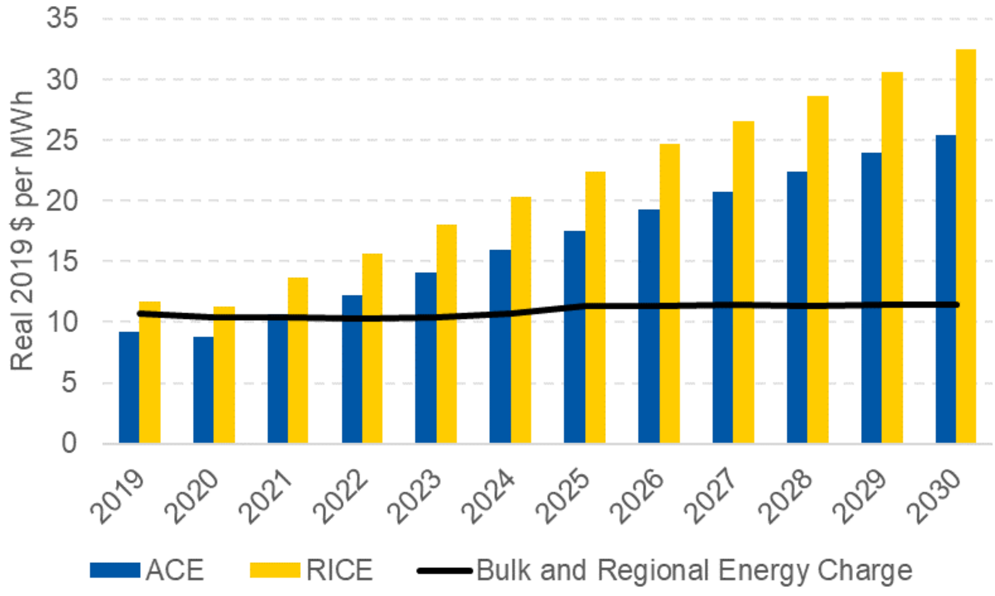
123. We illustrate in Figure 3.11 below the two drivers of future trends in the economics of self-supply:

A. Changes to the energy component of the transmission tariff under our recommended tariff structure,[36] and assuming the AESO's low demand growth scenario (see also Figure 3.7); and

B. The additional fuel and carbon costs of self-supply, driven by changes in gas and carbon prices (see also Figure 3.10).

124. The figure illustrates the additional costs incurred to self-supply one MWh using self-supply technology instead of purchasing that power from the grid (where it is generated by a CCGT), compared to the energy component of the transmission tariff.

**Figure 3.11: Future Trends in the Economics of Self-Supply**




*Source: NERA analysis.*

125. While we show above and in Appendix A that in current cost conditions, we estimate that our recommended tariff will not materially increase self-supply, the projection in Figure 3.11 shows that the economics of self-supply for industrial customers is also

[36] We focus on the energy charge of the transmission tariff because it is the component that increases in our recommended tariff relative to the current tariff.

set to worsen in the coming years due to the effects of carbon pricing. In other words, even though we estimate that our recommended change in the tariff will have a small effect on self-supply volumes, the incentives to self-supply are set to worsen materially in the coming years which means we expect an increase in energy charges will not cause significant reductions in the volume of energy supplied from the grid.

# 4. Summary

126. Some electricity industry participants (both in Alberta and globally) may have legitimate concerns about the risks of grid bypass and grid defection, especially in relation to transmission and distribution companies that already recover all (or the majority of) their costs from tariffs levied on energy consumption.

127. A proportionate response to these concerns is to adjust tariffs to ensure they have a cost structure that reflects the cost structure of the service in question as closely as possible, which we strive to do through our recommended tariff design.

128. Designing a tariff with the intention of minimising self-supply would be a disproportionate response. In fact, customers should be encouraged to self-supply when the costs they incur to do so are below the costs of supplying them from the grid. Self-supply decisions in response to cost reflective tariffs promote efficiency in the overall supply of electricity, and will tend to reduce the costs faced by the customers who purchase energy from the grid.

129. In the AESO's case, it is currently charging for the majority of its costs through a 12CP charge, the extent to which is not justified on grounds of cost causation as explained in the Stakeholder Session 5 presentation. The current tariff is therefore promoting *inefficient* self-supply decisions aiming to avoid 12CP charges. By contrast, our recommended tariff better reflects the dual purposes of transmission in Alberta: to meet peak demand and accommodate the flow of in-merit energy.

130. Therefore, customer response to the change in transmission tariff through different self-supply decisions will improve efficiency because the new transmission tariff is more cost reflective. However, even if a tariff is designed to reflect the cost structure of the transmission system, and therefore promote efficient decisions to use the grid or self-supply in the long-term, there remains a possibility that a tariff set to recover historical costs will cause customers to inefficiently self-supply in the short-term in cases where those customers make lower contributions to historical costs.

131. We therefore estimate customer response to our recommended tariff using a modelling procedure. We estimate that self-supply could increase under our recommended tariff by up to 2,801 GWh which is equivalent to a shift in costs from

self-supplying customers to other customers of approximately 1.90 per cent of the total revenue requirement for bulk and regional costs in 2019. Our estimate of customer response is a total effect that includes any dynamic responses by customers to self-supply decisions of other customers.

132. Our estimate of customer response ignores the potential for customers to increase purchasing of power from the grid during times of coincident peak in response to lower 12CP charges in our recommended tariff relative to the current tariff.

133. Hence, we predict an extremely limited increase in self-supply by industrial customers under our recommended tariff, and any change in customers' self-supply decisions that does arise will tend to result in more efficient patterns of electricity usage than under the current methodology.

# Appendix A. Estimating Customer Response to Our Recommended Tariff

## A.1. Overview of Our Approach

134. As we discuss in Section 3.4, our analysis of customers' decisions to self-supply using illustrative consumption profiles simplifies the self-supply decision. Customers' actual self-supply decisions depend on how and when they use electricity, which for most customers vary across hours of the year (and is rarely at a 100 per cent load factor as we assume for the customer in Panel B in Figure 3.2).

135. Customers consider different self-supply technologies, and different ways of optimally self-supplying using those technologies, depending on their consumption profile. For instance, as we discuss in Paragraph 27, customers can consider peaking generators for use during hours of the year when the costs of purchasing power from the grid are highest, or baseload generators for use during a larger number of hours of the year.

136. The choice of self-supply technology depends on the individual circumstances of the customer, and balances the fixed and variable costs of operating the self-supply technology with the avoided costs of purchasing power from the grid, which vary across hours of the year with the customers' consumption profile.

137. In order to better assess how customers may respond to our recommended transmission tariff, we model the optimal self-supply decisions for industrial sites in Alberta. Our approach is formed of three steps:

A. ***Step 1:*** We construct a model that estimates the optimal self-supply decisions for industrial sites across Alberta, based on a simple comparison of the costs of purchasing power from the grid and self-generation costs. The model allows different customers (industrial sites) to use different self-supply technologies, and operate those technologies in different ways to optimise their decision to self-supply or purchase power from the grid. By performing this optimization for each customer, we estimate the optimal amount of self-supply across Alberta under the current and our recommended tariff.

B. ***Step 2:*** However, this optimisation model overstates the actual self-supply for customers because we do not model other costs associated with self-supply such as costs and risks associated with business complexity or financing. Consequently, actual self-supply by customers will be lower than the optimal self-supply identified by the model in Step 1, or "incentive to self-supply", that we model. To estimate how customers' actual self-supply decisions will be affected by a change in the transmission tariff, we estimate a regression equation to capture how likely customers are to self-supply, given the economic incentive to self-supply identified in Step 1. This regression also controls for customers' characteristics such as size, location, and industry.

C. ***Step 3:*** We then use our regression to predict customers' response to the change in incentive to self-supply under our recommended tariff.

138. In this Appendix, we detail our modelling approach and results from each of the above steps in more detail.

## A.2. Step 1: Modelling the Optimal Self-Supply Decision for Customers

139. We examine the optimal self-supply decision for customers using site-level, hourly gross load data in 2018 and 2019.[37] Of the 564 sites for which we have load data, 133 are sites with only load from industrial customers. We use the 133 industrial-only sites in our analysis.

A. We assume that there is a single industrial customer at each industrial-only site that is responsible for the entire load at that site.[38]

B. Sites which are not industrial-only, are often constituted by a mixture of industrial, residential, commercial, or other customers. We are unable to use these sites as we cannot distinguish the profile of consumption belonging to industrial customers from residential customers.

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37 By gross load, we mean total consumption of power at the site, irrespective of whether that power is sourced from the grid or through self-supply. We use net load to refer to the site's purchase of power from the grid, in other words, its gross load less any self-supply it chooses to undertake. We rely on AESO site-level load data in our analysis.

38 Our assumption likely leads us to overstate self-supply, assuming a single industrial customer at each site means self-supply may be more economic than if the site comprised multiple, smaller customers.

