Stakeholder Perspectives on Rate Design Reform

PREPARED FOR

New Brunswick Energy and Utilities Board

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Appendix

New Brunswick Energy and Utilities Board, Letter to All Parties in Matter 357, May 14, 2019

I. Introduction

This project was carried out through an extensive stakeholder process consisting of three workshops, each employing the Chatham House Rule.[1] These workshops were called for by the New Brunswick Energy and Utilities Board ("the Board") Staff in response to Matter 357, which identified several rate design topics for the Board's consideration.

The Brattle Group ("Brattle") was retained by the Board to assist the stakeholders with (i) identifying issues for determination in Matter 357 based on the evidentiary record and comments from stakeholders, and (ii) determining what issues should and can be resolved in the immediate, medium, and long-terms. Accordingly, this report predominantly represents the stakeholders' perspectives rather than those of Brattle.

The Board noted that the goals of the current review of rate design include reducing inequities, establishing a design that is easily adaptable to future changes (*e.g.*, technology and the business environment), and establishing a rate design that is clear, managed, and predictable.[2]

At the onset of the first workshop, the common sentiment among both the stakeholder participants and the Board Staff was that they were seeking direction as to what issues should be addressed, and when to address them. Multiple stakeholders expressed a desire for that directional path to be both transparent and flexible, so that adjustments could be made as needed based on concurrent decisions and changes that are occurring in the province. At the same time, there was a desire that decisions be made at a time and in such a way that the possibility of reversals (and associated customer confusion) would be minimized.

The first workshop was held on June 26, 2019, the second on July 24–25, 2019, and the third on September 19–20, 2019. At these workshops, several issues were first presented by Brattle, discussed qualitatively by going around the room, and then evaluated through a series of scorecard exercises. In the scorecard exercise, each organization was given a hundred points and asked to allocate the hundred points across the issues being discussed. They could spread them however they wanted across the issues. When the scoring was done, the results were summarized and presented to the group. Also shown was the variance in responses by issue. Another round of discussion followed.

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1 According to this rule, participants are free to use the information received, but neither the identity nor the affiliation of the speaker(s), nor that of any other participant, may be revealed. See https://www.chathamhouse.org/chatham-house-rule/translations.

2 See New Brunswick Energy and Utilities Board, Letter to All Parties in Matter 357, May 14, 2019, included as Appendix.

More specifically, the first workshop on June 26 began with a review of workshop objectives and a presentation by Brattle on frequently asked questions about rate design. In the afternoon session, there was a scorecard exercise and group discussion about rate design objectives, followed by a scorecard exercise and group discussion about rate design choices to achieve these objectives.

The first day of the second workshop on July 24 began with a summary of the first workshop and a review of the results of the preliminary scorecard exercises, followed by a Brattle presentation on the interaction between the investment in Advanced Metering Infrastructure (AMI)[3] and modern rate design. The afternoon session continued with scorecard exercises and group discussions to identify innovative rate design options in the absence of AMI and then repeated assuming that AMI was in place. On day two of the workshop, Brattle presented a draft outline of this report and solicited initial reactions and discussion from the working group.

Based on the results of the first two workshops, Brattle prepared and circulated a draft version of this report, which included a preliminary proposed sequencing of issues for discussion at the third workshop. On the first day of the third workshop on September 19, Brattle presented the list of issues and the proposed sequencing identified in the draft report. This was followed by a group discussion of each of the issues, and then a sequencing exercise in which each stakeholder organization was invited to fill out its own sequencing chart. On the following morning of September 20, stakeholders reviewed the results of the sequencing exercise, discussed areas of consensus and divergence, and provided general comments on the draft stakeholder report and perceived next steps.

Finally, stakeholders were given a week following the conclusion of the third workshop to provide written comments and redlines on the draft report. Many of these edits have been incorporated into this final stakeholder report.

The following participants contributed to the discussions at one or more of the workshops:

- New Brunswick Energy and Utilities Board Staff
- NB Power Staff with a subject matter expert from Elenchus Research Associates and another subject matter expert from Christensen Associates Energy Consulting
- New Brunswick Public Intervener with a subject matter expert from Industrial Economics, Incorporated
- Representatives of Enbridge Gas New Brunswick (EGNB) with a subject matter expert from Concentric Energy Advisors
- Representatives of J.D. Irving, Ltd., a large industrial customer
- Representatives of the Canadian Federation of Independent Business
- Utilities Municipal with a subject matter expert from BDR NorthAmerica, Inc.
- Union of New Brunswick Municipalities

3 AMI is used interchangeably with smart meters throughout this report.

- David Amos, an individual ratepayer
- Gerald Bourque, an individual ratepayer
- Dr. Roger Richard, an individual ratepayer

The makeup of the stakeholder group was such that residential customers did not have anyone with rate design experience acting directly on their behalf or anyone officially representing their customer class exclusively. The mandate of the Public Intervener is broader than representing only the interests of residential customers.

It was noted that NB Power is hearing from its customers through surveys that they:

1. Want to save money.
2. Are open to new technology and want NB Power to take the lead.
3. Want more information and education on all topics related to energy.
4. Are open to changing when they use power to lower their bill, reduce NB Power's costs, or reduce GHG emissions.

It was noted that this material could help the Board or others elicit additional input in future public consultation work on rate design. Stakeholders also affirmed the value in using a stakeholder group at appropriate points in future rate design work, assuming the required commitment of time is reasonable. Education, issue identification, and consensus-building were mentioned as likely objectives of such a group.

This report will summarize each issue and provide tentative answers, concluding with sequences suggested by stakeholders for addressing them. As is often the case with stakeholder consultation, there was not proportional representation by customer class. The reader should consider the inherent interests of those stakeholders and the results—especially the quantitative ones—with that context in mind.

II. Rate Design Objectives

Throughout the workshops, stakeholders acknowledged that there was a broad need to make sure that rate designs were consistent with the principles laid out by Professor James Bonbright in his seminal work, *Principles of Public Utility Rates*. First published in 1961, the Bonbright principles for public utility rates have persisted through the decades and remain the most widely accepted ratemaking principles. They can be distilled into the five key criteria shown in Figure 1.

Figure 1: Bonbright's Principles of Ratemaking

Key Criterion	Bonbright Principle
I. Economic Efficiency	Static efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use
	Reflection of all of the present and future private and social costs and benefits occasioned by a service's provision (i.e., all internalities and externalities)
	Dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns
II. Equity	Fairness of the specified rates in the approportionment of total costs of service among the different ratepayers so as to avoid arbitrariness and capriciousness and to attain equity
	Avoidance of undue discrimination in rate relationships so as to be, if possible, compensatory
III. Revenue Stability	Effectiveness in yielding total revenue requirements under the fair-return standard without any socially undesirable expansion of the rate base or socially undesirable level of product quality and safety
	Revenue stability and predictability, with a minimum of unexpected changes that are seriously adverse to utility companies
IV. Bill Stability	Stability and predictability of the rates themselves, with a minimum of unexpected changes that are seriously adverse to utility customers and with a sense of historical continuity
V. Customer Satisfaction	The related, practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application
	Freedom from controversies as to proper interpretation

The economic efficiency criterion requires that the price of electricity reflect the underlying cost structure of producing and delivering electricity, ensuring that resources cannot be reallocated without making at least one consumer or producer worse off and resulting in an overall loss to society. In other words, no resources consumed in the delivery of electricity should be wasted.

The equity criterion refers to the need to ensure fairness both between customers and between the utility and the customers. Although rate design nearly always involves some degree of cross-subsidy, a utility should aim to remove unintentional subsidies between customer types. According to Bonbright, a natural way to achieve equity between customers with different load profiles and consumption values is through cost-reflective rates. Under such rates, customers who incur high costs for the system will pay proportionally higher amounts than low-cost customers.

The revenue stability criterion refers to the utility's ability to recover its costs through a sufficient and predictable level of revenues. The bill stability criterion stipulates that while the utility must recover its costs, ideally through cost-reflective rates, it must also protect customers from unmanageable fluctuations in their bills. Although new rates will nearly always result in bill increases for some customers, utilities can take steps to minimize seriously adverse and unexpected impacts, for instance by gradually implementing changes to rates over several years.

Finally, the customer satisfaction criterion brings out the central role customers play in the successful implementation of any changes to pricing structure. If not properly explained or rolled out, even simple rates can cause confusion and subsequently backlash from customers. Regulators and utility companies who anticipate such an adverse reaction from customers will resist implementing new rates.

One stakeholder voiced concerns that these five criteria do not capture the environmental effects of energy consumption. However, to the extent that environmental effects can be quantified, they can be included in the assessment of economic efficiency if prices reflect marginal costs.

A. Stakeholders' Preferred Rate Design Objectives

In order to understand the diverse priorities among stakeholders, we conducted a scorecard exercise at the first workshop to assess the relative importance of rate design objectives collected directly from stakeholders. In the first round, each organization designated a representative to share the objective they considered their top priority. Successive rounds then collected second and third priorities until a complete list of objectives had been compiled. At this point, each organization was given 100 points to allocate among all the rate design objectives. The scores were anonymized, and each participant filled out their own scorecards before seeing the aggregated results across all stakeholders. An illustrative completed scorecard (with a purely hypothetical point allocation) is presented below in Figure 2.

Figure 2: Illustrative Scorecard

Objective	Points
Accountability of Utility	0
Affordability	0
Bill Stability	20
Cost Reflectivity (Marginal Pricing)	0
Customer Education and Gradualism	20
Economic Efficiency	0
Environmental Sustainability and Conservation	0
Equity	40
Promotion of Public Benefits	10
Protection of Vulnerable Customers	10
Rate Choices	0
Revenue Recovery	0
Revenue Stability	0
Transparency to Customers	0
Total	***100***

Results of such scorecard exercises are not meant to yield a definitive ranking of issues. However, they can bring to light commonalities and differences between stakeholder groups. Initial results from the scorecard exercise were used to guide group discussions.

Figure 3 shows the total points allocated to each of the objectives by summing over all the stakeholders who participated in the voting, without any adjustments. Equity came in first with 268 points, followed by cost reflectivity with 175 points. At the other end were bill stability, environmental sustainability and conservation, and revenue stability.

Figure 3: Total Points Allocated to Rate Design Objectives

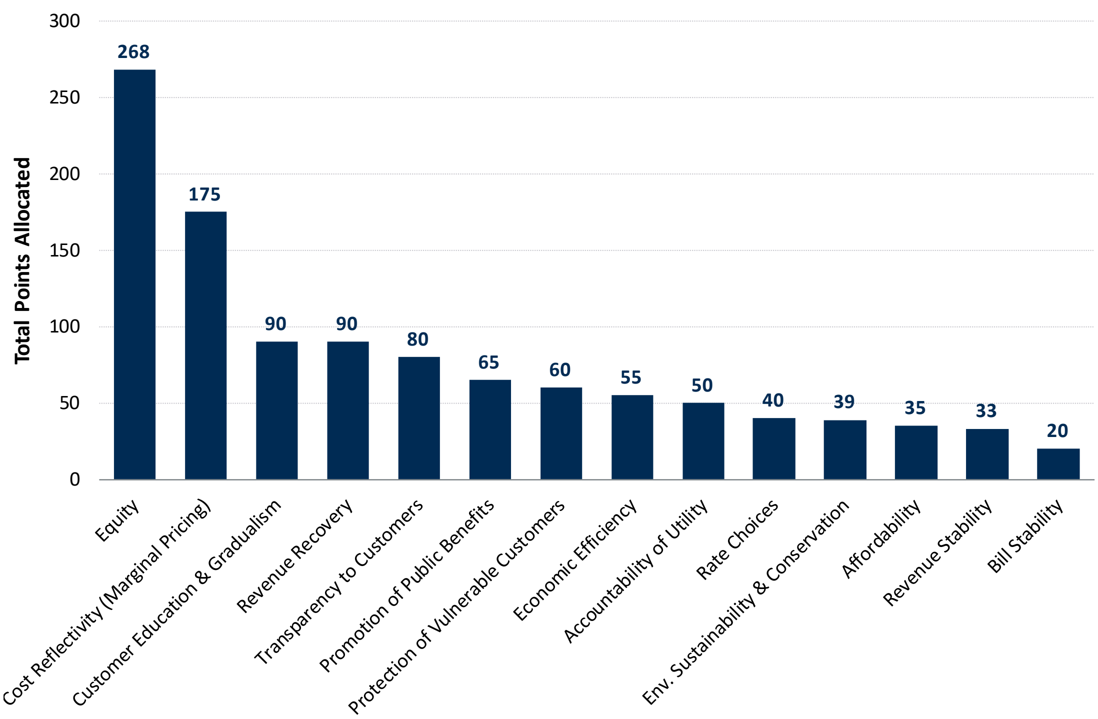
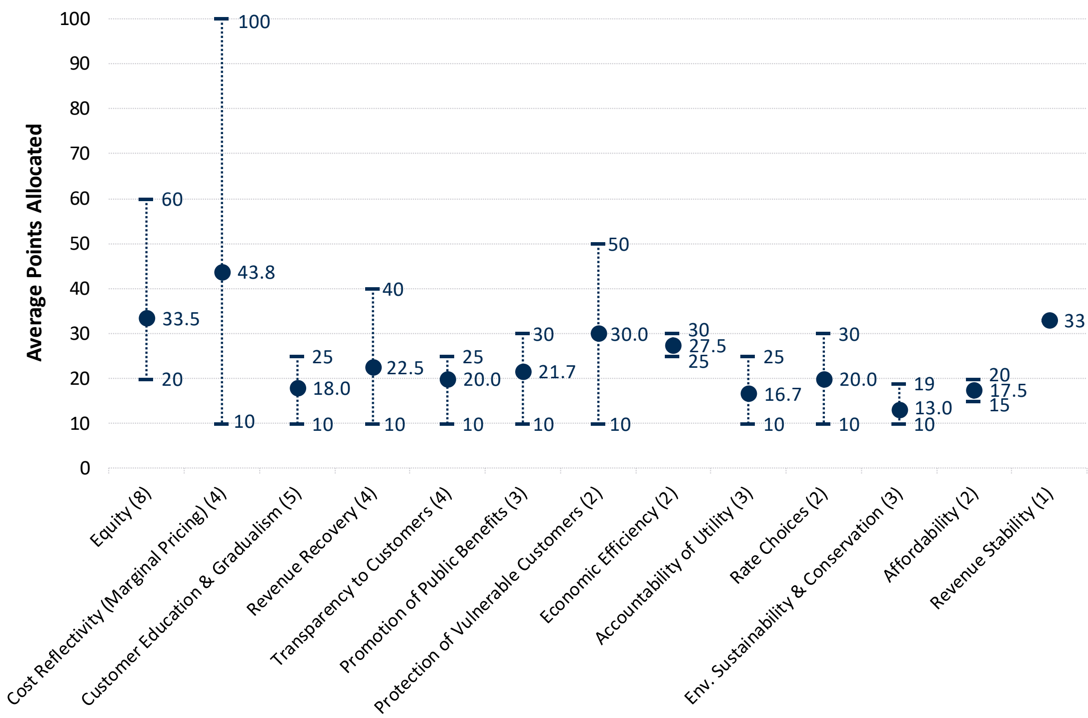


Figure 4 displays the distribution and range of points awarded to each of the fourteen objectives. Some parties differed significantly in their assessment of objective importance, but most respondents valued more than a single objective.

Figure 4: Distribution of Points Allocated to Rate Design Objectives



Notes: Scorecard results for 11 respondents. Lines represent min, average, and maximum number of points allocated to each rate design, calculated over all non-zero responses. (Numbers) in x-axis labels indicate the number of non-zero responses.

B. Stakeholders' Proposed Rate Designs to Achieve Objectives

Through the same process, stakeholders were asked in the first workshop to identify their preferred rate designs for achieving their stated rate design objectives, and then to vote on each of the rate designs that were identified through the process.[4] Seasonality in rates and time-of-use (TOU) rates ranked at the top, with total points allocated to "Seasonality in Rates" exceeding the next three highest ranking categories combined, while demand charges and dynamic pricing ranked at the bottom. However, it should be noted for all rate design scorecard exercises that while participants voted on individual rate options, many of these rate designs are not mutually exclusive and could be offered in combination. In addition, multiple stakeholders emphasized that while they were

[4] It should be noted that while all stakeholders present at the first workshop voted on their preferred objectives, some stakeholders (including the Board Staff) chose not to participate in one or more of the rate design scorecard exercises.

voting based on information available to them at the time of each scorecard exercise, renewed load research was needed to support and potentially alter their stated preferences.

Figure 5: Total Points Allocated to Rate Designs

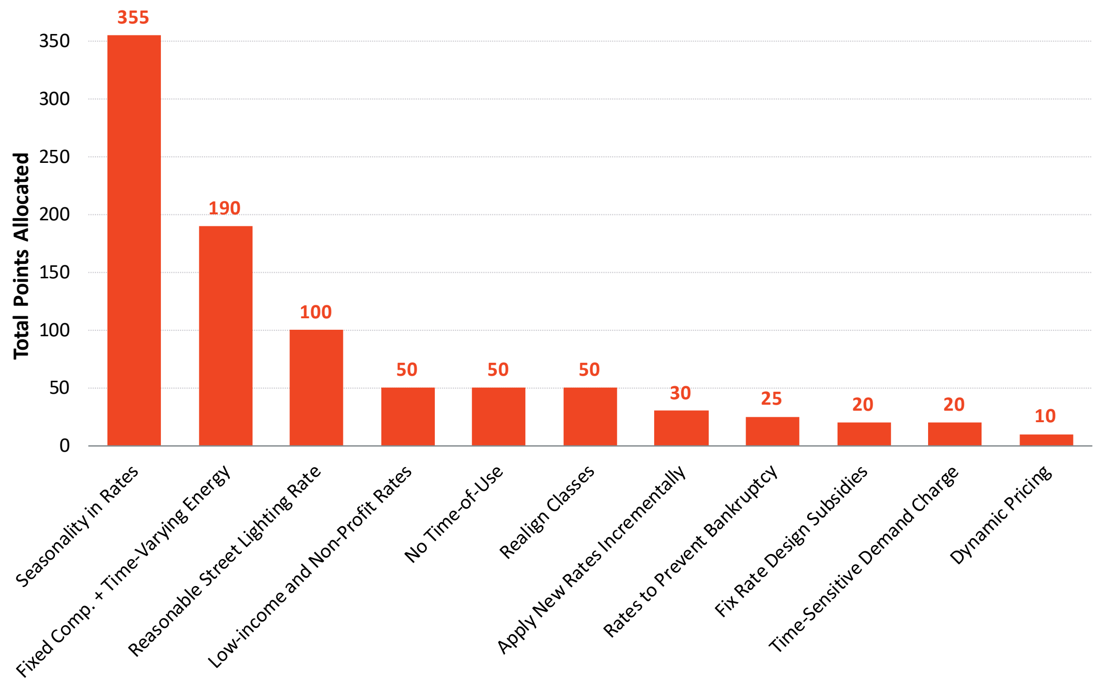
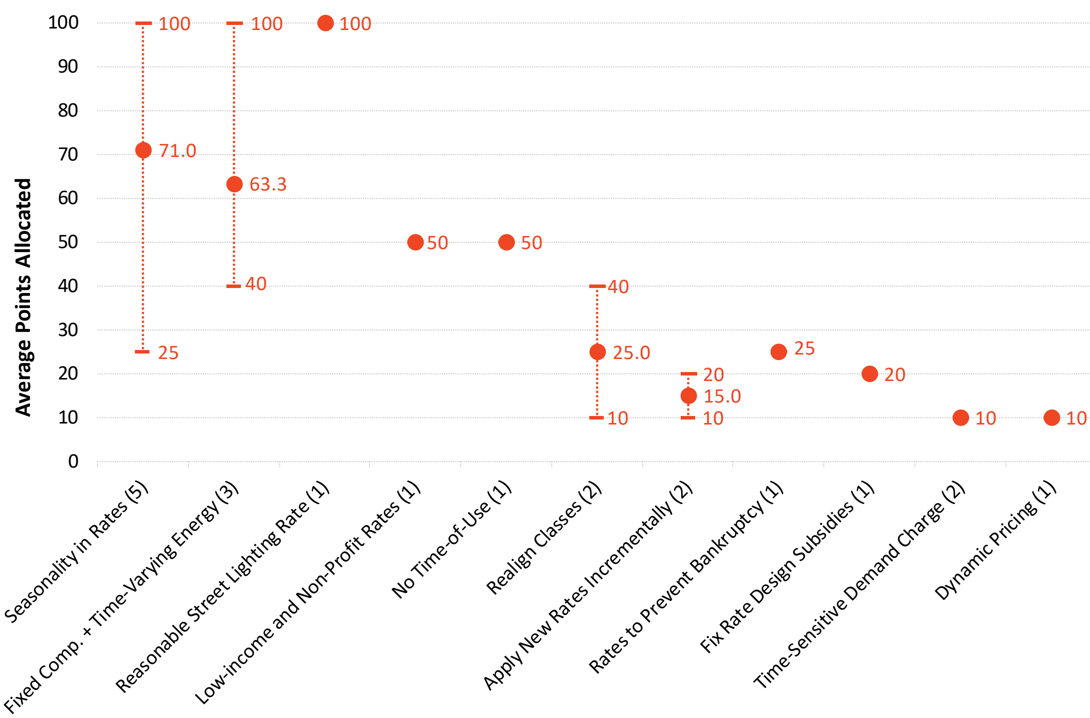


Figure 6: Distribution of Points Allocated to Rate Designs



Notes: Scorecard results for 9 respondents. Two stakeholders present at the workshop chose to abstain.

III. Preferred Rate Design Options

NB Power currently serves all residential customers[5] under a two-part tariff consisting of a monthly service charge and a volumetric energy charge expressed in cents per kilowatt-hours.[6] Rural and seasonal customers pay the same energy charge as urban customers, but a slightly higher service charge. Business customers are predominantly served under General Service and Industrial tariffs that have a demand charge but no time-varying component.[7]

Discussion of rate design was predominantly focused on the Residential rate class. A minority of stakeholders was satisfied with the current two-part residential tariff, while most of the stakeholders recognized that truly determining the most suitable rates would require additional customer load and utility cost data and analysis. However, following discussions about rate design options available both without and with AMI, a few rate designs emerged at the second workshop as leading contenders for NB Power and the Board to consider.

Assessing the appropriateness of AMI was deemed to be outside the scope of the stakeholder sessions, leading to the separate discussion of rates available without AMI and those that are only available with AMI. That discussion did not identify which of the options that can be implemented without AMI should not be pursued if a decision is made to proceed with AMI. The impending decision on if and when AMI proceeds will facilitate a more deliberate discussion on which of the options should be considered for implementation.

A. Rate Design Options without AMI

1. Traditional Two-Part Rate (Current Rate)

Like NB Power, most utilities currently serve residential customers on two-part rates consisting of a fixed monthly charge and a volumetric ¢/kWh energy charge. Such rates typically recover most of the costs on a volumetric basis, building non-variable fixed and capacity costs into the energy charge using assumptions about class load factors. If cost-justified, many jurisdictions with

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5 In addition to customers using electricity for living purposes, NB Power's Residential class includes farms, churches, non-church religious and charitable institutions taking service prior to 29 August 1979, and eligible boarding houses and combined dwelling/business operations. For a full definition, see NB Power, "RSP N-2: Rate Schedules and Policies Manual," accessed at https://www.nbpower.com/en/about-us/divisions/customer-service/policies/rspn2/.

6 NB Power, "Residential Rates (effective July 18, 2019)," accessed at https://www.nbpower.com/en/products-services/residential/rates

7 The General Service tariffs consist of a monthly service charge, a demand charge for peak demands in excess of 20 kW, and a two-step declining block energy charge (to reflect the absence of a demand charge up to 20 kW). The Small Industrial tariff consists of a demand charge and a two-block load factor energy ("Wright") charge. The Large Industrial and Wholesale tariffs consist of an energy charge and a demand charge.

traditional two-part rate designs have a seasonal differential reflecting the higher costs of serving the higher cost season

2. Block Rates

Block rate structures, which have historically been the most common deviation from traditional two-part rates, charge customers different prices for different blocks or tiers of usage. A justification for either an inclining or declining block rate structure is it provides the utility with the ability to establish the tail-block as a cost-reflective (marginal) price signal that differs from the average revenue requirement. The approach is often justified when a significant difference exists between the embedded revenue requirement of the utility and the marginal cost, or when constraints in cost allocation shift costs from one customer group to another. However, block rate structures have been found to be confusing by many customers and are either being phased out or flattened in several North American jurisdictions.

Under a declining block rate, the ¢/kWh rate is lower at higher usage tiers, reflecting an economic environment in which unit electricity costs were declining over time. In today's environment, however, this design is unpopular with conservation advocates who see it as encouraging excessive consumption. Similarly, solar advocates often see this design as decreasing the economic incentives for solar, since distributed generation (DG) customers would be offsetting their usage at the higher, cheaper tiers, and placing them in lower, more expensive tiers.

As a result, declining block rates are now less common than inclining block rates, which can send stronger conservation signals than traditional flat, two-part rates by charging an increasing ¢/kWh rate for increasing kWh usage tiers. Inclining block rates are also popular with low-income advocates, since low-income customers on average tend to be lower-usage, but less so with advocates of electrification that is intended to promote higher electricity usage. Inclining block rates can be cost-reflective in certain circumstances, such as when the cost of new capacity exceeds embedded costs, or when larger customers have lower load factors than smaller customers due to large weather-sensitive loads.

3. Seasonal Rates

Seasonal rates are the simplest form of time-varying rates, in that they include higher charges during the peak season and lower charges during the off-peak season to better align prices with costs and bring them into conformity with the Bonbright principle of cost causation. For example, a winter-peaking utility could better capture both higher energy and capacity costs associated with serving winter loads by setting higher energy charges in the winter than in the summer when costs are lower. Seasonal rates have the benefit of being relatively simple and understandable to customers, and can be combined with other rate designs like block rates to convey stronger price signals. They have been implemented by utilities with non-AMI technology for over 40 years.

4. Optional Time-of-Day (TOU) Rates

Although seasonal rates are the most common form of time-varying rates available without AMI, it is possible to offer optional time-of-day rates even without smart meters. Time-of-day rates, which can be implemented in conjunction with seasonal rates, are a form of TOU rate[8] in which different charges apply at different times of day. Typically, TOU rates refer to rate designs with pre-set charges for fixed on-peak and off-peak periods during the day, with both the magnitude of the charges and the definition of pricing periods being allowed to vary by season.[9] TOU rates can promote cost-effective load-shifting and mitigate cross-subsidies between customers under two-part volumetric tariffs by better capturing the cost variation in supplying electricity across different times of day. However, implementing time-of-day TOU rates requires the installation of interval meters that can record usage during the pre-set periods. Thus, without AMI, TOU rates would only be optional for those customers who choose to have the necessary metering installed.

5. Optional Demand Charges

Demand charges, which have long been the norm for medium and large non-residential customers, can be offered to customers with special meters. In the absence of AMI and TOU rates, demand charges provide an alternative for billing customers according to their usage patterns. At a minimum, non-coincident demand charges can recover distribution system costs and serve as a proxy for customer's connected load. If customers' demand aligns with the system peak, demand charges based on coincident peak loads can further encourage customers to shift their usage to periods with cheaper energy.

6. Fixed Monthly Bills

NB Power currently offers equalized billing, under which eligible customers pay equal amounts across all months but then must pay the difference between the equalized amounts and actual total charges at year end. As an enhancement on equalized or levelized billing, some utilities now offer fixed monthly billing, which smooths out the expected annual bill into predictable, flat monthly payments without any true-up at the end of the year. The expected annual bill is typically computed based on historical usage, plus a % risk adder, and then split evenly into twelve monthly payments. This rate design is often called a subscription plan.

If a customer's usage deviates too much from their historical and expected usage, the utility may offer to them the option of reverting back to the standard tariff or offer another fixed monthly billing plan with a higher amount. This concept provides customers a guaranteed fixed bill, which provides certainty to more risk-averse customers and gets rid of any weather-related fluctuations

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8 Seasonal rates are technically considered time-of-use rates. However, for simplicity, we use "TOU rates" to refer to time-of-day TOU rates throughout this report.

9 The pre-set charges and fixed periods distinguish TOU rates from dynamic real-time pricing rates discussed below.

and bill surprises. This can especially be helpful to low-income customers in helping them plan and guaranteeing them more control over their bill.

7. Results of Scorecard Exercise for Rates without AMI

Seasonal rates emerged as the leading rate design without AMI through the scorecard exercise at the second workshop, consistent with the first workshop results. The results are shown in Figure 7 and the dispersion in the scores is shown in Figure 8.