140. For each industrial customer (site), we calculate both the costs of purchasing power from the grid without self-supplying and the customers' optimal self-supply decision in 2018 and 2019. To perform these calculations, we use the procedure described below.

### A.2.1. We group hours of the year to reduce the computational requirements of the model

141. In order to reduce the computational requirements of the model, we group similar hours of the year together using a Price Duration Curve approach. In total we define 53 groups of hours that are similar in terms of the costs that would be incurred to purchase power from the grid.

142. We define separate groups of hours for 2018 and 2019 based on the pool price in 2018 and 2019 respectively. More specifically:

A. The first 51 groups of hours are defined by percentiles of the distribution of hourly pool prices observed during the year in question.[39]

B. The 52nd group of hours is defined to capture rare incidences of scarcity pricing in the pool, where the pool price equals the price cap of $1000 per MWh. If we did not define the 52nd group of hours in this way, the average price of the 51st group of hours would be high as it would be influenced by these rare occurrences of scarcity pricing, which would distort our estimate of the self-supply decision in the hours in the 51st bucket.

C. The last group of hours is defined to contain 12CP hours only.[40] We separate 12CP hours to allow customers' self-supply decisions to change in 12CP hours in order to avoid the 12CP charge. Our model likely overstates customer response, because we assume that all customers can perfectly predict hours of 12CP.

143. Having grouped the hours of the year in this way, we calculate the average pool price and each customers' average gross demand in each group of hours. The average pool

[39] This corresponds to prices every 2nd percentile, with an additional price group to capture prices close to zero.

[40] Whilst in reality, 12CP is defined by a fifteen-minute interval, we are restricted by the data to look at hours of 12CP. We levy the 12CP charge on customer consumption during the hour of 12CP.

price and average demand during each group of hours defines a "representative hour" that applies to all hours within this group.

144. The tables below show the Price Duration Curves used by the model to characterise the costs of purchasing electricity from the wholesale market in 2018 and 2019.

**Table A.1: Price Duration Curve (2018)**

| Group | Number of Hours | Min Price In Group ($/MWh) | Average Pool Price | Transmission Tariff ($/MWh) *Current Design* | *Recommended Design* |
|---|---|---|---|---|---|
| 1 | 171 | 0.00 | 14.52 | 2.04 | 8.80 |
| 2 | 172 | 20.50 | 23.13 | 2.04 | 8.80 |
| 3 | 172 | 24.86 | 25.53 | 2.04 | 8.80 |
| 4 | 166 | 26.20 | 26.68 | 2.04 | 8.80 |
| 5 | 157 | 26.99 | 27.08 | 2.04 | 8.80 |
| 6 | 131 | 27.15 | 27.16 | 2.04 | 8.80 |
| 7 | 0 | 27.18 | | 2.04 | 8.80 |
| 8 | 294 | 27.18 | 27.18 | 2.04 | 8.80 |
| 9 | 283 | 27.19 | 27.26 | 2.04 | 8.80 |
| 10 | 170 | 27.62 | 28.06 | 2.04 | 8.80 |
| 11 | 173 | 28.51 | 29.11 | 2.04 | 8.80 |
| 12 | 172 | 29.64 | 30.12 | 2.04 | 8.80 |
| 13 | 169 | 30.57 | 30.95 | 2.04 | 8.80 |
| 14 | 173 | 31.26 | 31.47 | 2.04 | 8.80 |
| 15 | 124 | 31.64 | 31.70 | 2.04 | 8.80 |
| 16 | 0 | 31.74 | | 2.04 | 8.80 |
| 17 | 392 | 31.74 | 31.74 | 2.04 | 8.80 |
| 18 | 0 | 31.75 | | 2.04 | 8.80 |
| 19 | 0 | 31.75 | | 2.04 | 8.80 |
| 20 | 509 | 31.75 | 31.81 | 2.04 | 8.80 |
| 21 | 177 | 32.14 | 32.33 | 2.04 | 8.80 |
| 22 | 174 | 32.54 | 32.70 | 2.04 | 8.80 |
| 23 | 163 | 32.86 | 32.98 | 2.04 | 8.80 |
| 24 | 173 | 33.08 | 33.16 | 2.04 | 8.80 |
| 25 | 44 | 33.24 | 33.24 | 2.04 | 8.80 |
| 26 | 0 | 33.25 | | 2.04 | 8.80 |
| 27 | 401 | 33.25 | 33.25 | 2.04 | 8.80 |
| 28 | 0 | 33.26 | | 2.04 | 8.80 |
| 29 | 0 | 33.26 | | 2.04 | 8.80 |
| 30 | 593 | 33.26 | 33.27 | 2.04 | 8.80 |
| 31 | 171 | 33.44 | 33.69 | 2.04 | 8.80 |
| 32 | 144 | 33.96 | 34.24 | 2.04 | 8.80 |
| 33 | 199 | 34.54 | 34.55 | 2.04 | 8.80 |
| 34 | 172 | 34.65 | 35.15 | 2.04 | 8.80 |
| 35 | 103 | 35.74 | 36.11 | 2.04 | 8.80 |
| 36 | 241 | 36.43 | 36.75 | 2.04 | 8.80 |
| 37 | 173 | 37.69 | 38.63 | 2.04 | 8.80 |
| 38 | 170 | 39.60 | 40.48 | 2.04 | 8.80 |
| 39 | 169 | 41.37 | 42.16 | 2.04 | 8.80 |
| 40 | 176 | 42.96 | 43.78 | 2.04 | 8.80 |
| 41 | 172 | 44.60 | 45.25 | 2.04 | 8.80 |
| 42 | 171 | 45.90 | 46.05 | 2.04 | 8.80 |
| 43 | 172 | 46.28 | 47.59 | 2.04 | 8.80 |
| 44 | 172 | 48.93 | 50.39 | 2.04 | 8.80 |
| 45 | 172 | 51.94 | 53.82 | 2.04 | 8.80 |
| 46 | 172 | 56.38 | 59.59 | 2.04 | 8.80 |
| 47 | 171 | 63.60 | 68.45 | 2.04 | 8.80 |
| 48 | 172 | 72.77 | 78.74 | 2.04 | 8.80 |
| 49 | 172 | 85.97 | 93.82 | 2.04 | 8.80 |
| 50 | 172 | 106.98 | 165.88 | 2.04 | 8.80 |
| 51 | 155 | 271.98 | 605.73 | 2.04 | 8.80 |
| 52 | 4 | 1,000 | 1,000 | 2.04 | 8.80 |
| 12CP | 12 | | | 10,179 | 5,102 |

*Note: Billing capacity charge not shown in transmission tariff. Source: NERA Analysis of AESO Data. Note: some "groups" appear to have zero hours because pool prices are only specified to 2 decimal places, so hours are allocated to a single group where two or more groups have identical prices.*

## Table A.2: Price Duration Curve (2019)

| Group | Number of Hours | Min Price In Group ($/MWh) | Average Pool Price | Transmission Tariff ($/MWh) Current Design | Recommended Design |
|---|---|---|---|---|---|
| 1 | 171 | 0.00 | 18.80 | 2.13 | 10.68 |
| 2 | 171 | 23.28 | 24.49 | 2.13 | 10.68 |
| 3 | 173 | 25.56 | 26.32 | 2.13 | 10.68 |
| 4 | 172 | 27.02 | 27.44 | 2.13 | 10.68 |
| 5 | 171 | 27.94 | 28.15 | 2.13 | 10.68 |
| 6 | 136 | 28.34 | 28.43 | 2.13 | 10.68 |
| 7 | 207 | 28.47 | 28.52 | 2.13 | 10.68 |
| 8 | 173 | 28.62 | 28.70 | 2.13 | 10.68 |
| 9 | 172 | 28.81 | 28.93 | 2.13 | 10.68 |
| 10 | 171 | 29.06 | 29.36 | 2.13 | 10.68 |
| 11 | 168 | 29.65 | 29.91 | 2.13 | 10.68 |
| 12 | 176 | 30.11 | 30.51 | 2.13 | 10.68 |
| 13 | 171 | 30.93 | 31.25 | 2.13 | 10.68 |
| 14 | 172 | 31.60 | 31.85 | 2.13 | 10.68 |
| 15 | 167 | 32.03 | 32.22 | 2.13 | 10.68 |
| 16 | 175 | 32.42 | 32.53 | 2.13 | 10.68 |
| 17 | 161 | 32.59 | 32.60 | 2.13 | 10.68 |
| 18 | 147 | 32.65 | 32.71 | 2.13 | 10.68 |
| 19 | 204 | 32.78 | 32.79 | 2.13 | 10.68 |
| 20 | 175 | 32.85 | 32.91 | 2.13 | 10.68 |
| 21 | 154 | 32.97 | 33.00 | 2.13 | 10.68 |
| 22 | 179 | 33.05 | 33.10 | 2.13 | 10.68 |
| 23 | 92 | 33.15 | 33.18 | 2.13 | 10.68 |
| 24 | 115 | 33.22 | 33.22 | 2.13 | 10.68 |
| 25 | 317 | 33.23 | 33.30 | 2.13 | 10.68 |
| 26 | 164 | 33.47 | 33.50 | 2.13 | 10.68 |

| Group | Number of Hours | Min Price In Group ($/MWh) | Average Pool Price | Transmission Tariff ($/MWh) Current Design | Recommended Design |
|---|---|---|---|---|---|
| 27 | 183 | 33.54 | 33.59 | 2.13 | 10.68 |
| 28 | 171 | 33.76 | 33.88 | 2.13 | 10.68 |
| 29 | 172 | 34.03 | 34.28 | 2.13 | 10.68 |
| 30 | 173 | 34.53 | 34.80 | 2.13 | 10.68 |
| 31 | 172 | 34.93 | 35.13 | 2.13 | 10.68 |
| 32 | 168 | 35.51 | 35.98 | 2.13 | 10.68 |
| 33 | 174 | 36.50 | 36.95 | 2.13 | 10.68 |
| 34 | 173 | 37.53 | 38.17 | 2.13 | 10.68 |
| 35 | 172 | 38.79 | 39.43 | 2.13 | 10.68 |
| 36 | 172 | 40.12 | 40.81 | 2.13 | 10.68 |
| 37 | 170 | 41.56 | 42.40 | 2.13 | 10.68 |
| 38 | 172 | 43.26 | 44.11 | 2.13 | 10.68 |
| 39 | 172 | 44.92 | 45.69 | 2.13 | 10.68 |
| 40 | 173 | 46.58 | 47.68 | 2.13 | 10.68 |
| 41 | 172 | 48.72 | 49.94 | 2.13 | 10.68 |
| 42 | 171 | 51.09 | 52.38 | 2.13 | 10.68 |
| 43 | 172 | 53.57 | 54.96 | 2.13 | 10.68 |
| 44 | 172 | 56.60 | 58.88 | 2.13 | 10.68 |
| 45 | 172 | 61.20 | 64.18 | 2.13 | 10.68 |
| 46 | 172 | 67.13 | 70.83 | 2.13 | 10.68 |
| 47 | 171 | 74.99 | 79.41 | 2.13 | 10.68 |
| 48 | 172 | 84.37 | 88.91 | 2.13 | 10.68 |
| 49 | 172 | 93.36 | 110.14 | 2.13 | 10.68 |
| 50 | 172 | 143.11 | 226.92 | 2.13 | 10.68 |
| 51 | 158 | 346.08 | 642.24 | 2.13 | 10.68 |
| 52 | 1 | 1,000 | 1,000 | 2.13 | 10.68 |
| 12CP | 12 | | | 10,526 | 6,075 |

*Note: Billing capacity charge not shown in transmission tariff. Source: NERA Analysis of AESO Data. Note: some "groups" appear to have zero hours because pool prices are only specified to 2 decimal places, so hours are allocated to a single group where two or more groups have identical prices.*

145. The Price Duration Curves above use historical hourly pool prices from 2018 and 2019.[41] They also use actual bulk and regional transmission charges in 2018 and 2019 to calculate transmission tariffs under the current tariff design.

146. We calculate transmission costs under our recommended tariff design using the approach described in the Stakeholder Session 5 presentation, using historical data on billing determinants, the total revenue requirement, and allocation factors calculated from hourly demand and generation data by area in each year.

147. We summarise the transmission charges that are used under our recommended tariff and the current tariff in 2018 and 2019 in Table A.3 below.

[41] Data provided by the AESO.

**Table A.3: Bulk and Regional Transmission Charges Under Current and Our Recommended Tariff in 2018 and 2019**

| Current Tariff | 2018 | 2019 |
|---|---|---|
| 12 CP ($ per MW-month) | 10,177 | 10,524 |
| BC ($ per MW-month) | 2,281 | 2,359 |
| Energy ($ per MWh) | 2.04 | 2.13 |
| **Recommended Tariff** | **2018** | **2019** |
| 12 CP ($ per MW-month) | 5,093 | 6,065 |
| BC ($ per MW-month) | 1,816 | 2,180 |
| Energy ($ per MWh) | 8.80 | 10.68 |

*Note: Billing determinants sourced from AESO data. They may differ to those presented at the AESO's Bulk and Regional Tariff Design Stakeholder Engagement Session 5. Billing determinants are 96,044 (2018) and 97,698 (2019) MW-months for 12CP, 154,214 (2018) and 156,984 (2019) MW-months for billing capacity, and 61,000 (2018) and 59,678 (2019) GWh for energy consumption.*
*Source: NERA Analysis.*

### A.2.2. We calculate how much each customer would pay if it did not self-supply

148. For each industrial customer, we calculate how much the customer would pay to purchase all of its gross demand from the grid under the current and recommended tariff in 2018 and 2019. We use the Price Duration Curves shown above and each customer's total gross demand (in MWh) within each group of hours.[42]

149. We summarise the costs of purchasing power from the grid across all customers under the current and recommended tariff in Figure A.1 below. The total cost that all industrial customers would have incurred to purchase their gross energy requirement from the grid would have increased slightly under our recommended tariff in 2019 relative to the current tariff, but decreased slightly in 2018.

A. The costs of purchasing power from the pool do not change between the two tariff scenarios, as we assume the pool price remains unchanged.

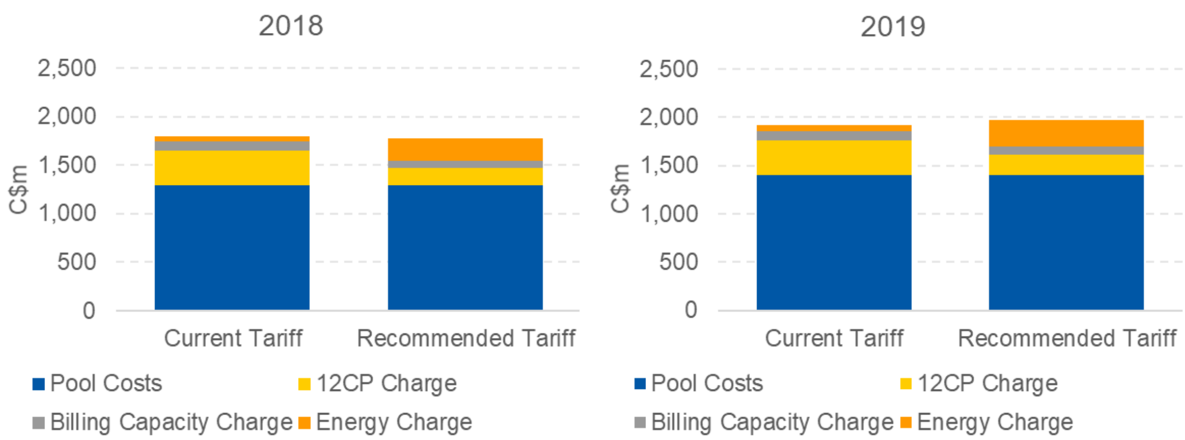
[42] Whilst our use of gross load data allows us to control for customers' existing self-supply decisions, we are unable to control for their load management decisions. In other words, a customer currently avoiding 12CP by reducing or eliminating its load during the 12CP hour, but without self-supplying, appears as if the customer has zero load in the hour. This means that we assume that the customer always chooses to avoid 12CP, if it is currently choosing to do so under the current tariff. Given our recommended tariff reduces the costs recovered by 12CP, our approach is likely to overstate the degree of 12CP avoidance under our recommended tariff.

B. The cost of 12CP charges falls under our recommended tariff, as the 12CP charge is lower under our recommended tariff design.

C. The cost of billing capacity charges falls under our recommended tariff. In our modelling, we assume customers' contract capacity is unchanged irrespective of its self-supply decision, as we assume the customer always relies on the grid for back-up.

D. The costs of paying the energy charge of the transmission tariff rise under our recommended tariff, as the energy charge is higher.

**Figure A.1: Costs of Purchasing Power from the Grid Under the Current and Our Recommended Tariff**




*Note: POD costs not shown. Source: NERA analysis of AESO data.*

### A.2.3. We perform modelling to optimise the self-supply decision for each customer

150. We then perform optimisation modelling to identify the self-supply decision for each customer that would minimise its energy costs.

151. The model allows customers to choose to self-supply from two different technologies, or types of plant that we discuss in Appendix A.2.4 below. We do not constrain the capacity of plants that customers can build to be above a particular size, or the mix of the two alternative technologies. Hence, customers can build any amount (in MW terms) of either or both types of plant. This conservative assumption makes the costs of self-supply appear more attractive than they would be in reality, as generation units

typically come in standardised sizes, so each unit installed cannot be below a certain size.