Figure 7: Total Points Allocated to Rate Designs without AMI

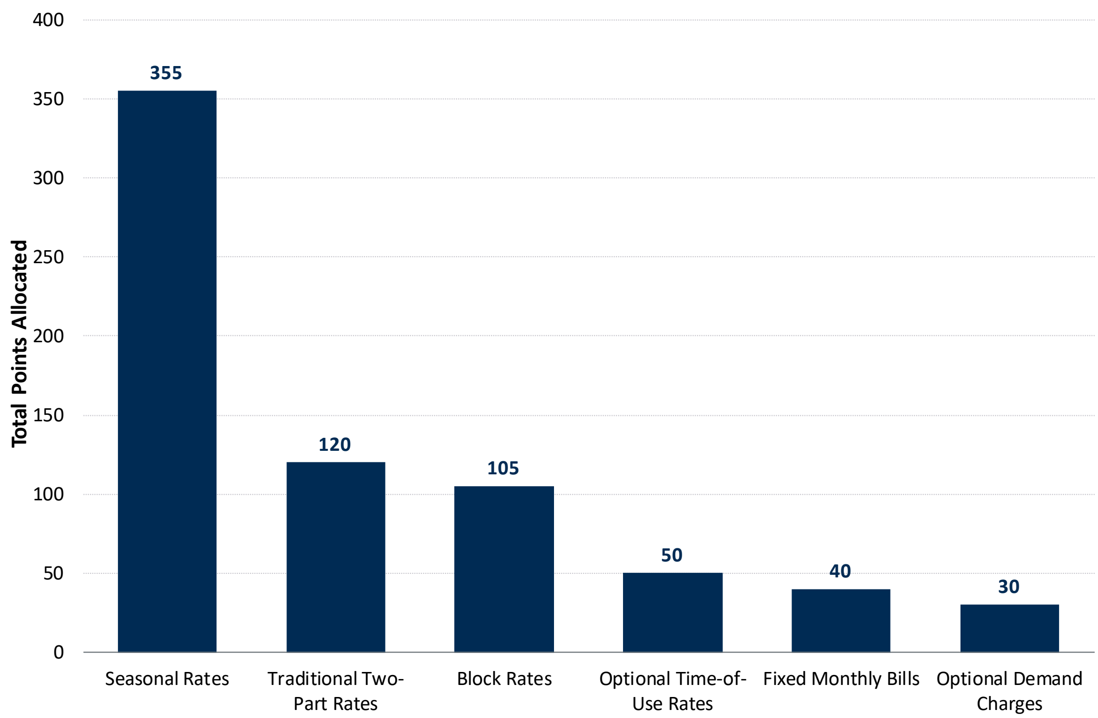
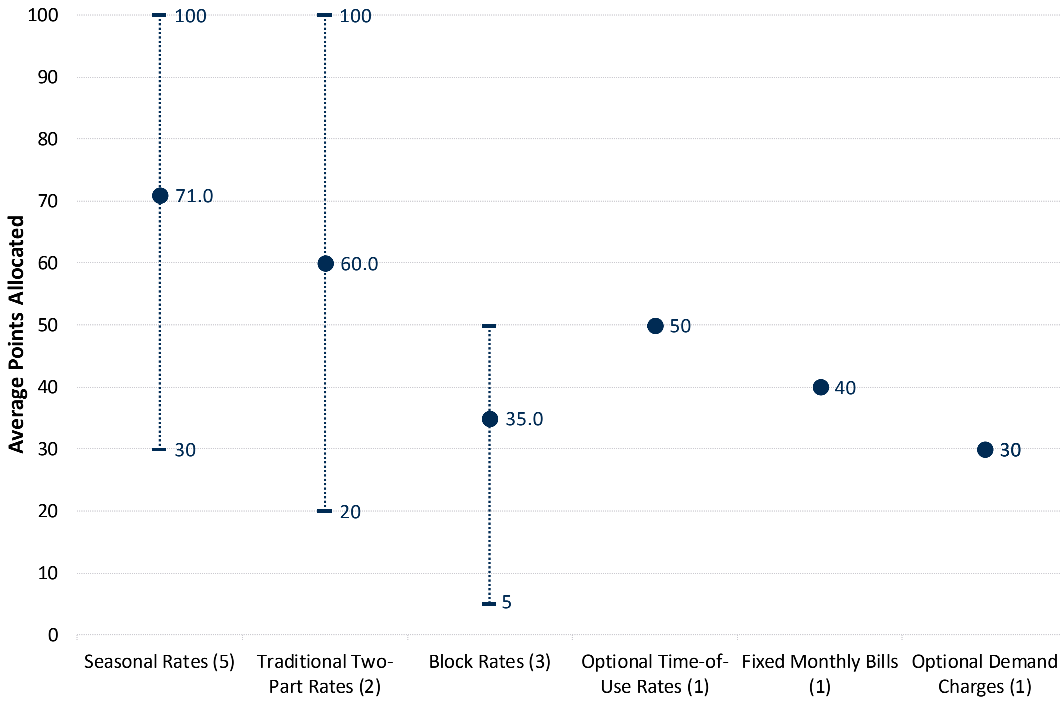


Figure 8: Distribution of Points Allocated to Rate Designs without AMI



Notes: Scorecard results for 7 respondents. Three stakeholders present at the workshop chose to abstain.

B. Rate Design Options with AMI

AMI is not currently deployed under NB Power's service territory. AMI can significantly enhance the options for the future of rate design. Given technological advancements in the last decades, meters that were once available only to commercial and industrial customers are now much more affordable and accessible, and thus available to the mass market. Smart meter penetration in North America has reached 60%, and according to a recent Berg Insight report is projected to grow to over 80% in the next five years.[10] That growth has applied to Canada, where British Columbia, Ontario, and Quebec have deployed AMI, while Nova Scotia is currently in the process of deploying it to all its customers.[11]

NB Power has filed an AMI application with the Board in a separate proceeding.[12] While this report makes no recommendation on the deployment of AMI, given that a majority of all North American electric meters are now smart meters, it is useful to review modern rates being deployed in other jurisdictions with AMI.

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10 Berg Insight, "Smart Metering in North America and Asia-Pacific," accessed at http://www.berginsight.com/ReportPDF/ProductSheet/bi-smnaap2-ps.pdf.

11 A few stakeholders expressed strong disagreement with the adoption of the specific AMI technology that is currently proposed by NB Power, and thus similarly opposed any rate designs that rely on the widespread adoption of that technology.

12 *See* NBEUB Matter 452.

1. Modern Rate Options

Beyond the existing options discussed above, AMI allows utilities to offer other more cost-reflective rates like those defined below in Table 1 on a more cost-effective or widespread basis.[13]

Table 1: Modern Rate Options Available with AMI

Rate	Definition
Time-of-use (TOU) Rate	The day is divided into time periods which define peak and off-peak hours. Prices are higher during the peak period hours to reflect the higher cost of supplying energy during that period.
Demand Charge	Customers are charged based on peak electricity consumption, typically over a span of 15, 30, or 60 minutes.
Critical Peak Pricing (CPP)	Customers pay higher prices during critical events when system costs are highest or when the power grid is severely stressed.
Peak Time Rebate (PTR)	Customers are paid for load reductions on critical days, estimated relative to a forecast of what the customer would have otherwise consumed (their "baseline").
Real-Time Pricing (RTP)	Customers pay prices that vary by the hour to reflect the actual cost of electricity in each hour.

2. Results of Scorecard Exercise for Rates with AMI

Assuming AMI is in place, there was convergence in both the scorecard exercise and ensuing discussions that more economically efficient time-varying rates should be explored as the best option for achieving stakeholders' stated goals. There was strong support from two stakeholders for non-AMI rates other than the current rate. The results are shown in Figure 9 and Figure 10. Some of the rates shown in the figures can be combined. They are not mutually exclusive.

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13 It should be noted that TOU and demand charges can be implemented without AMI. For example, in the 1980s Illinois Power Company (now part of Ameren) implemented a TOU tariff with explicit demand charges and energy charges differentiated by TOU using conventional metering technology.

Figure 9: Total Points Allocated to Rate Designs with AMI

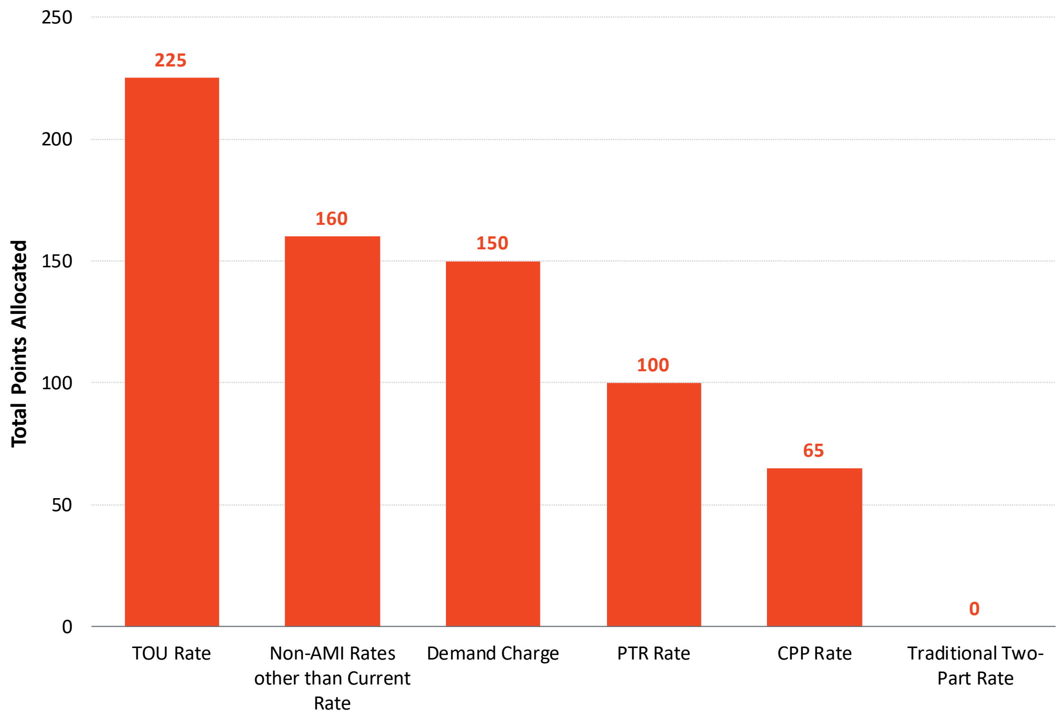
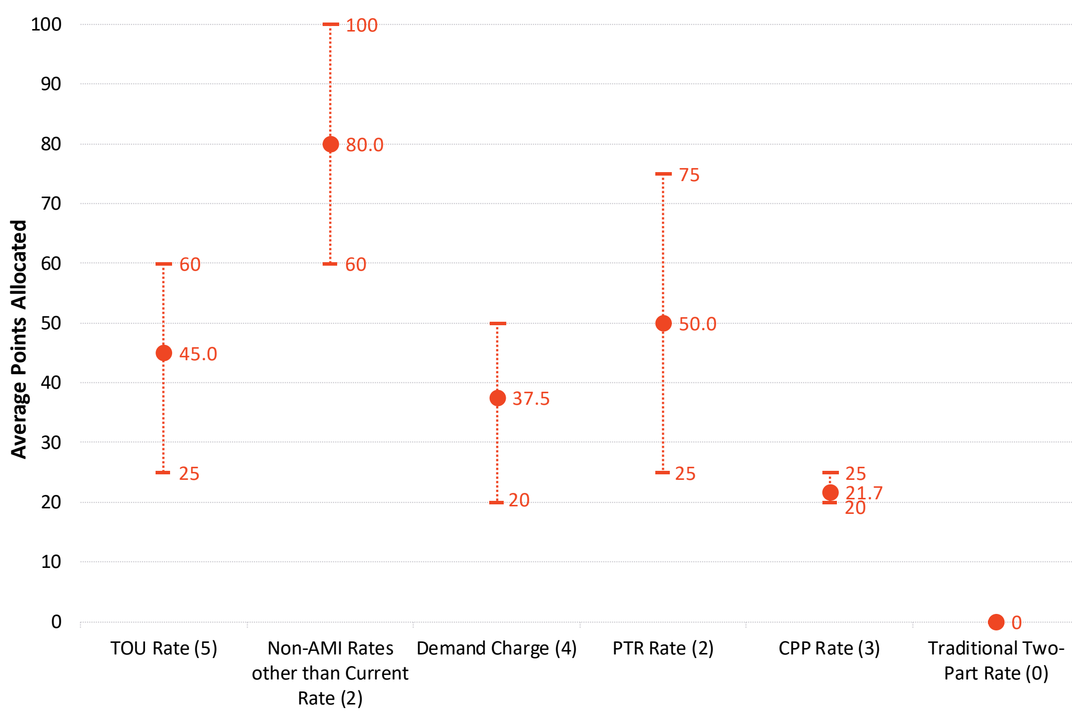


Figure 10: Distribution of Points Allocated to Rate Designs with AMI



Notes: Scorecard results for 7 respondents. Three stakeholders present at the workshop chose to abstain.

IV. Jurisdictional Scan

This section includes a survey of rate designs across multiple jurisdictions.

A. Modern rates being offered in other Jurisdictions

Residential customers are now being exposed to more cost-reflective tariff options that previously were available only to large C&I customers. Several examples are included in Table 2 below.

Table 2: Jurisdictions Offering Modern Rates to Residential Customers

	Mandatory	Opt-in	Opt-out
Time-of-use (TOU) volumetric rates	Fort Collins (Colorado)	Texas	SMUD (California), Ontario, *Michigan*, California**
Demand Charges		Arizona Public Service, Black Hills, Salt River Project	
Peak Time Rebates		Oregon, Illinois	Maryland, California
Other dynamic volumetric rates (CPP, RTP)		Oklahoma, Illinois	California IOUs

Notes: *Consumers Energy in Michigan and Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric in California are moving all their residential customers to TOU rates in 2020.

While TOU rates were introduced decades ago, they are now becoming increasingly widespread with the emergence of AMI, and over fourteen percent of all U.S. utilities (including roughly half of all investor-owned utilities) now offer a residential TOU rate.[14] Most notably, soon after its province-wide rollout of smart meters, Ontario introduced default TOU rates with off-peak, mid-peak, and on-peak prices defined by season for residential and small commercial customers. Similarly, the Sacramento Municipal Utility District (SMUD) has begun moving all its residential customers to default TOU rates, while Fort Collins in Colorado has moved all of their residential customers to TOU rates on a mandatory basis.[15]

Among these TOU rates, six percent now include a demand charge on top of the time-varying volumetric charge. Leading the adoption of TOU and demand charges in the U.S. is Arizona Public Service (APS). Approximately fifty-seven percent of APS's residential customers are enrolled in TOU rates, and twenty-percent of these customers pay a demand charge. To ease the transition since it first implemented demand charges in 1989, APS made a significant commitment to provide customers with information on the various rate options. Ultimately, this resulted in a rate

14 Ryan Hledik, Cody Warner, and Ahmad Faruqui, "Status of Residential Time-of-Use Rates in the U.S," *Public Utilities Fortnightly* (November 2018).