152. Our model assumes that, if customers invest in plant, they incur capital costs and fixed O&M costs irrespective of how they subsequently use the plant. Having built a plant, the model optimises when the plant should be dispatched for self-supply, up to the capacity of the plant. When a customer self-supplies power from its plant:

A. It incurs variable O&M costs, fuels costs (natural gas costs), and carbon costs.[43]

B. It avoids serving its gross load from the pool, which would incur costs as per the Price Duration Curves shown above.

153. The model assumes that each customer chooses how many MW of each generation technology to build and the hours in which to run it, to minimise its total costs of meeting its gross load. The total cost function, which the model minimises using a "linear program" approach, constitutes the costs of purchasing power from the grid (pool price plus transmission costs) and the costs associated with self-supplying through investing in and running on-site plant.

154. The model chooses how much capacity of each type of plant to build, and how much power to self-supply from each plant in each representative hour. It cannot produce more than the capacity of its plant in each representative hour, and the model is constrained to either use self-supply or power from the grid to meet the customer's gross load.[44]

155. We solve this linear programming problem for each customer (industrial site), under the current and recommended tariff, and separately for both 2018 and 2019. The solution of the problem for each customer defines its optimal self-supply under each tariff and in each year. We illustrate our modelling approach in Figure A.2 below.

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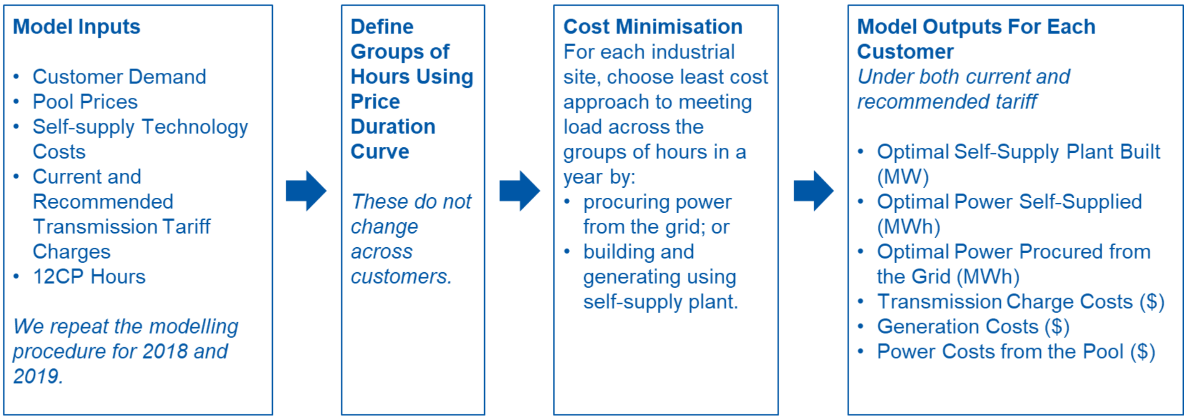
43 Throughout our analysis we source gas costs and forecasts from the Alberta Energy Regulators Forecast of AECO-C gas prices updated June 2020 and accessed here: https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st98/prices-and-capital-expenditure/natural-gas-prices/aeco-c-price. Last Accessed 12 May 2021.

44 We assume that customers cannot use self-supply technology to export power to the grid.

**Figure A.2: Illustration of Our Modelling Approach**




*Source: NERA illustration.*

### A.2.4. Assumed self-supply technologies

156. We allow the model to choose between two technologies for self-supply:

A. An aeroderivative combustion engine (“ACE”) fuelled by natural gas. The costs and assumptions of the ACE are derived from an AESO-commissioned study on the Cost of New Entry Analysis: Combustion Turbines and Combined-Cycle Plants.[45]

B. A reciprocating internal combustion engine (“RICE”) fuelled by natural gas. The RICE costs and assumptions are derived from the AESO Delivered Cost of Energy Report.

157. We summarise our assumptions and sources for costs and operating conditions of each technology, the ACE and RICE, in Table A.4 and Table A.5 below respectively.

45 Johannes P. Pfeifenberger et al. (4 September 2018), AESO Cost of New Entry Analysis: Combustion Turbines and Combined-Cycle Plants with November 1, 2021 Online Date.

**Table A.4: ACE Plant Cost Assumptions and Sources (2019 C$)**

| | *Units* | **ACE** | **Assumption/Source** |
|---|---|---|---|
| **Initial Capex** | *$/kW* | 1,703 | AESO Cost of New Entrant Analysis. Includes an indicative cost of land and upfront financing fees. |
| **Heat Rate** | *GJ/MWh* | 9.68 | AESO Cost of New Entrant Analysis. |
| **Variable O&M** | *$/MWh* | 4.39 | AESO Cost of New Entrant Analysis. |
| **Fixed O&M** | *$/kW-year* | 48.26 | AESO Cost of New Entrant Analysis. |
| **Lifetime** | *years* | 20 | AESO Cost of New Entrant Analysis. |
| **Build time** | *years* | 2 | Based on an internal combustion engine as cited by the EIA. |
| **Emissions Intensity** | *t/MWh* | 0.49 | NERA Calculation using (i) tCO2/therm = 0.0053[46] (ii) Btu/therm = 100,000;[47] therm/GJ = 0.105506.[48] |
| **Rate of return** | *%* | 8.50% | AESO Cost of New Entrant Analysis. |

*Source: NERA Analysis of AESO Cost of New Entry Analysis: Combustion Turbines and Combined-Cycle Plants with November 1, 2021 Online Date; and Energy Information Administration (February 2021), Assumptions to the Annual Energy Outlook 2021: Electricity Market Module.*

46 EIA, Greenhouse Gases Equivalencies Calculator - Calculations and References, Last Accessed 17 May 2021, Link: https://www.epa.gov/energy/greenhouse-gases-equivalencies-calculator-calculations-and-references.

47 EIA, FAQs, Last Accessed 17 May 2021, Link: https://www.eia.gov/tools/faqs/faq.php?id=45&t=8

48 EIA, Energy Conversion Calculators – Natural Gas, Last Accessed 17 May 2021, Link: https://www.eia.gov/energyexplained/units-and-calculators/energy-conversion-calculators.php

**Table A.5: RICE Plant Cost Assumptions and Sources (2019 C$)**

| | *Units* | **RICE** | **Assumption/Source** |
|---|---|---|---|
| **Initial Capex** | *$/kW* | 2,200 | AESO Delivered Cost of Electricity Report 2020. |
| **Heat Rate** | *GJ/MWh* | 10.50 | AESO Delivered Cost of Electricity Report 2020. |
| **Variable O&M** | *$/MWh* | 9.77 | AESO Delivered Cost of Electricity Report 2020. |
| **Fixed O&M** | *$/kW-year* | 0.00 | AESO Delivered Cost of Electricity Report 2020. No fixed O&M costs mentioned in report so assumed to be zero. The risk with our assumption is that we understate the costs of self-supply technologies. |
| **Lifetime** | *years* | 25 | NERA assumption based on lifetime of plants cited in other sources. The AESO cites a 25-year asset life for a simple cycle gas plant in its Summary of Integrated Capacity and Energy Revenue Modelling, but a 20-year asset life for the ACE in the Cost of New Entry Analysis. In order to ensure we do not overstate the costs of self-supply, we assume a 25-year asset life. |
| **Build time** | *years* | 2 | Based on an internal combustion engine as cited by the EIA. |
| **Emissions Intensity** | *t/MWh* | 0.53 | NERA Calculation using (i) tCO2/therm = 0.0053[49] (ii) Btu/therm = 100,000;[50] therm/GJ = 0.105506.[51] |
| **Rate of return** | *%* | 8.20% | NERA assumption based on rate of return cited by AESO for a simple cycle gas turbine in its Summary of Integrated Capacity and Energy Revenue Modelling. |

*Source: NERA Analysis of AESO (31 May 2020), Delivered Cost of Electricity Report; and Energy Information Administration (February 2021), Assumptions to the Annual Energy Outlook 2021: Electricity Market Module.*

158. As can be seen in the above tables, the ACE and RICE have different cost profiles. The ACE has higher fixed costs each year than the RICE. However, the ACE has lower variable costs of generation than the RICE. We summarise the fixed and variable costs of each technology in Table A.6 below.

[49] EIA, Greenhouse Gases Equivalencies Calculator - Calculations and References, Last Accessed 17 May 2021, Link: https://www.epa.gov/energy/greenhouse-gases-equivalencies-calculator-calculations-and-references.

[50] EIA, FAQs, Last Accessed 17 May 2021, Link: https://www.eia.gov/tools/faqs/faq.php?id=45&t=8

[51] EIA, Energy Conversion Calculators – Natural Gas, Last Accessed 17 May 2021, Link: https://www.eia.gov/energyexplained/units-and-calculators/energy-conversion-calculators.php

**Table A.6: ACE and RICE Variable and Fixed Costs (2019 C$)**

| | ACE | RICE |
|---|---|---|
| **Fixed Cost ($/kW/yr)** | 228 | 210 |
| **Variable Cost ($/MWh)** | 23.35 | 31.29 |

*Source: NERA Analysis*

159. Therefore, the ACE is a self-supply option similar to the baseload generation option that we outline in Paragraph 27 above. Whilst it is more expensive to build, it is more economically viable than RICE technology when run for more hours of the year, due to its lower variable costs. On the other hand, the RICE is similar to the peaking generation option that we outline in Paragraph 27 above. Whilst it is cheaper to build, it is only more economic than the ACE in fewer hours, due to its higher variable costs.

160. We considered a range of potential self-supply technologies in our analysis, drawing on both AESO studies as well as studies from the US Energy Information Administration ("EIA"). We summarise the characteristics of some of the alternative options we considered in Table A.7 below.

    A. A key component of our assumption of available self-supply technologies is the size of the plant. For instance, whilst grid-scale CCGTs are more efficient than our chosen technologies, in practice, most industrial customers are unable to install a CCGT to self-supply because the minimum size of the plant is too large relative to an industrial customers' typical load.[52]

    B. Therefore, we focus our analysis on plants with smaller minimum sizes for use in self-supply. In our optimization of the customers' self-supply decision, we do not constrain the minimum size of plant that the customer can build, and therefore our choice of self-supply technology should be appropriate for small-scale plant. Hence, we do not consider CCGT, Frame Combustion Turbine ("Frame CT"), and Simple Cycle Gas Turbine ("SCGT") technologies. Whilst the SCGT plant is similar in size to the ACE plant that we adopt, we consider the ACE plant to be

[52] For similar reasons, we assume that industrial customers cannot utilise intermittent technologies (combined with battery storage) because these technologies require significant land and therefore cannot be used to materially offset load. The AESO states, for industrial and large commercial customers, that "area available for PV arrays is likely insufficient to offset load" in its discussion of self-supply technologies in its Delivered Cost of Electricity Report. Source: AESO (May 2020), Delivered Cost of Electricity Report, p. 28.

more representative of the costs of installing self-supply technology, as the fixed cost estimate also includes other costs that merchant generators would incur in Alberta e.g. including an indicative cost of land.[53]

C. We considered using plant assumptions as detailed by the EIA in its Assumptions to the Annual Energy Outlook 2021.[54] More specifically, we considered utilising a distributed generation baseload gas plant ("DG Base"), and a distributed generation peaking gas plant ("DG Peak"). Both of these plants have small sizes of 2 MW and 1 MW respectively, and are therefore suitable for self-supply. The EIA also provides data for an Internal Combustion Engine ("ICE") which has a size of 21 MW which is likely more appropriate for self-supply options compared to the ACE which has a size of 93 MW.

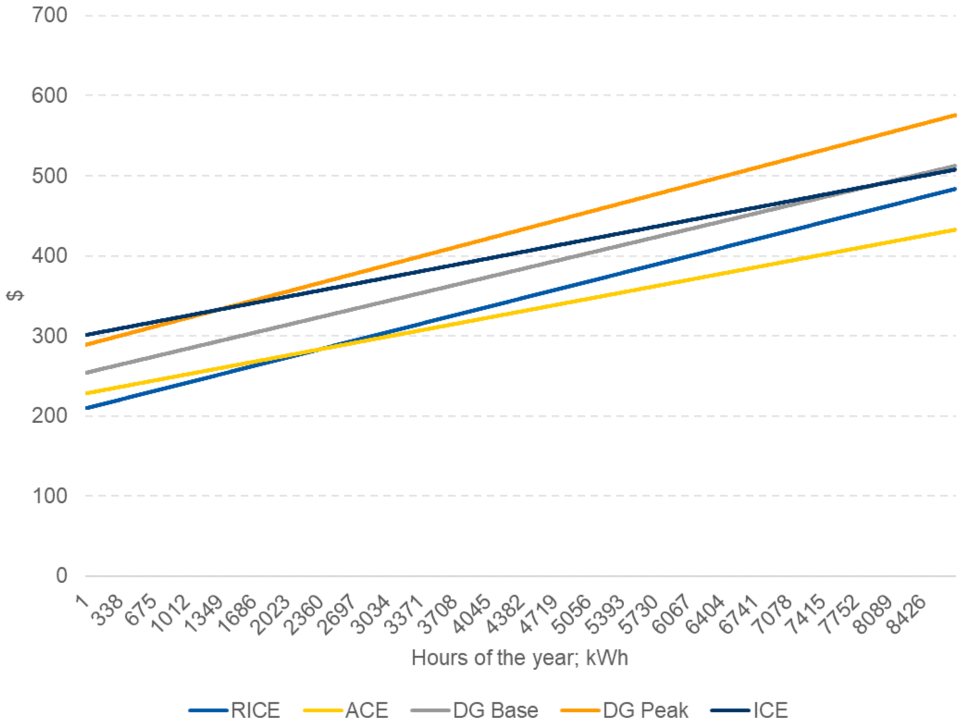
D. However, these plants are not cost competitive compared to the ACE and RICE plants. To illustrate this, we calculate a screening curve for the remaining self-supply technologies. The screening curve illustrates, for each technology, the total costs of building a 1 kW plant and then operating that plant for various hours of the year, generating 1 kWh per hour that it operates. We illustrate our screening curve in Figure A.3 below. It shows that either ACE or RICE technologies are the least cost technologies, across any amount of running hours.

53 The AESO source for the CCGT and SCGT were also cited in the context of the proposed capacity market which was not enacted. Source: AESO (January 2018), Summary of Integrated Capacity and Energy Revenue Modelling.

For land costs and other costs in the capital cost of the ACE plant, see: Johannes P. Pfeifenberger et al. (4 September 2018), AESO Cost of New Entry Analysis: Combustion Turbines and Combined-Cycle Plants with November 1, 2021 Online Date, Table 8.

54 Energy Information Administration (February 2021), Assumptions to the Annual Energy Outlook 2021: Electricity Market Module.

**Figure A.3: Screening Curve for Self-Supply Technologies (2019 C$)**




*Source: NERA Analysis.*

**Table A.7: Self-Supply Technology Characteristics (2020 C$)**

| Cost | *Units* | RICE | CCGT | SCGT | ACE | Frame CT | CCGT | DG Base | DG Peak | ICE | CCGT |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Initial Capex** | *$/kW* | 2,200 | 2,089 | 1,453 | 1,703 | 769 | 1,742 | 2,398 | 2,765 | 2,675 | 1,471 |
| **Heat Rate** | *GJ/MWh* | 10.50 | 7.20 | 10.50 | 9.68 | 10.06 | 6.81 | 9.43 | 10.47 | 8.75 | 6.72 |
| **Variable O&M** | *$/MWh* | 9.77 | 8.26 | 4.13 | 4.39 | 0.76 | 2.57 | 11.33 | 11.33 | 7.49 | 2.46 |
| **Fixed O&M** | *$/kW-yr* | | 27.88 | 18.58 | 48.26 | 25.37 | 44.44 | 25.49 | 25.49 | 46.30 | 16.06 |
| **Lifetime** | *years* | | | 25 | 20 | 20 | 20 | | | | |
| **Build time** | *years* | 2 | 3 | 2 | 2 | 2 | 3 | 3 | 2 | 2 | 3 |
| **Size** | MW | <5 | 455 | 100 | 93 | 243 | 279 | 2 | 1 | 21 | 1083 |
| **Emissions intensity*** | *t/MWh* | 0.53 | 0.36 | 0.53 | 0.49 | 0.51 | 0.34 | 0.47 | 0.53 | 0.44 | 0.34 |
| **Rate of return** | *%* | | | 8.20% | 8.50% | 8.50% | 8.50% | | | | |
| **Levelised Cost (incl Fixed O&M)** | *$/kW/yr* | 209.62 | 226.91 | 157.06 | 228.24 | 106.64 | 228.50 | 253.94 | 288.98 | 301.21 | 156.21 |
| *Source:* | | *AESO (1)* | *AESO (2)* | *AESO (2)* | *AESO (3)* | *AESO (3)* | *AESO (3)* | *EIA* | *EIA* | *EIA* | *EIA* |

** Note: We recalculated all emissions intensities using the same assumptions for consistency and comparability. Our assumptions included (i) tCO2/therm = 0.0053[55] (ii) Btu/therm = 100,000;[56] therm/GJ = 0.105506.[57] Source: NERA Analysis of (1) AESO (31 May 2020), Delivered Cost of Electricity Report; (2) AESO (January 2018), Summary of Integrated Capacity and Energy Revenue Modelling; (3) Johannes P. Pfeifenberger et al. (4 September 2018), AESO Cost of New Entry Analysis: Combustion Turbines and Combined-Cycle Plants with November 1, 2021 Online Date, Table 8; and Energy Information Administration (February 2021), Assumptions to the Annual Energy Outlook 2021: Electricity Market Module.*

55 EIA, Greenhouse Gases Equivalencies Calculator - Calculations and References, Last Accessed 17 May 2021, Link: https://www.epa.gov/energy/greenhouse-gases-equivalencies-calculator-calculations-and-references.