15 SMUD and Fort Collins had 557,352 and 65,303 residential customers respectively as of 2018, according to data from Form EIA-861.

comparison tool that customers either could use on their own or with the assistance of a customer service representative. Additionally, APS began to provide customers with an annual analysis of their usage, energy savings recommendations, and a rate recommendation if the customer would benefit from switching. The company also provides rate comparisons for customers who contact the call center. As APS began rolling out more advanced metering to all customers, the rate comparison tool was modified to reflect analysis of actual load data. Over the years, APS has not marketed any particular rate option to its customers. Instead, it has provided them—through the rate comparison tool—the information they need to make an informed decision about what rates are best for them.

APS is not alone in introducing demand charges for residential customers. At least 62 demand charges are now being offered in some 24 states by some 51 utilities. Demand charges tend to be disproportionately prevalent among cooperatives, which are owned by the customers they serve and thus have an additional responsibility to guarantee equity among members. Some cooperatives have even implemented mandatory demand charges for certain customers. For example, the Salt River Project has mandatory demand charges for customers with rooftop solar panels.

Additionally, Peak Time Rebates (PTR) are now being offered by utilities in Maryland, California, Illinois, and Oregon. PTR rates are in many ways a mirror image of CPP rates, which expose customers to higher prices during periods of high demand, by instead offering customers a rebate in these peak periods for consuming less than what they would have without the declaration of a critical peak. As a result, some stakeholders noted that PTR rates would likely be easier to market to customers.

Successful dynamic pricing programs are often supported by smart technologies. In 2012, Oklahoma Gas & Electric rolled out its SmartHours program, a dynamic pricing program offered to residential customers on an opt-in basis. As part of the program, the utility offers its customers the option to install smart thermostats, which will adjust in response to price signals according to customers' programmed preferences. However, customers maintain full control, so they can override these settings and choose not to respond to OG&E's alerts. A fifth of customers have signed up for SmartHours and achieved significant savings on their electric bills.

While typically reserved for commercial customers, Real-Time Pricing (RTP) is now being offered to residential customers in Illinois by both Ameren Power Illinois and ComEd. The Commission approved both utilities' AMI business case contingent on customer engagement, enabling customers to access online energy-management tools and view their hourly usage from the prior day. Under these programs, prices vary hourly according to wholesale market prices.

Although adoption rates for dynamic pricing tariffs remain low, the successes of a few utilities and the growing prevalence of TOU rates (as shown below in Table 3) show promise for customer willingness to adopt future tariffs.

Table 3: Adoption of Modern Residential Rates in Other Jurisdictions

Utility or Location	Type of Rate	Applicability	Participating Customers
Arizona (APS)	Three-Part rate	Opt-in	20% of APS' residential customers
Georgia (GPC)	Fixed bill	Opt-in	14% (290,000)
California (PG&E, SCE, SDG&E)	Time-of-Use (TOU)	Default (2019)	TBD—75–90%*
Colorado (Fort Collins)	Time-of-Use (TOU)	Mandatory (for residential)	100%
Illinois (ComEd, Ameren Power Illinois)	Real Time Pricing (RTP)	Opt-in	50,000
Maryland (BGE, Pepco, Delmarva)	Dynamic Peak Time Rebate (PTR)	Default	80%
Oklahoma (OGE)	Variable Peak Pricing (VPP)	Opt-in	20% (130,000)
Ontario, Canada (several)	Time-of-Use (TOU)	Default	90% (3.6 million)
France	Time-of-Use (TOU)	Opt-in	50%
Spain	Real Time Pricing (RTP)	Default	50%
Italy	Time-of-Use (TOU)	Default	75–90%*

Notes: *Estimated participation based on historical trends

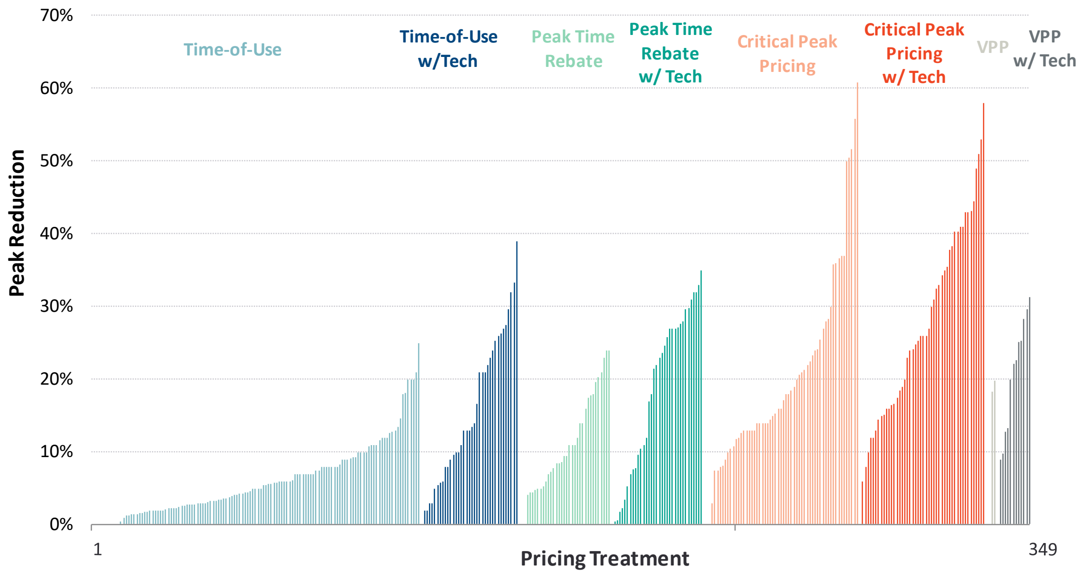
Finally, fixed monthly bills (or flat bills) are popular in a number of states including the Carolinas, Florida, Georgia, Indiana, and Oklahoma, and are being considered by several utilities around the country.

B. Customer Response to Modern Rates

Evidence from nearly 350 deployments worldwide shows that customers respond to time-varying rates, and that their price response is boosted with enabling technology.[16] Figure 11 plots the peak reductions modeled in these deployments with and without enabling technology, grouped by the form of time-varying rate.

[16] *See* Ahmad Faruqui, Sanem Sergici, and Cody Warner, "*Arcturus* 2:0: A meta-analysis of time-varying rates for electricity," *The Electricity Journal* 30 (2017): 64–72.

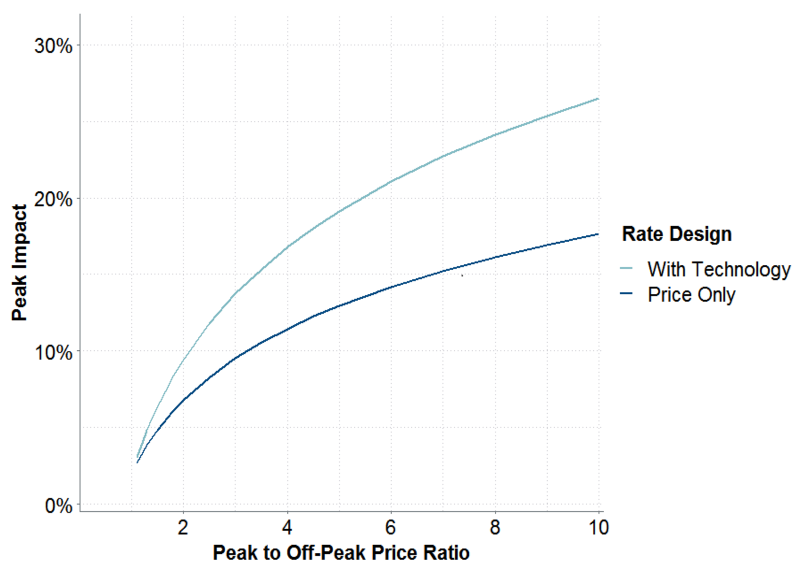
Figure 11: Peak Reductions from Time-Varying Pilots



Source: Results of 349 pricing pilots collected in the Arcturus 2.0 database.

An econometric analysis of these pilot results yields a clear and statistically significant relationship between the strength of the price signal and the magnitude of customer response. When paired with enabling technology, such as smart thermostats or in-home displays, the customer price response is even stronger. The price responsive behavior of customers on time-varying rates yields an arc of price response, shown in Figure 12 below.

Figure 12: Modeled Peak Impact under Time-Varying Rates



The arc of price response reveals that customers respond to higher peak to off-peak ratios by lowering their peak demand, though at a diminishing rate. In the absence of enabling technologies like smart thermostats, the reduction in peak demand is roughly 6% under a 2:1 price ratio, compared to over 10% when the price ratio doubles to 4:1. The reduction in peak demand under a 4:1 ratio rises to 25% when abetted by smart technology.

V. Next Steps in Rate Design

Given discussions with stakeholders in this Matter and results from the first two workshops, the following issues have been identified as important next steps:

1. Carry out load research
2. Review and conduct cost of service study
3. Consider customer classification based on nature of load
4. Consider classification of charitable organizations
5. Consider appropriateness of separate Small Industrial and GS tariffs
6. Review street lighting rates
7. Address cross-subsidization of heating customers
8. Consider concessions for vulnerable customers
9. Address GS I and Residential rate class inequities
10. Analyze the impact of new rates on customer bills
11. Consider introducing seasonal rates
12. Consider introducing opt-in TOU rates
13. Consider introducing opt-in fully-hedged bills
14. Design and implement rate design pilots
15. Model rate switching behavior of customers
16. Plan and implement transition to new rates
17. Consider introducing default TOU rates
18. Consider introducing dynamic pricing
19. Consider introducing residential demand charge

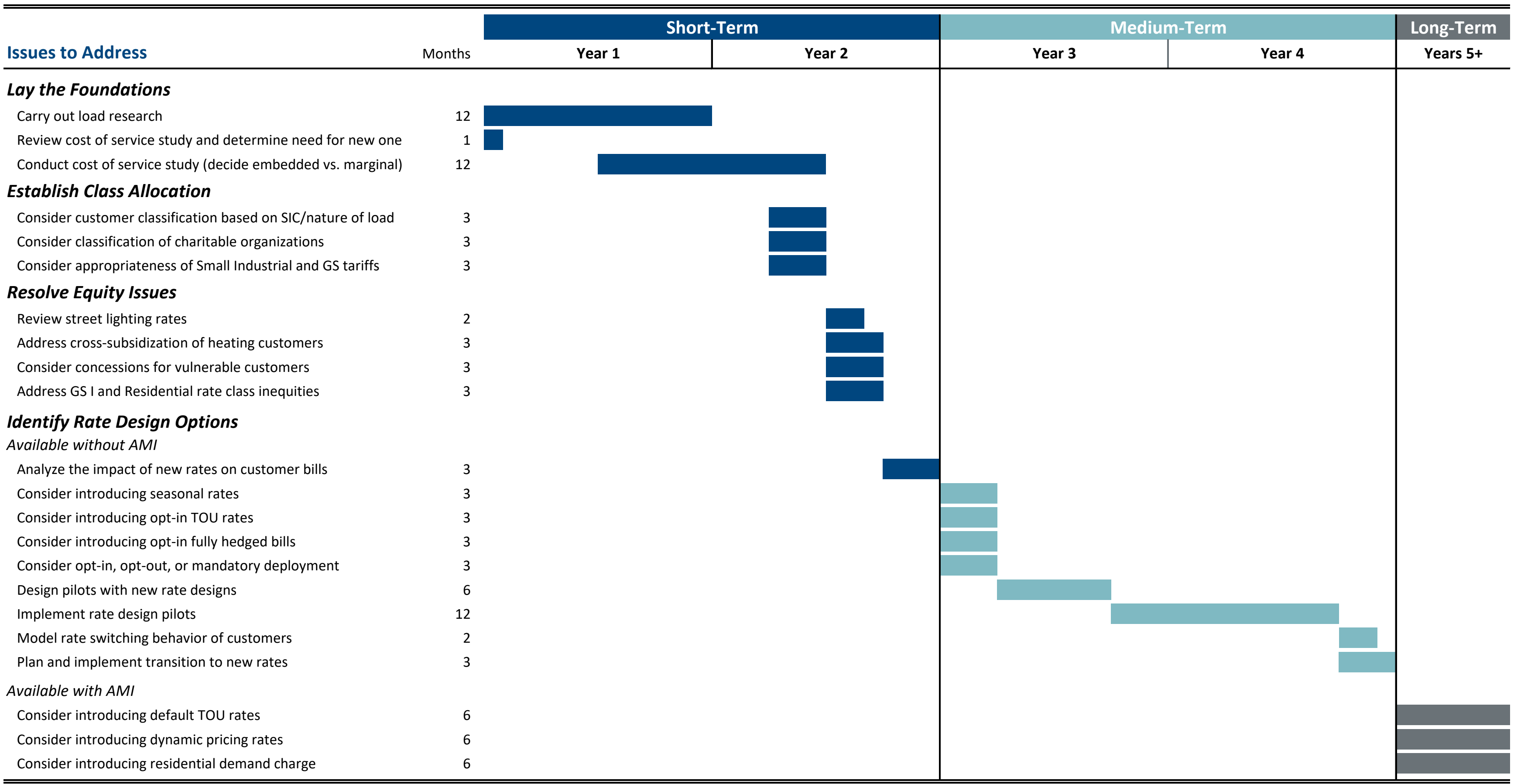
These issues could be sequenced many different ways. Some decisions will inevitably influence the feasibility and scheduling of others, while others are contingent on outcomes beyond the scope of this Matter. Based on both stakeholder input throughout the first two workshops and previous rate design experience with other jurisdictions, Brattle initially laid out a suggested sequencing of activities to serve as a catalyst for discussion during the third workshop. During the third workshop, all participants were invited to complete their own suggested sequencing chart, using a blank template that loosely assigned issues to three buckets: short-term (roughly years 1–2), medium-term (years 3–4), and long-term (years 5–10). These buckets were created by Brattle as a way to identify milestones and areas of convergence, and were not defined through group discussions. The start of Year 1 was left deliberately ambiguous, to account for differing stakeholder expectations and uncertainty as to the hearing timeline.

Six stakeholder organizations submitted charts, which are displayed in Figure 13 below. Note that two of the charts (Panels A and C) directly adopted Brattle's catalytic chart. All stakeholders acknowledged that their suggested sequencing is suggestive, and should not be taken literally since any forecast timeline would need to be continuously reviewed and refreshed as new information became available.