56 EIA, FAQs, Last Accessed 17 May 2021, Link: https://www.eia.gov/tools/faqs/faq.php?id=45&t=8

57 EIA, Energy Conversion Calculators – Natural Gas, Last Accessed 17 May 2021, Link: https://www.eia.gov/energyexplained/units-and-calculators/energy-conversion-calculators.php

### A.2.5. Additional model assumptions

161. We also make assumptions relating to inflation, exchange rates, gas costs, and carbon costs. We detail these assumptions and our sources in Table A.8 below.

**Table A.8: Overview of Model Assumptions**

| Assumption | Units | 2018 | 2019 | 2020 | Source |
|---|---|---|---|---|---|
| **Exchange Rate** | US$ to C$ | 1.2957 | 1.3269 | 1.3415 | Bank of Canada, Annual Average Exchange Rates, Link: https://www.bankofcanada.ca/rates/exchange/annual-average-exchange-rates/, Last Accessed 05/05/2021. |
| **Inflation Rate** | % | 1.40% | 2.40% | 1.84% | Inflation calculated as YoY percentage change in CPI from January each year. Source: Bank of Canada, Consumer Price Inflation, Link: https://www.bankofcanada.ca/rates/price-indexes/cpi/, Last Accessed 05/05/2021. |
| **Gas Cost** | $ per GJ | 1.48 | 1.6 | 1.92 | AER Forecast of AECO-C Gas. Average Annual Price, Base Case. |
| **Carbon Cost** | $ per tCO2 | 30 | 30 | 30 | Government of Alberta (June 2018), Climate Leadership Plan 2018-2019. |

*Source: NERA Analysis.*

### A.2.6. Estimating optimal self-supply for customers

162. We run the model to estimate each customer's optimal self-supply decision using data for both 2018 and 2019 under both the current and recommended tariff designs. Our optimization model chooses the least cost combination of self-supply and purchasing of power from the grid across the year for each customer to meet its load.

163. In Table A.9 below, we outline the optimal investment in ACE and RICE plant resulting from our model of optimal self-supply decisions across customers under the current and recommended tariff. We find that most customers in our model build ACE plant, which has higher fixed costs than the RICE plant but lower variable costs. Under the recommended tariff, customers invest in more ACE plant but less RICE plant, suggesting that customers find it optimal to self-supply in more hours of the year due to the higher energy charge, thereby opting for the baseload instead of peaking technology.

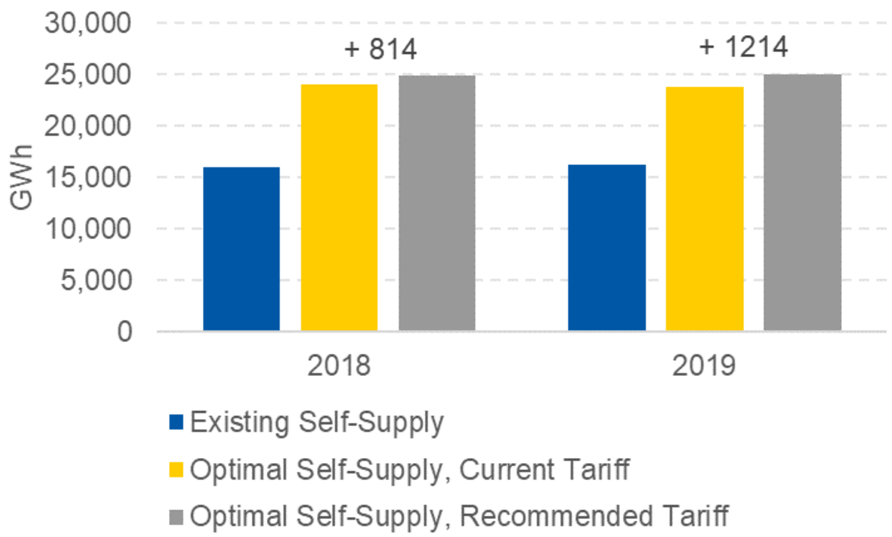
**Table A.9: Modelled Optimal Self-Supply Plant Under Current and Recommended Tariff in 2018**

| | Capacity (MW) | ACE Capacity | RICE Capacity |
|---|---|---|---|
| **Current Tariff** | 2,872 | 2,850 | 22 |
| **Recommended Tariff** | 2,893 | 2,887 | 6 |
| **Difference** | 21 | 37 | -16 |

*Source: NERA Analysis.*

164. We illustrate the total change in energy self-supplied under the current and recommended tariff in Figure A.4 below. Our model suggests that optimal self-supply under the current tariff (yellow bars) is slightly lower than under our recommended tariff (grey bars). We find that moving from the current to the recommended tariff marginally increases optimal self-supply for customers in our sample by 814 GWh and 1,214 GWh in 2018 and 2019 respectively.

**Figure A.4: Modelled Optimal Self-Supply Under Current and Recommended Tariff in 2018 and 2019**




*Source: NERA Analysis.*

165. However, as can be seen in the figure, our model suggests much higher optimal self-supply under the current tariff (the yellow bars) than actually observed self-supply in 2018 and 2019 (the blue bars). Our model suggests optimal self-supply is approximately 50 and 47 per cent greater under the current tariff than actual self-

supply under the current tariff. This finding is similar to the AESO's finding in the Delivered Cost of Electricity Report, as we discuss in Section 3.4.2 above.

166. We would expect to observe this result for two key reasons:

A. Our model understates the cost of self-supply technologies. As we discuss in Appendix A.2.3, our model allows customers to build increments of capacity of self-supply technologies as we do not restrict the customer to a minimum size of plant. We also choose technologies available for self-supply that are more cost competitive than smaller plants appropriate for distributed generation but with higher operating costs.

B. Our model only considers the costs of self-supply associated with the fixed and variable costs of operating self-supply generators. In reality, customers incur other costs in their decision to self-supply, such as the costs and risks associated with business complexity and financing. Other industrial customers may not be able to self-supply due to their location in the province or lack of available land. We cannot directly observe these other costs associated with self-supply in the data available.

167. Therefore, to account for the additional costs associated with self-supply, we examine how customers' actual decisions to self-supply are linked to the incentive to self-supply identified by our optimisation modelling, as explained below.

## A.3. Step 2: Estimating the Actual Self-Supply Response by Customers

168. We estimate a statistical relationship between actual self-supply decisions and the incentive to self-supply (as measured by the optimal self-supply generation amount predicted by our model in Step 1).[58]

169. We use an Ordinary Least Squares regression procedure to estimate the statistical relationship between actual self-supply and the incentive to self-supply across customers. In our regression, our dependent variable (the variable we are explaining)

58 We could have utilized data for both 2018 and 2019 to estimate the statistical relationship. However, we only use data in 2018 so that we can test the performance of our model in predicting actual self-supply in 2019, as we discuss in Appendix A.3.2 below.

is total actual self-supply by customer across 2018 (in MWh), defined by the difference between each customer's metered gross demand and its metered net demand.

170. We use the total optimal self-supply by customer across 2018 (in MWh), taken from our model as our measure of the *incentive* to self-supply as an explanatory variable (the variable we are using to predict actual self-supply) in the regression. We illustrate our approach in Figure A.5.

**Figure A.5: Illustration of Our Regression Approach**

$$\text{Actual Self-Supply} = \alpha + \beta*(\text{Incentive to Self-Supply}) + \varepsilon$$

*Where:*

$$\text{Incentive to Self-Supply} = \text{Modelled Optimal Self-Supply}$$

*$\alpha$ and $\beta$, are constants to be estimated, $\varepsilon$ is an error term.*

*Source: NERA illustration.*

171. Put simply, this procedure allows us to predict how much a customer would typically self-supply, as a function of how much an optimisation model suggests the customer should self-supply if it were making a least-cost trade-off between self-generation costs and purchasing power from the grid, as shown above.

### A.3.1. We include a number of explanatory variables in our regression

172. We include a number of other explanatory variables that allow different customers to respond to the incentive to self-supply in different ways, depending on their characteristics. Formally, we use "interaction terms" in our regression which allow the statistical relationship between actual self-supply and the incentive to self-supply to change depending on customer characteristics. We include the following customer characteristics in our regression:

A. Contract Capacity: We allow the response of customers to the incentive to self-supply to change with contract capacity. As discussed in Appendix A.2, we assume each site contains a single industrial customer.

B. Industry Type: Customers' response to the incentive to self-supply might change depending on its industrial processes. We allow the response of customers to change with each customer's industry type. More specifically, we estimate different customer responses for the wood industry (pulp and paper or wood production), oilsands industry, pipeline industry, or other industry (chemical, steel, cement). We estimate a different customer response for customers with no listed industry.