The sequencing charts were produced with limited time for stakeholder discussion of impacts on customers, customer education, and customer acceptance. Too many changes at the same time could pose a problem for NB Power, the Board, stakeholders, and customers. Similarly, charts were produced without an extensive examination of resource requirements and availability. Actual implementation of the activities identified in the charts will have to give due consideration to the impact of rate design changes on customer bills and the business, regulatory, and political realities. NB Power will need to plan its activities and make regulatory filings in a logical sequence with guidance from this report, in consideration of the priorities of customers, and in compliance with Board directives.

Figure 13: Proposed Sequencing of Issues

Panel A: Proposed Sequencing from Stakeholder 1



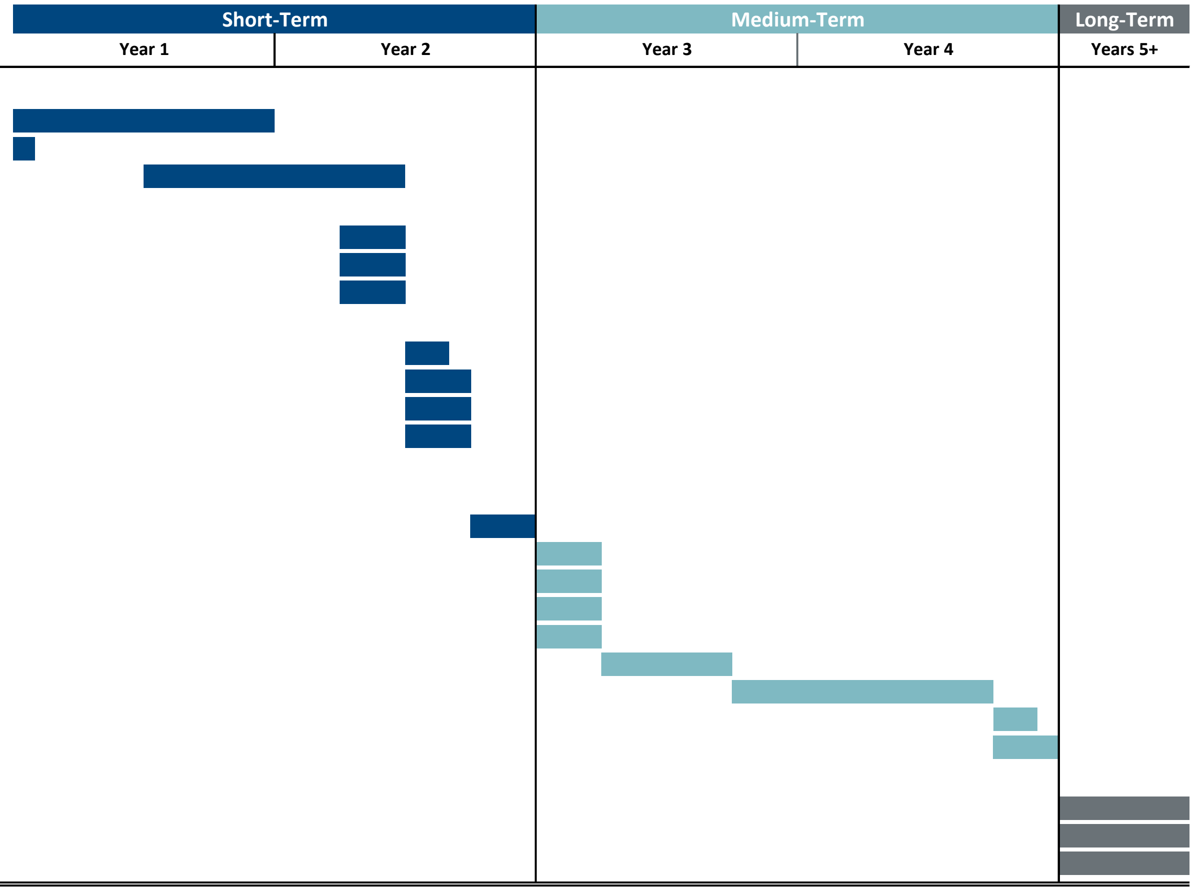
Notes: Stakeholder chose to adopt Brattle's catalytic chart.

Panel B: Proposed Sequencing from Stakeholder 2

Issues to Address	Months	Short-Term: Year 1	Short-Term: Year 2	Medium-Term: Year 3	Medium-Term: Year 4	Long-Term: Years 5+
Lay the Foundations						
Carry out load research	12					
Review cost of service study and determine need for new one	6					
Conduct cost of service study (decide embedded vs. marginal)	1					
Establish Class Allocation						
Consider customer classification based on SIC/nature of load	12					
Consider classification of charitable organizations	12					
Consider appropriateness of Small Industrial and GS tariffs	12					
Resolve Equity Issues						
Review street lighting rates	2					
Address cross-subsidization of heating customers	54					
Consider concessions for vulnerable customers	2					
Address GS I and Residential rate class inequities	54					
Identify Rate Design Options						
Available without AMI						
Analyze the impact of new rates on customer bills	54					
Consider introducing seasonal rates	6					
Consider introducing opt-in TOU rates	24					
Consider introducing opt-in fully hedged bills	0					
Consider opt-in, opt-out, or mandatory deployment	0					
Design pilots with new rate designs	42					
Implement rate design pilots	42					
Model rate switching behavior of customers	42					
Plan and implement transition to new rates	54					
Available with AMI						
Consider introducing default TOU rates	6					
Consider introducing dynamic pricing rates	6					
Consider introducing residential demand charge	6					

Panel C: Proposed Sequencing from Stakeholder 3

Issues to Address	Months
Lay the Foundations	
Carry out load research	12
Review cost of service study and determine need for new one	1
Conduct cost of service study (decide embedded vs. marginal)	12
Establish Class Allocation	
Consider customer classification based on SIC/nature of load	3
Consider classification of charitable organizations	3
Consider appropriateness of Small Industrial and GS tariffs	3
Resolve Equity Issues	
Review street lighting rates	2
Address cross-subsidization of heating customers	3
Consider concessions for vulnerable customers	3
Address GS I and Residential rate class inequities	3
Identify Rate Design Options	
Available without AMI	
Analyze the impact of new rates on customer bills	3
Consider introducing seasonal rates	3
Consider introducing opt-in TOU rates	3
Consider introducing opt-in fully hedged bills	3
Consider opt-in, opt-out, or mandatory deployment	3
Design pilots with new rate designs	6
Implement rate design pilots	12
Model rate switching behavior of customers	2
Plan and implement transition to new rates	3
Available with AMI	
Consider introducing default TOU rates	6
Consider introducing dynamic pricing rates	6
Consider introducing residential demand charge	6



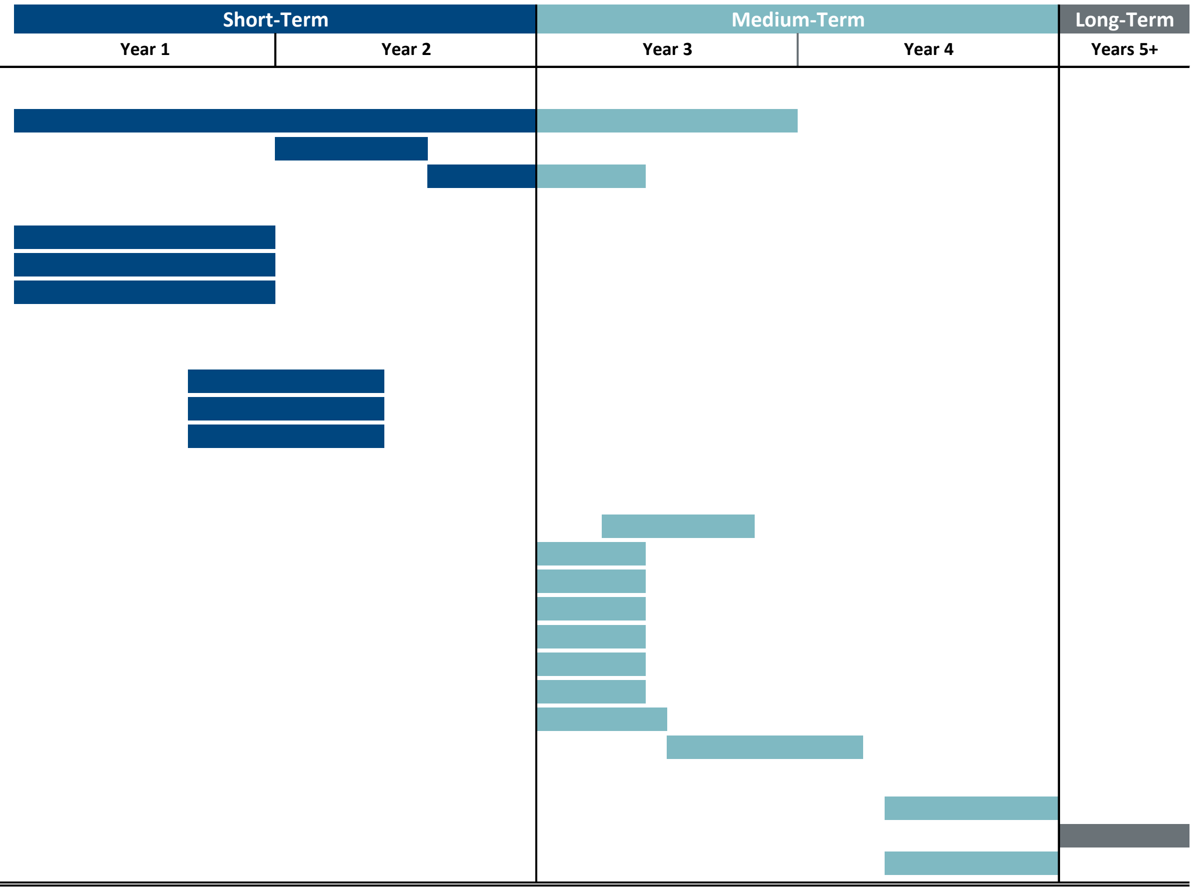
Notes: Stakeholder chose to adopt Brattle's catalytic chart.

Panel D: Proposed Sequencing from Stakeholder 4

		Short-Term		Medium-Term		Long-Term
Issues to Address	Months	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Years 5+**
Lay the Foundations						
Carry out load research	18					
Review cost of service study and determine need for new one	12					
Conduct cost of service study (decide embedded vs. marginal)	12					
Establish Class Allocation						
Consider customer classification based on SIC/nature of load	12					
Consider classification of charitable organizations	12					
Consider appropriateness of Small Industrial and GS tariffs	12					
Resolve Equity Issues						
Review street lighting rates	12					
Address cross-subsidization of heating customers	12					
Consider concessions for vulnerable customers	12					
Address GS I and Residential rate class inequities	12					
Identify Rate Design Options						
Available without AMI						
Analyze the impact of new rates on customer bills	12					
Consider introducing seasonal rates	14					
Consider introducing opt-in TOU rates	12					
Consider introducing opt-in fully hedged bills	12					
Consider opt-in, opt-out, or mandatory deployment	12					
Design pilots with new rate designs	12					
Implement rate design pilots	14					
Model rate switching behavior of customers	14					
Plan and implement transition to new rates	14					
Available with AMI						
Consider introducing default TOU rates	11					
Consider introducing dynamic pricing rates	11					
Consider introducing residential demand charge	11					

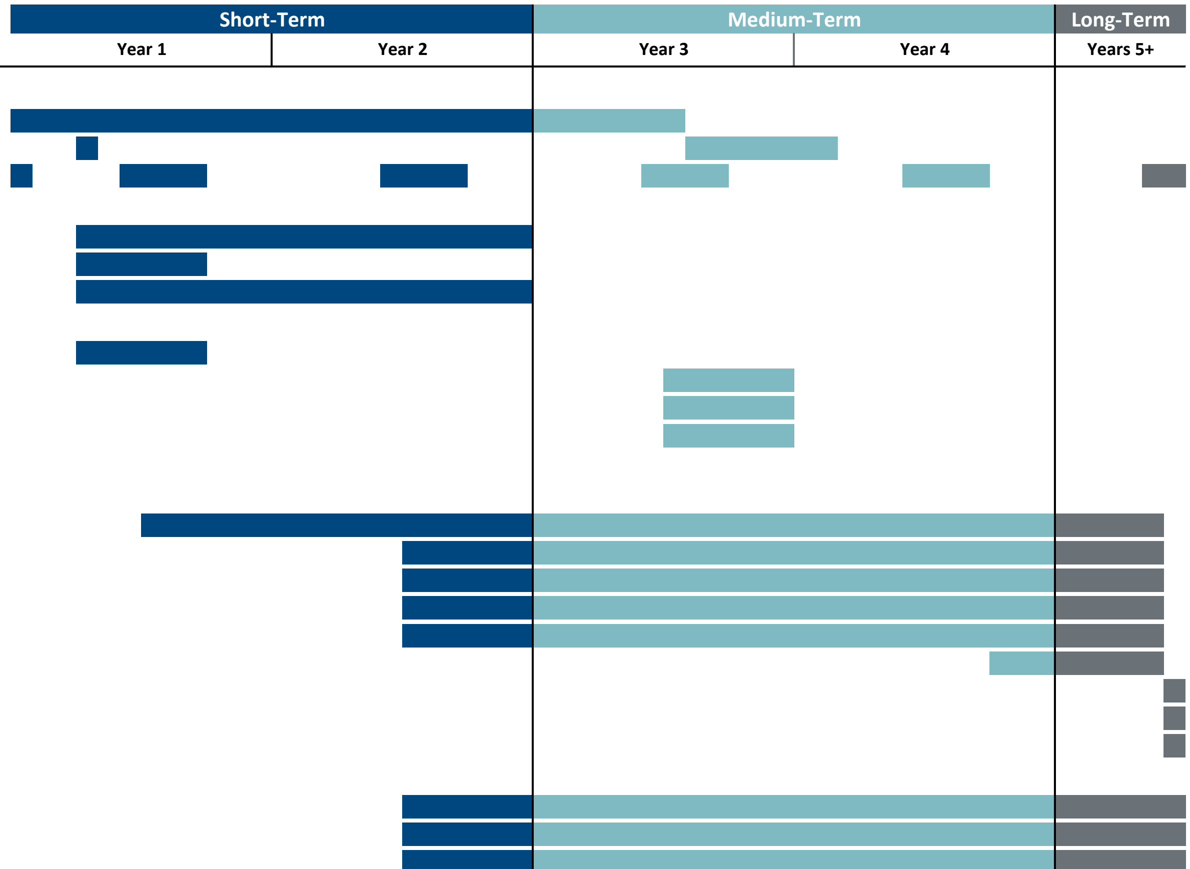
Panel E: Proposed Sequencing from Stakeholder 5

Issues to Address	Months
Lay the Foundations	
Carry out load research	36
Review cost of service study and determine need for new one	7
Conduct cost of service study (decide embedded vs. marginal)	10
Establish Class Allocation	
Consider customer classification based on SIC/nature of load	12
Consider classification of charitable organizations	12
Consider appropriateness of Small Industrial and GS tariffs	12
Resolve Equity Issues	
Review street lighting rates	0
Address cross-subsidization of heating customers	9
Consider concessions for vulnerable customers	9
Address GS I and Residential rate class inequities	9
Identify Rate Design Options	
Available without AMI	
Analyze the impact of new rates on customer bills	7
Consider introducing seasonal rates	5
Consider introducing opt-in TOU rates	5
Consider introducing opt-in fully hedged bills	5
Consider opt-in, opt-out, or mandatory deployment	5
Design pilots with new rate designs	5
Implement rate design pilots	5
Model rate switching behavior of customers	6
Plan and implement transition to new rates	9
Available with AMI	
Consider introducing default TOU rates	8
Consider introducing dynamic pricing rates	6
Consider introducing residential demand charge	8



Panel F: Proposed Sequencing from Stakeholder 6

Issues to Address	Months
Lay the Foundations	
Carry out load research	31
Review cost of service study and determine need for new one	8
Conduct cost of service study (decide embedded vs. marginal)	19
Establish Class Allocation	
Consider customer classification based on SIC/nature of load	21
Consider classification of charitable organizations	6
Consider appropriateness of Small Industrial and GS tariffs	21
Resolve Equity Issues	
Review street lighting rates	6
Address cross-subsidization of heating customers	6
Consider concessions for vulnerable customers	6
Address GS I and Residential rate class inequities	6
Identify Rate Design Options	
Available without AMI	
Analyze the impact of new rates on customer bills	47
Consider introducing seasonal rates	35
Consider introducing opt-in TOU rates	35
Consider introducing opt-in fully hedged bills	35
Consider opt-in, opt-out, or mandatory deployment	35
Design pilots with new rate designs	8
Implement rate design pilots	1
Model rate switching behavior of customers	1
Plan and implement transition to new rates	1
Available with AMI	
Consider introducing default TOU rates	36
Consider introducing dynamic pricing rates	36
Consider introducing residential demand charge	36



Notes: Stakeholder noted that the introduction of rate design options (*i.e.*, seasonal rates, TOU rates, hedged bills, dynamic pricing rates, and residential demand charges) should first be considered for business customers in the short-term before expanding to residential customers at the start of Year 4.

As shown in each Figure 13 panel and in Figure 14, which combines them into a single "heat map," there is considerable diversity in stakeholder views. Beyond just the sequencing of issues, there was disagreement as to when the whole process, or "Year 1," needs to begin, and disagreement on how many parties need to be involved with each issue.

However, there were areas of agreement. For instance, as shown in Figure 15, all stakeholders agreed that carrying out load research was a short-term priority and thus should come first. They also all prioritized establishing cost allocation in the short-term, and generally agreed that an overarching goal should be to analyze and remove cross-subsidies between customers (*i.e.*, restoring equity in rate design). To address this goal, it would be necessary to review the cost structure of generating and delivering electricity in order to bring rate design into conformity with costs.

Prior to making rate design enhancements, there was strong support for completing a marginal cost study for pricing purposes, with the understanding that marginal and embedded cost of service studies might produce two different sets of outputs and serve two purposes. This position reflects the belief that an embedded cost of service study provides a benchmark as a measure of equity but does not capture the attribute of cost reflectivity for a seasonal type of utility. Conducting a complete marginal cost study for the first time would be a more intensive process than simply refreshing an embedded cost study, but the process could begin earlier, while load data is still being collected. Some parties argued that a significant amount of data required for the marginal cost of service study has been collected by NB Power for the DSM Integrated Resource Plan, Evaluation, Measurement and Verification efforts and similar endeavors. For the most part, stakeholders placed the start of rate design issues further out, suggesting that focus should shift to rate design reform after reviewing cost classification and allocation.

Stakeholders generally dedicated the medium-term to considering rate design options, although a few indicated that certain options like seasonal rates could be resolved earlier on. Reviewing these optional or non-AMI rates and pilot results could then be used to inform the possible development of more innovative or wide-spread rate design reform, particularly with respect to residential customers. For instance, stakeholders tended to view dynamic pricing options as longer-term considerations for NB Power and the Board to consider when the necessary AMI infrastructure is in place.[17] Several stakeholders noted that these rates would likely come after NB Power has deployed seasonal and/or TOU rates, and customers are familiar with the notion of time-variation in rates.

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[17] The Board is expected to render a decision on NB Power's application for AMI by early 2020. If approved, NB Power projects that wide-scale roll-out should be completed in fiscal year 2023/2024.

Figure 14: Stakeholders' Proposed Sequencing of Issues

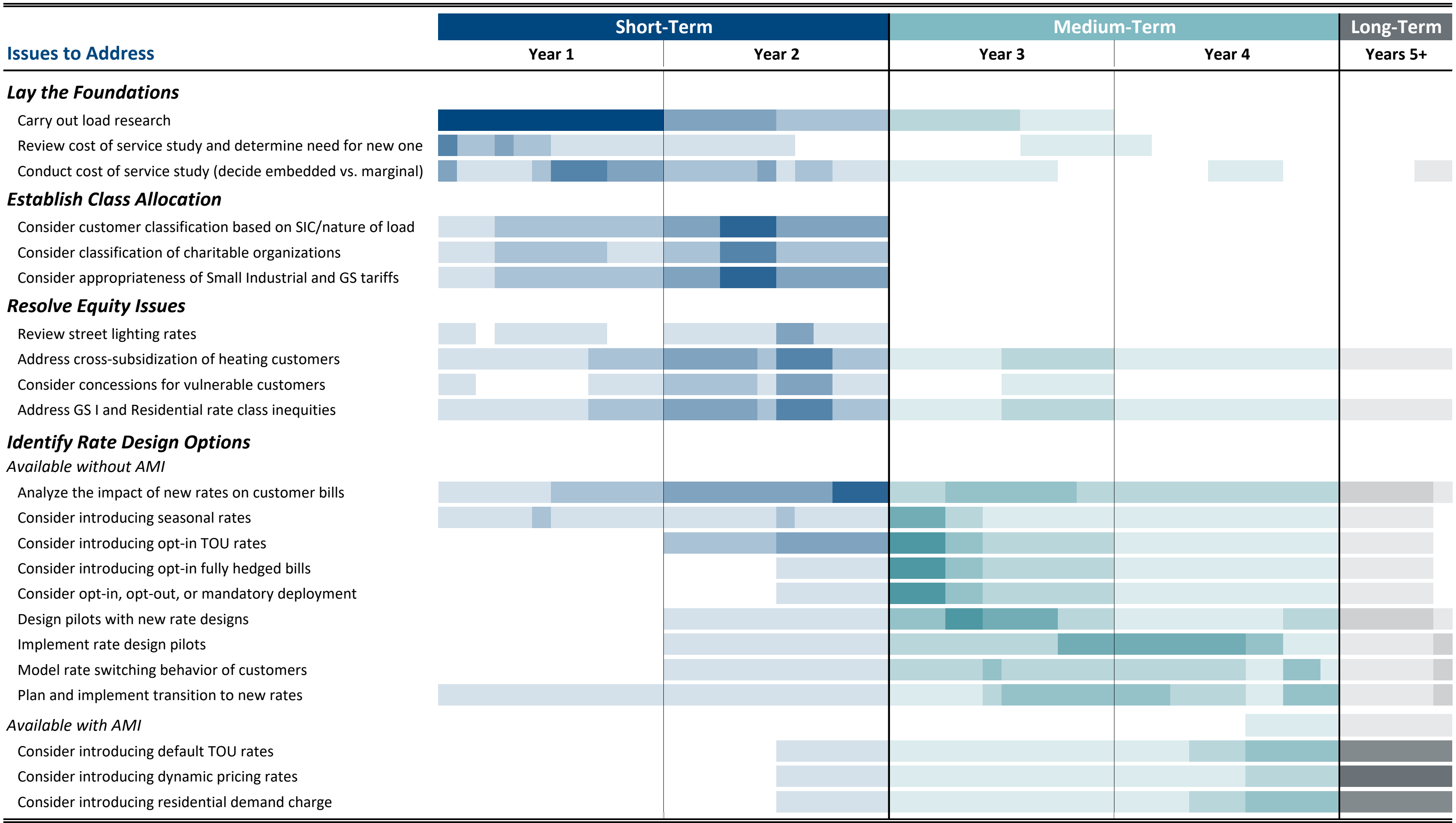
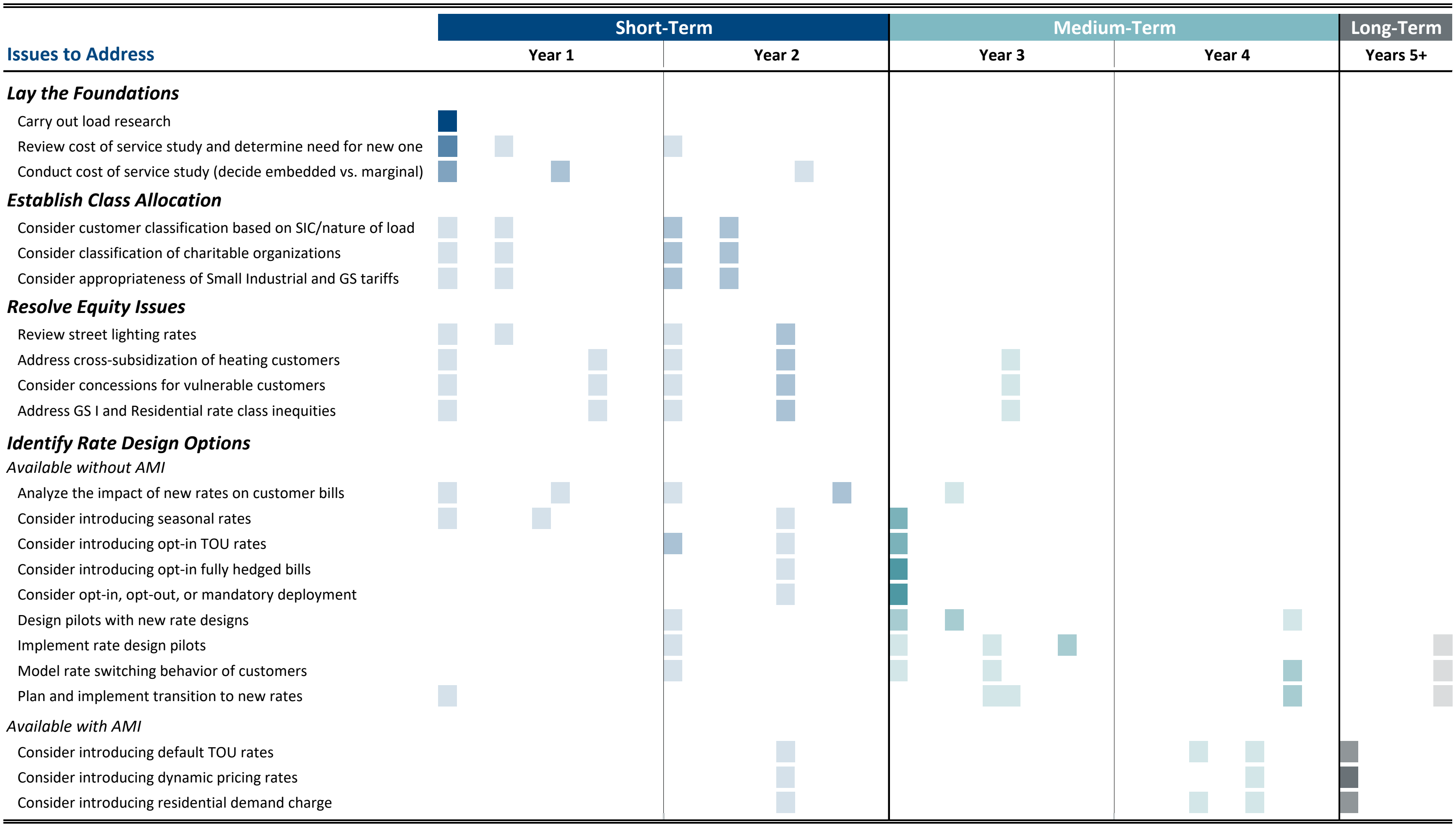


Figure 15: Stakeholders' Proposed Starting Month in which to Address Each Issue



A. Laying the Foundation

1. Carry out load research

Load research programs—which collect statistical samples of interval customer data to analyze a customer class's load shape—are a prerequisite for cost allocation and rate design. The presence of AMI can enhance these programs by improving class allocation and informing the implementation of dynamic pricing rates, but it is by no means mandatory and its absence need not hold up rate design reform.

In Matter 430, the Board agreed that NB Power's existing load data for the distribution classes needs to be refreshed, and requested that NB Power submit a proposal for a reinvigorated load research program.[18] Subject to renewal, results of NB Power's refreshed load research would likely be expected as early as by the end of fiscal year 2020/21.

2. Review and conduct cost of service study

As an important step in the rate-making process, a utility must determine its revenue requirement and overall costs incurred in providing service. The utility then functionalizes costs into production, transmission, distribution, and general categories, before further separating the functionalized costs by their demand, energy, or customer causality. The functionalized and classified revenue requirements are allocated to the different customer classes based on the load research's analysis of system and customer class demand characteristics. Only then can the utility finally design cost-based rates to recover the required revenue from each class.

The process of cost functionalization, classification, and allocation can take the form of either an embedded cost of service study, which relies on historical costs, or a marginal cost of service study, which relies on marginal or incremental costs. Stakeholders recognized that marginal costs are particularly useful in allocating generation costs and guiding certain retail prices where the overall price level must collect required revenues for the class. However, like most utilities, NB Power has historically relied exclusively on embedded cost of service studies, such as the current Class Cost Allocation Study (CCAS) model that resulted from an earlier stakeholder consultation process and subsequent Board approval.

Stakeholders all agreed that this form of embedded cost study remains appropriate for cost allocation purposes, and that the CCAS would need only be revisited to the extent required to enhance equity or accommodate new issues, or customer class definitions. Nonetheless, several stakeholders advocated that while continuing to use an embedded cost study for cost allocation, NB Power should rely on a marginal cost study for pricing purposes. To support this position, one

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18 *See* New Brunswick Energy and Utilities Board, Decision, Matter 430, July 16, 2019, p. 19. NB Power has since filed a load research program review prepared by DNV GL as Appendix E in Matter 452.

party at the first stakeholder session presented its recommendation for the preparation of an NB Power marginal cost study whose framework would be designed through a collaborative process. Moreover, as reflected in the preliminary scorecard results in Figure 4, there was largely consensus among the working group that cost reflectivity should be a priority,[19] which in terms of economically efficient rate design is typically best achieved through marginal cost pricing rather than embedded cost pricing.