C. Location in a City: We allow the response of customers to change if the customer is located in the Calgary or Edmonton planning region. Customers in more densely populated areas may have less land available for self-supply technology, reducing their responsiveness to the incentive to self-supply.

D. Industry System Designation ("ISD"): We allow the response of customers to change if the customer already has ISD status. We would expect customers with ISD status to be more responsive to the incentive to self-supply.

173. Formally, our regression is written in Table A.10 below.

**Table A.10: Our Regression Approach**

| Type of Variable | Variable |
|---|---|
| Dependent Variable | Actual Self-Supply (MWh) |
| Constant | Constant |
| Explanatory Variable 1 | Incentive to Self-Supply (MWh) |
| Explanatory Variable 2 | Incentive to Self-Supply (MWh) x Contract Capacity (MW) |
| Explanatory Variable 3a | Incentive to Self-Supply (MWh) x Wood Industry (1/0 Dummy) |
| Explanatory Variable 3b | Incentive to Self-Supply (MWh) x Oilsands Industry (1/0 Dummy) |
| Explanatory Variable 3c | Incentive to Self-Supply (MWh) x Pipeline Industry (1/0 Dummy) |
| Explanatory Variable 3d | Incentive to Self-Supply (MWh) x Other Industry (1/0 Dummy) |
| Explanatory Variable 4 | Incentive to Self-Supply (MWh) x Located in City (1/0 Dummy) |
| Explanatory Variable 5 | Incentive to Self-Supply (MWh) x ISD (1/0 Dummy) |
| Residual | Residual Term |

*Note: A dummy variable takes the value of 1 if true for a customer or 0 otherwise. For instance, if a customer has an ISD then the dummy variable will equal 1, otherwise it will equal 0. Source: NERA Analysis.*

### A.3.2. We estimate our regression and analyse its predicative power using 2019 data

174. We estimate our regression using 2018 data and present our results in Table A.11.

**Table A.11: Our Estimated Regression Using 2018 Data**

| Dependant Variable: MWh of Actual Self-Supply | Coefficient | p-Value |
|---|---|---|
| Incentive to Self-Supply<br>*(MWh of Optimal Self-Supply as Estimated by Model)* | 0.174 | 0.106 |
| Interaction with ISD | 0.485 | 0.000 |
| Interaction with Contract Capacity | -0.001 | 0.000 |
| Interaction with City | -0.301 | 0.185 |
| R-Squared | 0.9696 | |
| Number of Observations | 133 | |

*Notes: Interactions with Industry Types Not Shown but Included in Model. All industry interaction explanatory variables are statistically significant with the exception of "pipeline". Incentive to self-supply is statistically significant when tested across all interaction terms. Source: NERA Analysis.*

175. Our estimated regression suggests that as the incentive to self-supply increases, as measured by a 1 MWh increase in the optimal amount of self-supply identified by our model, actual self-supply by customers increases. We estimate how this relationship is affected by the characteristics of the customer:

A. A customer with an ISD is found to be more responsive to the incentive to self-supply, increasing its actual self-supply by 0.485 MWh more than a customer without an ISD in response to a 1 MWh increase in the amount of self-supply that the optimisation model in Step 1 suggests is least cost.

B. A customer located in the Edmonton or Calgary planning regions is found to be less responsive to the incentive to self-supply, increasing its actual self-supply by 0.301 MWh less than a customer outside these regions in response to a 1 MWh increase in the amount of self-supply that the optimisation model in Step 1 suggests is least cost.

C. Contract capacity has a statistically significant and negative impact on the customer response to the incentive to self-supply. However, the size of this impact is very small.

176. Our regression also has a high degree of statistical fit, meaning that it explains the majority of the variation in actual self-supply across customers. Formally, the R-squared of our regression is 0.9696, meaning our regression explains 96.96 per cent of the variation in actual self-supply across customers in 2018 using the explanatory

variables. This is reassuring as it means our model has a strong predicative power to estimate actual self-supply from the amount of self-supply that the optimisation model in Step 1 suggests is least cost.

177. To further assess the predicative power of our regression, we use it to predict self-supply in 2018 and 2019 across industrial customers. We would expect our regression to perform well at predicting 2018 actual self-supply, because we estimate the regression using 2018 data. However, in this calculation we are particularly interested in the performance of our regression at predicting 2019 self-supply decisions, because this data is not used to calibrate the regression equation. We detail our results for our sample of customers in Table A.12 below.

**Table A.12: Analysis of the Predicative Power of Our Regression**

| | **2018** | **2019** |
|---|---|---|
| Modelled Incentive to Self-Supply (GWh) | 24,114 | 23,851 |
| Actual Self-Supply (GWh) | 16,055 | 16,245 |
| **Predicted Self-Supply Using Regression (GWh)** | **16,624** | **16,534** |
| Difference Between Predicted and Actual Self-Supply (GWh) | 570 | 289 |
| **Prediction Error Relative to Actual Self-Supply (%)** | **3.55%** | **1.78%** |

*Source: NERA Analysis of AESO Data*

178. Our regression performs well in predicting actual self-supply by customers in 2019. It predicts a volume of self-supply in 2019 within 2 per cent of the actual self-supply volume observed in that year. Therefore, we are reassured that our regression performs well at predicting actual self-supply based on data that is "out of sample", i.e. data that is not used to initially estimate the regression such as 2019 data.

179. Consequently, we are content that our regression predicts accurately the actual self-supply response by customers.

### A.3.3. We considered alternative specifications of our regression

180. We considered an alternative specification of our regression which uses the cost savings associated with optimal self-supply relative to purchasing all power from the grid as a measure of the incentive to self-supply (rather than the MWh of optimal self-supply as in the "MWh Regression" above).

181. Similar to our "MWh Regression" our "Cost Regression" uses the same interaction terms to allow customers' responsiveness to the incentive to self-supply, as measured by our modelled costs savings associated with self-supply, to differ with their characteristics.

182. We estimate our "Cost Regression" using 2018 data and present our results in Table A.13.

**Table A.13: Our Estimated "Cost Regression" Using 2018 Data**

| Dependant Variable: MWh of Actual Self-Supply | Coefficient | p-Value |
|---|---|---|
| Incentive to Self-Supply<br>*(Cost Savings of Optimal Self-Supply as Estimated by Model)* | 0.0093 | 0.103 |
| Interaction with ISD | 0.0254 | 0.000 |
| Interaction with Contract Capacity | -0.0001 | 0.000 |
| Interaction with City | -0.0172 | 0.169 |
| R-Squared | 0.9697 | |
| Number of Observations | 133 | |

*Notes: Interactions with Industry Types Not Shown but Included in Model. All industry interactions explanatory variables are statistically significant with the exception of "pipeline". Incentive to self-supply is statistically significant when tested across all interaction terms. Source: NERA Analysis.*

183. Our estimated "Cost Regression" suggests that as the incentive to self-supply increases, as measured by the cost savings associated with optimal self-supply relative to purchasing power from the grid in our model, actual self-supply by customers increases. We estimate that this relationship is also affected by the characteristics of the customer in a similar way to the "MWh Regression" as detailed in Table A.11 above.

184. Our "Cost Regression" also has a high degree of statistical fit, meaning that it explains the majority of the variation in actual self-supply across customers. The R-squared of our regression is 0.9697, meaning our regression explains 96.97 per cent of the variation in actual self-supply across customers in 2018 using the explanatory variables we include in it.

185. Similar to our test for the "MWh Regression", we further assess the predictive power of the "Cost Regression" by predicting self-supply in 2018 and 2019 across industrial

customers using our regression. We detail our results for our sample of customers in Table A.14 below.

**Table A.14: Analysis of the Predicative Power of Our Regression**

| | 2018 | 2019 |
|---|---|---|
| Modelled Incentive to Self-Supply (GWh) | 24,114 | 23,851 |
| | | |
| Actual Self-Supply (GWh) | 16,055 | 16,245 |
| **Predicted Self-Supply Using Regression (GWh)** | **16,605** | **19,561** |
| | | |
| Difference Between Predicted and Actual Self-Supply (GWh) | 550 | 3,316 |
| **Prediction Error Relative to Actual Self-Supply (%)** | **3.43%** | **20.41%** |

*Source: NERA Analysis of AESO Data*

186. Our "Cost Regression" performs better than our "MWh Regression" at predicting self-supply by customers in 2018.

187. However, our "Cost Regression" performs less well at predicting 2019 self-supply than our "MWh Regression", resulting in it predicting self-supply that is approximately 20 per cent higher than actually observed under the current tariff. We therefore use our "MWh Regression" to predict the actual self-supply response by customers to our recommended tariff in Appendix A.4 below.[59]

## A.4. Step 3: Our Estimate of Self-Supply by Customers

### A.4.1. Estimating the change in self-supply volumes due to the change in tariff design

188. Using our preferred specification, the "MWh Regression", we predict how self-supply by industrial customers would change under our recommended tariff design using data for 2018 and 2019. We report our results in Table A.15 below. We calculate two changes in self-supply:

A. We calculate the difference between predicted self-supply under our recommended tariff and predicted self-supply under the current tariff, where both are predicted using our modelling and regression procedure described above.