Most stakeholders agreed that a marginal cost study would be required if cost-reflective rates are desired in NB Power's jurisdiction, consistent with Bonbright's key criterion of economic efficiency. Further, they maintained that if NB Power eventually invests in AMI infrastructure, new and innovative pricing would require a detailed knowledge of NB Power's marginal cost structure. However, at least one stakeholder raised concerns about using scarce resources for a general marginal cost study. That stakeholder cautioned that developing marginal costs can potentially be time-consuming and costly, and may give rise to issues of methodology. It was noted that instead of a general marginal cost study, NB Power has undertaken and will continue to undertake targeted marginal cost studies as a required basis for specific purposes.

B. Establishing Class Allocation

3. Consider customer classification based on nature of load

NB Power currently classifies customers according to the nature of their energy use, following rules outlined in its Rate Schedules and Policies Manual. The Residential class comprises customers who use electricity for living purposes, or to serve farms and churches. The General Service and Industrial classes separate commercial customers according to their standard industrial classification (SIC) code. Industrial customers are those "who use electricity chiefly for manufacturing, assembly or processing of goods, or the extraction of raw materials", while General Service customers include all retail customers who do not fall into other customer classes.

An issue in Matter 357 is whether or not NB Power should continue classifying customers according to the nature or purpose of their energy usage rather than the size of that usage, which would likely be more cost-reflective. Stakeholders recognized that this issue overlaps with others laid out in this section, most notably issue 5 concerning the appropriateness of separate Small Industrial and General Service tariffs.

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[19] Note that the voting took place without the benefit of a consensus definition of the cost reflectivity objective. At least one stakeholder voiced that support for cost reflectivity does not guarantee support for marginal cost pricing.

4. Classification of charitable organizations

NB Power currently serves all religious and charitable organizations that took service after August 29, 1979 under the General Service tariff, while such organizations taking service on a residential rate prior to August 29, 1979 continue to be served under the Residential tariff.[20] Given that General Service rates tend to be higher, this creates an inequity between the two different groups. Moreover, a grandfathered charitable organization that requires new service, reconnection, or upgrade will be moved to the General Service tariff, likely resulting in higher monthly bills and potential rate shock.

There is consensus that the inequity between grandfathered and non-grandfathered charitable organizations should be addressed, but a pending issue remains when and how to do so. NB Power may eliminate grandfathering and shift all of such organizations to the General Service class, or create a separate charitable tariff to intentionally subsidize such customers.

Some stakeholders indicated that this issue should consider the classification of all other non-residential customers currently eligible to take service on the Residential tariff, particularly farms and churches.[21]

5. Consider appropriateness of separate Small Industrial and GS tariffs

Given that customers are currently assigned to Small Industrial and General Service rate classes according to their SIC code rather than on their load characteristics, the Board must consider whether the two classes are different enough in cost to serve to justify separate customer classes.[22]

Moreover, even if separate rate classes are justified, a pending issue is the appropriateness of each class's tariff approach. NB Power currently serves small Industrial customers on a "Wright" tariff, which combines a demand charge of $7.14/kW with a two-tiered energy charge.[23] The energy charge follows a declining block rate structure, under which the first block charges 13.84¢/kWh for the first 100 kWh per kW, and the second 6.54¢/kWh for all additional consumption. However,

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20 NB Power, "RSP N-2: Rate Schedules and Policies Manual," accessed at https://www.nbpower.com/en/about-us/divisions/customer-service/policies/rspn2/.

21 Farms and churches often have similar energy consumption to residential customers, and historically churches have typically produced little load in peak hours. However, that is not always the case, and some farms and churches place significantly more demand on the system and require larger meters than residential customers.

22 As mentioned earlier, at least one stakeholder noted that this category could be combined with issue 3 or otherwise broadened to encompass all issues of customer class eligibility and tariff design, including the phase-out of the GS II tariff and the potential for alternative small/medium non-residential rate eligibility criteria.

23 The Small Industrial Service rate applies to Industrial customers with loads up to 750 kW.

General Service customers, who are more likely to sustain a higher load factor throughout the month, pay a three-part rate with a fixed charge, an energy charge, and a demand charge.

One possibility is that the Wright tariff is unnecessary and should be phased out for a tariff that is simpler and more understandable to customers. Eliminating the Wright tariff would likely result in adverse bill impacts for customers with low load factors, but would allow for a simpler rate design in case a seasonal or TOU component were to be introduced in the future.

C. Resolving Equity Issues

6. Review street lighting rates

NB Power currently treats street lights—together with water heaters and unmetered services—as market-based rate classes whose revenues exceed their costs. The Board recently ordered in Matter 430 that these excess revenues be allocated proportionally to all other rate classes.[24] One stakeholder advocated as its top priority that the revenue-to-cost ratio for street lighting be brought closer to what is considered a range of reasonableness for sales of electricity for NB Power's customer classes.

As initially presented, this issue considers whether street lights are subject to the revenue-to-cost ratio bandwidth, given their market-based categorization, and further whether this market-based treatment is actually appropriate. However, some stakeholders discussed extending the issue and seeking formal confirmation from the Board on appropriate rate setting methods for all competitive products and services.

7. Address cross-subsidization of heating customers

As discussed earlier in his report, one of stakeholders' most commonly cited issue was the cross-subsidization between customers with and without electric heating. Residential customers with electric winter space heating have different load shapes than those with natural gas heating, in that space heating demand is generally concentrated in peak periods when generation costs are highest. Under NB Power's current two-part tariff for residential customers, the higher cost of heating usage is likely being subsidized by customers without electric heating.

One option discussed to address this cost-shifting is the creation of a separate customer class for customers with electric heat. However, stakeholders did not consider this a viable option for NB Power's jurisdiction, noting the difficulty in defining and administering an electric heat customer class given the various combinations of heating options (*e.g.*, many homes have partial electric heating, mixed with oil, gas, wood, passive solar, *etc.*) and the lack of utility and regulatory visibility of how customers heat their homes. Also, adopting a separate rate class based on how a

24 New Brunswick Energy and Utilities Board, Decision, Matter 430, July 16, 2019, p. 17.

customer uses NB Power's service could set a precedent, leading to a myriad of requests for new customer classes. As a result, stakeholders instead favored addressing this issue through rate design, with the implementation of seasonal rates or, pending AMI approval, with the implementation of a residential time-varying rate or demand charge.

8. Consider concessions for vulnerable customers

Rather than address low-income issues through specific tariffs, utilities can offer vulnerable customers protections outside of rate design. For example, NB Power administers a Low-Income Energy Savings Program (LIESP), which provides low-income customers with free energy efficiency retrofits funded by the government of New Brunswick.[25] Multiple stakeholders voiced their view that protections for low-income and other vulnerable customers should come from government services, rather than through utility subsidies.

Many utilities offer medical assistance programs, under which customers who rely on life-support equipment or have qualifying medical conditions pay lower electricity rates.[26]

9. Address GS I and Residential rate class inequities

As of fiscal year 2019, the Residential class had a revenue-to-cost ratio below 0.95, compared to a revenue-to-cost ratio of over 1.18 for the GS I class, indicating some misalignment between prices and cost causation.[27] To improve inter-class price equity, the Board has generally indicated a desire to gradually move the Residential and GS I rate classes within the range of reasonableness of 0.95 to 1.05.

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25 "Low Income Energy Savings Program," New Brunswick Energy Efficiency Programs, accessed at https://www.saveenergynb.ca/en/save-energy/residential/low-income-energy-savings-program/.

26 For example, Xcel Energy's Colorado Medical Exemption Program and Fort Collins' Medical Assistance Program provide discounted electric medical rates to eligible customers to shield them from peak seasonal and Time-of-Day rates, respectively. Meanwhile, three California IOUs offer a Medical Baseline Allowance Program, under which eligible customers receive an additional allotment of energy at their tariff's lowest available price tier.

27 In Matter 430, there was some modest disagreement among the parties regarding cost allocation results. Nevertheless, parties agree that there is a wide spread between Residential and GS-I revenue-cost ratios.

D. Identifying Rate Design Options

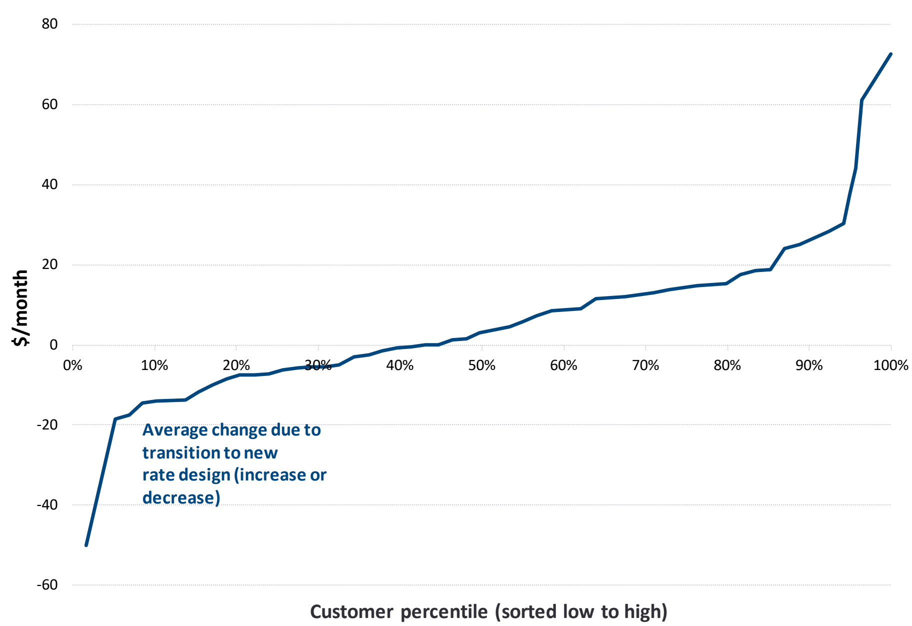
10. Analyze the impact of new rates on customer bills

In general, a change in rate design does not change the revenue being collected from the class. In industry parlance, it is revenue-neutral. However, most changes in rate design will raise bills for some customers and lower them for other customers, even if customer load shapes stay unchanged. For example, a move to seasonal rates will raise bills for customers who use more energy in peak season than the average customer and lower bills for customers who use less energy in the peak season. Similarly, a move from flat rates to time-of-use rates will raise bills for customers who use more energy in the peak period than the average customer and it will lower bills for customers who use less energy in the peak period. Of course, in the aggregate customer bills will not change.

Even then, it is a useful idea to conduct a billing distribution analysis before rolling out new rates. This requires having usage data on a representative sample of customers and computing the bills for each customer on the new rate design and comparing it to the current rate design. The results should be plotted out to see the magnitudes of the bill changes. If some customers will see significant bill changes, then the rate design may be modified or rolled out gradually.

An example distribution of billing impacts is show below in Figure 16. This chart is purely illustrative, with no connection to NB Power's specific rate offerings or customers. Actual bill impact distributions will vary by rate and utility. Some will be steeper and some will be gentler, depending on the existing distribution of customer load shapes and on the specifics of the new rate design being tested.

Figure 16: Example Bill Impact Distribution under Revenue-Neutral Modern Rate



At least one stakeholder expressed a concern that even if the new rate is revenue-neutral, as pictured in Figure 16, customers who see the largest bill increases (*i.e.*, the customers at the right end of the figure) might be low-income or elderly customers. This is a common concern, centered on the notion that such customers often have more difficulty altering their routines and responding to new rates. However, in many cases vulnerable customers may actually have higher load factors and see lower bill impacts.[28] These conflicting conceptions highlight the need to carry out such a billing distribution analysis, so that a utility may evaluate these worries, understand which customers will be most impacted by potential rate offerings, and, as discussed further later in this report, consider offering bill protections or remedies.

All stakeholders agreed that NB Power should conduct a billing analysis with any rate design or customer eligibility change. As a result, this issue can be viewed as a continuous extension of other rate design issues.

11. Consider introducing seasonal rates

Throughout the workshop, seasonal rates emerged as the top contender, as reflected in the scorecard results from Figure 5 and Figure 8. Stakeholders noted that the appeal of seasonal rates lay in part in their familiarity and feasibility. Although they may not be as cost-reflective as other TOU or dynamic pricing rates, which some stakeholders favored, default seasonal rates can help address intra-class subsidies without needing to wait for the implementation of AMI. In some way, they can be perceived as a step in the direction of TOU rates, whose impact would likely be more muted if they were offered only on an opt-in basis. Given their potential to more immediately improve equity, seasonal rates have by now been at the center of rate design discussions in New Brunswick for at least the past year and a half, and are a well-known issue to the entire working group.

That said, support for seasonal rates was not unanimous, even among stakeholders seeking more cost-reflective rates. At least one stakeholder suggested that given residential customer emphasis on low cost of power, priority should be given to other rate designs that will lead to changes in customer behavior and reductions in utility costs. According to that stakeholder, seasonal rates are not expected to result in material changes in customer consumption behavior. While customers with electric baseboard heat may be able to make some modifications to their total winter consumption and shift some of their consumption away from peak periods, most would have no easy means to switch fuels and cannot shift consumption from winter to summer. Also, consideration must be given to the future of home heating technology and fuels in light of the need to reduce GHGs.

Some participants were of the opinion that seasonal rates should be considered only within the context of a broader rate design strategy wherein TOU rates or other load shifting programs are also considered. In general it is important that the sequencing and transitions give due

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28 *See* Lisa Wood and Ahmad Faruqui, "Dynamic Pricing and Low-Income Customers," *Public Utilities Fortnightly* (November 2010):60-64.

consideration to the goals for the end state. Given that a decision on AMI is anticipated early in 2020, at least one stakeholder wondered whether the seasonality and time of use topics should be addressed concurrently, optimizing the efforts, and mitigating customer confusion and frustration. Although seasonal rates can be offered in conjunction with more complex rate designs like TOU, it was suggested that implementing seasonality first may make it difficult to later implement designs like TOU that could potentially provide more value to NB Power's customers. Other stakeholders supported addressing seasonality in the near-term, and cautioned against delaying this process and inhibiting rate design reform altogether.

12. Consider introducing opt-in TOU rates

Although default time-of-day TOU rates do require AMI infrastructure, NB Power and the Board could consider the implementation of opt-in TOU rates for customers who install interval meters. This decision can be made concurrently with the decision to offer seasonal rates. If seasonal rates are implemented first, TOU rates can be offered later after customers are accustomed to time-varying rates.