[59] We also considered logarithmic regressions to estimate the percentage increase in actual self-supply in response to a percentage increase in the incentive to self-supply. However, we could only estimate the logarithmic model on customers who are currently self-supplying (to prevent introducing non-linearity to the data) and these customers may be systematically different to the customers not self-supplying, leading to systematic bias in our estimate of self-supply.

This is shown in Row C of the table below. This calculation shows the change in self-supply predicted by our modelling procedure due to the change in the tariff design.

B. We calculate the difference between predicted self-supply under our recommended tariff and *actual* self-supply, as observed under the current tariff. This is shown in Row E of the table below. In other words, this calculation compares our modelled projection of self-supply after the change in the tariff design to the actual volume of self-supply today, i.e. under the current methodology.

**Table A.15: Our Estimate of Customer Self-Supply in 2018 and 2019 Under Our Recommended Tariff**

| | *Units: GWh* | **2018** | **2019** |
|---|---|---|---|
| A | Predicted Self-Supply Under Recommended Tariff | 17,249 | 17,401 |
| B | Predicted Self-Supply Under Current Tariff | 16,624 | 16,534 |
| **C = A – B** | **Change in Self-Supply Under Recommended Tariff Relative to *Predicted* Self-Supply Under Current Tariff** | **625** | **867** |
| D | Actual Self-Supply Under Current Tariff | 16,055 | 16,245 |
| **E = A – D** | **Change in Self-Supply Under Recommended Tariff Relative to *Actual* Self-Supply Under Current Tariff** | **1,194** | **1,156** |

*Source: NERA Analysis.*

189. We therefore predict an increase in self-supply across customers in our sample of between 625 and 1,194 GWh, depending on the approach used.

190. As we discuss in Appendix A.3.2, our regression overstates self-supply when compared against actual self-supply under the current tariff. Therefore, we control for this tendency by comparing our estimate of self-supply under the recommended tariff with *predicted* self-supply under the current tariff using our modelling procedure (Row C), rather than compare it to *actual* self-supply under the current tariff. If we do this, our model predicts an increase in self-supply across customers in our sample of 625 to 867 GWh.

191. We only model the optimal self-supply decision for industrial-only sites. Other industrial customers are located on shared sites with residential and other customers.

Therefore, to ensure we do not understate the incentive to self-supply, we scale our results to account for the industrial customers located on sites outside of our sample. More specifically, we calculate the scaling factor by examining the proportion of total industrial contract capacity constituted by our sample, and scaling by the result, as we show in Table A.16 below.

**Table A.16: Calculation of the Scaling Factor for Our Modelling**

| | | |
|---|---|---|
| A | Industrial-Only Site Contract Capacity | 3,470 MW |
| B | Total Industrial Contract Capacity | 7,186 MW |
| C = B / A | Scaling Factor | 2.071 |

*Source: NERA Analysis of AESO Data.*

192. Scaling our results using this factor, **we estimate that self-supply will increase under our recommended tariff by 1,294 to 2,473 GWh relative to the current tariff** (not controlling for our model's tendency to overstate self-supply). This is equivalent to 2.17 to 4.14 per cent of the total metered energy billing determinant, used to calculate the transmission energy charge, in 2019.

193. Therefore, we estimate that customer response to our recommended tariff will be extremely limited.

### A.4.2. We also considered whether a further customer response might arise from lower energy demand increasing the tariff

194. As customers choose to self-supply, the total metered energy billing determinant reduces. The AESO's revenue requirement does not change in the short run due to changes in demand,[60] so if customers choose to self-supply, the AESO needs to recover the same revenue requirement from a smaller billing determinant, resulting in a higher energy charge.[61] Therefore, whilst we estimate above an initial or "direct" self-supply response of between 1,294 to 2,473 GWh, we also need to account for any

60 In the long run, as we discuss in Section 3.1.2, changes in self-supply decisions will result in changes in the AESO's costs.

61 In practice, our recommended tariff methodology will adjust the division of costs with the changing use of the grid, as we estimate classification and allocation factors based on area level data. Therefore, decisions to self-supply will impact the classification of costs to energy. For simplicity, we maintain the same classification of costs for the purposes of this exercise.

In addition, reductions in energy consumption will also reduce the pool price and therefore the costs associated with purchasing electricity from the grid. Again for simplicity, we do not account for this factor in our analysis leading us to potentially overstate the self-supply response.

further self-supply response resulting from the direct self-supply response increasing the transmission tariff to the remaining customers.

195. We therefore recalculate our recommended tariff, with the energy charge recalculated using total metered energy *less* the direct self-supply response.[62] We use our highest estimate of the self-supply response (2,473 GWh) to recalculate the tariff. Our recalculated tariff has a higher energy charge but the same 12CP and billing capacity charge. We then estimate the change in self-supply using the same modelling procedure described above.

196. Having completed this procedure to estimate the "secondary" impact, we repeat the procedure a third time. We summarise our calculations and results in Table A.17 and Figure A.6 below.

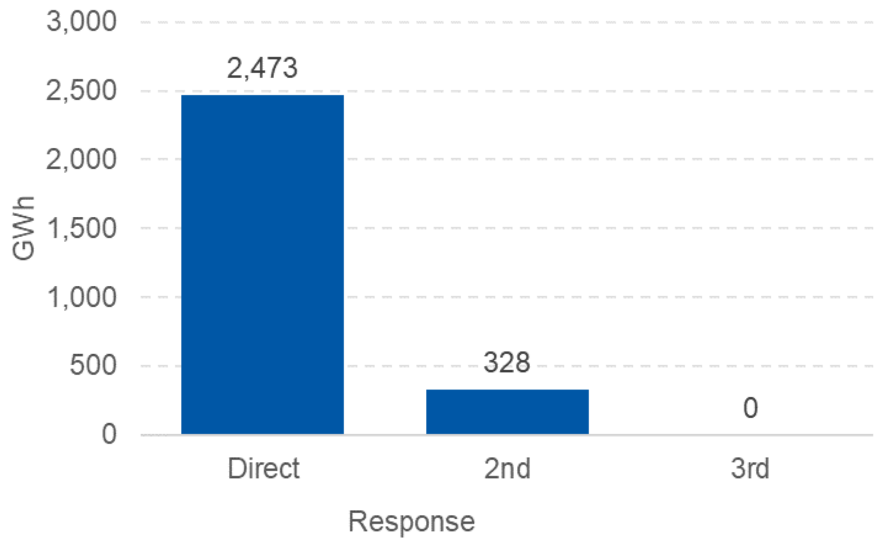
**Table A.17: Our Estimate of the Dynamic Self-Supply Response to Our Recommended Tariff**

| | Direct | 2nd | 3rd |
|---|---|---|---|
| **Costs Recovered from Energy Charge (C$m)** | 638 | 638 | 638 |
| **Energy Billing Determinant (GWh)** | 59,678 | 57,205 | 56,877 |
| **Energy Charge ($ per MWh)** | 10.68 | 11.14 | 11.21 |
| **Estimated Self-Supply Under Recommended Tariff (GWh)** | **17,249** | **17,407** | **17,407** |
| **Estimated Self-Supply Under Current Tariff (GWh)** | 16,055 | | |
| **Additional Self-Supply Response (After Scaling, GWh)** | **2,473** | **328** | **0** |

*Note: * Numbers from 2018 as we take our maximum estimate of self-supply as our direct response to the tariff. Remaining numbers estimated using 2019 data. Source: NERA Analysis*

62 We use 2019 data in this modelling exercise.

**Figure A.6: Our Estimate of the Dynamic Self-Supply Response to Our Recommended Tariff**




*Source: NERA Analysis.*

197. These results show that any further increase in self-supply would be extremely limited. Even taking the top end of our estimated range, we estimate the total self-supply response will total 2,801 GWh. This is equivalent to 4.69 per cent of the total metered energy billing determinant, used to calculate the transmission energy charge, in 2019. It is also equivalent to a total cost shift of C$ 29.92 million (in real 2019 terms) from self-supply customers to other customers, which is approximately 4.69 per cent of total costs allocated to the flow of in-merit energy in 2019 and 1.90 per cent of the total revenue requirement for bulk and regional costs in 2019.

## Qualifications, assumptions and limiting conditions

NERA Economic Consulting ("NERA") has been asked to estimate the likely customer response and potential changes in self-supply outcomes by load arising from the Bulk and Regional tariff design that we recommended to the Alberta Electric System Operation ("AESO"), as described at the AESO's Bulk and Regional Tariff Design Stakeholder Engagement Session 5. The primary audience for this report includes AESO and interested Stakeholders.

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