Some stakeholders questioned the amount of customer demand for optional TOU rates, and stressed the need for bill impact studies to give customers more context in their selection decision.

13. Consider introducing opt-in fully-hedged bills

In determining for which types of rates to offer and to conduct pilot studies, the Board and NB Power can consider offering fully-hedged bills that customers pay in equal monthly installments. These fixed monthly bills are available without AMI, but given the built-in risk adder are primarily targeted to risk-averse customers and are nearly exclusively offered on an opt-in basis. There was generally consensus among the working group that fixed monthly bills were not a priority for the province at this time.

14. Design and implement rate design pilots

If NB Power and the Board decide to implement modern rates like time-varying or dynamic pricing tariffs, there was generally consensus that they should first test them through pilot studies. Reviewing other pricing pilots offers valuable insight into best practices and lessons learned, and can help approximate customer response to preferred new rates. However, a utility must conduct its own pilot study to empirically assess how its own customers will respond given their specific demographics and loads. This is particularly relevant for NB Power, given that throughout the workshops, stakeholders repeatedly emphasized the unique generation mix and load characteristics that differentiate New Brunswick from other jurisdictions.

For instance, nearly two-thirds of NB Power's residential customers have electric winter space heating, which distinguishes their load shapes from those of non-electric heating customers. More specifically, New Brunswick's heating loads are predominantly baseboard heating, which cannot be automated the way AC units are through many direct load control programs. As a result, a common concern among stakeholders was that under time-varying rates, the prominence of electric heating could potentially mute customers' ability to respond to higher prices.

To minimize costs and timelines, pilots could potentially take advantage of existing pricing programs and infrastructure. For example, NB Power is planning to deploy smart meters for 500 homes in Shediac as part of its first Smart Energy Community Project.[29] Even more immediately, pilots could be implemented in other communities that have interval meters, like Saint John and Perth-Andover, which are respectively served by Saint John Energy and the Perth-Andover Electric Light Commission.

15. Model rate switching behavior of consumers

When customers are offered rate design choices along with the appropriate education and information about each of the choices, they are likely to pick the rate that best suits their energy lifestyle.

For example, some customers might want bill stability and may be unwilling to change their usage patterns, others might want the lowest bills and would be happy to change their usage patterns, while some others might want to buy power coming from renewable energy sources and are willing to pay more for it.

Depending on how customers make their rate choices, the utility may end up with a revenue shortfall or a revenue increase. Several stakeholders stressed the importance of NB Power being able to recover its full revenue requirement, in light of its precarious financial condition. Thus, it is important to model customer rate switching behavior and assess the likely impact on utility revenue. This is most often done with a technique known as discrete choice analysis.

16. Plan and implement transition to new rates

a. Opt-in, opt-out, or mandatory deployment

In deploying new rates, a utility may either make them mandatory, or offer them on an optional basis as either opt-in or opt-out. Opt-out rates are essentially "default" rates, under which all new and likely existing customers will automatically take service unless they specifically request a different tariff. The deployment of opt-out TOU or dynamic pricing rates would be contingent on the widespread deployment of AMI.

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29 NB Power, "Shediac home to New Brunswick's first Smart Energy Community Project," June 12, 2019, accessed at https://www.nbpower.com/en/about-us/news-media-centre/news/2019/shediac-home-to-new-brunswick-s-first-smart-energy-community-project/.

Typically, when a modern rate is deployed on a default basis, a significant majority of customers will remain on the new rate rather than actively choose to opt out. As a result, opt-out rates have much higher adoption rates than opt-in rates, but customers on these rates tend to be less familiar with their assigned tariff and less likely to respond to price signals. On the other hand, customers who opt-in to a program are more likely to have researched the program, and are therefore more likely to shift load to reduce their bill. Given that they have voluntarily selected their tariff, there is less risk of customer service concerns.

Stakeholders generally agreed that to achieve their desired objectives and get the largest number of customers on modern rate designs, new rates should be offered on an opt-out or mandatory basis. However, some stakeholders acknowledged the importance of gradualism and of avoiding rate shocks in transitioning customers to more modern rates.

To this end, new rates can be offered on an opt-in basis first, and only later transitioned to a default or mandatory basis, so as avoid surprising customers with a sudden change. Similarly, opt-out rates can be rolled out on a gradual basis, for instance by gradually increasing a seasonal price differential or a new demand charge's share of the bill, so as to give customers time to learn how the modern rates work and plan accordingly. Alternatively, new rates can be offered on either an opt-out or mandatory basis only to new customers, which reduces rate shock and any inertia to move from a prior tariff. This can be achieved by closing the current tariff and grandfathering customers for a period of time until they either change service or are gradually adjusted over, as NB Power did when it closed the General Service II (GS II) rate class to new customers over a decade ago.[30]

b. Protections for Adverse Bill Impacts

Under NB Power's current rates, certain groups of customers have benefited from years of cost-shifting. For instance, within the Residential class served by the same two-part tariff, low load factor customers have been subsidized by high load factor customers, and electric heating customers by non-heating customers. As a result, implementing new rates to reduce these subsidies should decrease bills for customers who were overpaying and increase bills for those who were underpaying. The latter group is sometimes termed "instant losers", in that their bills will automatically go up even if their usage stays constant. There is often concern about vocal opposition from this group, but it is worth noting that their bill increases are simply redressing existing inequities. Concurrently, while some stakeholders voiced concern that customers who benefit from new rates without altering their behavior may be considered free-riders, they can instead be considered "instant winners" who were overpaying under the old rate. The impacts of these transitional effects should be understood and potentially tempered by consideration for the notion of historical continuity.

Intelligently-designed modern rates leverage economic efficiencies to ensure that the overall rate savings in the long run will exceed any bill increases in the short run that some customers might

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30 NB Power is continuing to phase out the GS II class, through gradual tariff harmonization for the GS I and GS II classes, customer attrition, and customer conversion.

experience. As explained earlier in this report, if the modern rate is designed to be revenue-neutral, it will initially produce savings for some customers, which in the aggregate will be equal to the aggregate bill increases experienced by other customers. However, as a result of offering cost-reflective price signals and creating opportunities for load shifting, customer behavior will change over time to reduce total system costs. Those net savings will accrue to ratepayers and put downward pressure on rates in the future.

To mitigate initial concerns of significant adverse bill impacts for certain customers, the utility can institute certain remedies.[31] For example, it may provide these customers with bill protections in at least the first year, before gradually phasing them out over the next few years. Alternatively, it may offer financial assistance for a limited period of time, or provide enabling technologies such as smart thermostats to help customers respond to new rates.

17. Consider introducing default TOU rates

Research in behavioral economics pioneered by Nobel laureate Richard Thaler of the University of Chicago and his colleagues has shown that customers are often busy with day-to-day activities in life and are often unable to make the choices that would be best for them. Thus, it is important to provide the most appropriate rate design as the default rate. From an economic perspective, the best rate design would be the one that best reflects the cost of supplying electricity to the customer, as noted in earlier sections of this report. It could be a three-part rate including a demand charge or a TOU rate. As mentioned in Section IV.A, Fort Collins in Colorado, a municipal utility, moved all its customers to a mandatory TOU rate in October 2018, and utilities in Michigan and California are moving all their residential customers to TOU rates in 2020. About a decade ago, the province of Ontario made TOU rates the default rate for its four million residential and small commercial and industrial customers. Econometric analysis shows that customers in the aggregate reduced their peak demand.[32]

Research has shown that economic efficiency is generally improved by moving customers from traditional two-part rates to default TOU rates. Even though the impact per customer (*e.g.*, the reduction in peak load) is lower with a default deployment than with an opt-in deployment, the aggregate impact is higher because a much larger percentage of customers would be engaged with default deployment.[33]

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[31] *See* Ahmad Faruqui, Léa Grausz, and Cecile Bourbonnais, "Transitioning to Modern Residential Rate Designs," *Public Utilities Fortnightly* (January 2019): 30–35 and Ahmad Faruqui and Mariko Geronimo Aydin, "Moving Forward with Tariff Reform," *Regulation* (Fall 2017): 42–48.

[32] Neil Lessem, Ahmad Faruqui, Sanem Sergici, and Dean Mountain, "Impact of Time-of-Use Rates in Ontario," *Public Utilities Fortnightly* (February 2017):56-87.

[33] Ahmad Faruqui, Ryan Hledik, and Neil Lessem, "Smart by Default," *Public Utilities Fortnightly* (August 2014):24-32.

18. Consider introducing dynamic pricing rates

With respect to economic efficiency, most stakeholders recognized that dynamic pricing rates are an advancement over TOU rates, particularly given the weather-sensitive nature of NB Power's load. There are certain days in each power system when demand and supply are extremely unbalanced. Across a wide range of utilities it has been the case that the top 100 hours of the year can account for as much as ten percent of annual peak demand. On such days, prices rise in wholesale markets, reserve margins are stretched, and there is a risk of blackouts. These days are hard to predict in advance and are dynamic in nature, and thus cannot be addressed effectively with TOU pricing.

One way to manage the extreme peak loads on such days is to raise the price of electricity to retail customers. There are several ways of doing it, which collectively are called dynamic pricing. Examples include Critical Peak Pricing, Peak Time Rebate, and Real Time Pricing. Although still considerably less widespread than TOU rates, all of these have been offered and tested empirically through experiments. They are being offered in California, Illinois, Maryland, and Oklahoma in the U.S. and have been tested in many other jurisdictions including Connecticut, Florida, Washington, DC, and Ontario.

19. Consider introducing residential rates with demand charges

Supplying and delivering electric service to consumers involves two things: generating the power and then transmitting and delivering it. When the consumer flips the switch, the consumer is really buying two products: energy and demand (sometimes called capacity). Fully cost-reflective rate designs thus involve both an energy charge and a demand charge (both of which may be TOU or dynamic), in addition to a monthly service charge. Such rates have long been offered to commercial and industrial customers, especially the larger ones for whom they have often been mandatory.

Demand charges are now being offered to residential customers in more than twenty states in the U.S. Overall, stakeholders expressed a preference for not considering demand charges until after the potential adoption of AMI, and they prioritized time-varying rates over demand charges. However, as shown in Figure 10, four out of seven respondents voted to consider a demand charge as a rate design priority if AMI were in place.

VI. Next Steps in the Stakeholder Engagement Process

The one thing that echoed through the three workshops was the diversity of opinion among stakeholders on rate design reform. At the same time, all stakeholders appreciated being involved in what they regarded as an important process for redesigning rates in the province. But there was divergence of opinion when it came to discussing and prioritizing specific rate design innovations.

However, regardless of the specific shape that any rate design reform takes, most participants voiced a desire to move the ball forward. While discussing the specific timelines for the Board's hearing process, there was a consensus that flexibility should be maintained, given all the other activities that stakeholders are involved in.

The stakeholders were informed early on that that once the workshops had been completed and this report written up and filed with the Board in both languages of the province, there would be a Brattle presentation on the issues aired during the workshop and summarized in the report. Stakeholders will have a chance to comment on the report and to share their views on rate design with the Board following Brattle's presentation.

Once the Board has reviewed the evidence presented through the report and stakeholder submissions, it would issue a decision detailing how NB Power should proceed with implementing the stakeholder recommendations.

The stakeholders have not detailed a specific, detailed path to reforming rates. Instead, they recognized that reform of rate design ought to remain flexible enough to respond to how customers accept and respond to the new rate designs. Thus, the recommendations and suggested sequencings in this report are not intended to be definitive or prescriptive, but to be suggestive.

It goes without saying that this report reflects only the views of the stakeholders who attended the workshops and chose to participate in the discussions and exercises. None of the results, particularly the quantitative ones, have been adjusted to compensate for any limitations that might exist in the composition of the stakeholders.

Moving forward, all stakeholders saw value in maintaining transparency and collaboration in the process through the establishment of working groups for selected topics. Defining their specific scope beyond the goal of consensus building would require further discussion. While some stakeholders noted that workshops can significantly reduce the amount of time spent in hearings, working groups would also be subject to scheduling and resource constraints. As a result, this collaborative process should likely be restricted to the most pressing and consequential issues, for instance the review of load research and cost of service studies, while others might get resolved directly by NB Power and the Board.

Ultimately, the Board has the prerogative to decide which of these issues to pursue, and then when and how to pursue them. It always has the option of retaining the status quo.

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Appendix:

NBEUB Letter to All Parties in Matter 357

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May 14, 2019

Via Email

To All Parties:

Re: Matter 357 - NB Power Rate Design

This letter is further to the procedural conference that was held on October 12, 2018 in connection with the above-noted matter.

The Board has determined as follows:

a) Matter 357 will continue to exist as an active Matter.

b) The existing evidentiary record for Matter 357 will continue to be the evidence in this Matter.

c) The Board has determined that an independent facilitator is required to assist in scoping the issues for determination. The Board has retained The Brattle Group to assist the stakeholders with the following items:

   i) Identifying the issues for determination in Matter 357, based on the evidentiary record and based on comments from stakeholders; and

   ii) Determining what issues should and can be resolved in the immediate future and those issues that need to be resolved on a medium and long-term basis.

d) Rate design is an important issue. As an overarching principle, the goals of reviewing the current rate design include but are not limited to:

   i) Reducing any inequity that may exist or may be caused by the current rate structure (on a short-term, medium-term and long-term basis);

   ii) Establishing a rate design methodology that is easily adaptable to future changes (including changing technologies and the business environment); and

   iii) Establishing a rate design methodology that is clear, managed and predictable, allowing customers, utilities, the government and stakeholders to make the necessary investments and appropriate behavior changes.

e) NB Power will not be required to file any new evidence or documentation prior to the stakeholder sessions beginning. The Board finds that the current evidentiary record provides a starting point for these conversations.

<u>The Brattle Group</u>:

In retaining The Brattle Group, the objective is to create a forum for meaningful discussion. At the same time, the process must be efficient, purposeful and cost effective. The Brattle Group has been retained to provide a report to the Board as soon as possible with respect to the following issues:

a) The recommended scope of the hearing for Matter 357;

b) The issues that need to be addressed immediately, in the medium term and in the long term;

c) What, if any, additional studies may be required;

d) A suggested timeline for when such studies (if any) can be completed;

e) A suggested timeline for the formal hearing for Matter 357; and

f) A suggested timeline for when medium and long-term issues should be considered by the Board.

g) The report should advise where there is consensus or where there is disagreement. With respect to those issues where there is no consensus, a summary of the stakeholders' positions will also be included.

<u>Sessions with Stakeholders</u>:

a) It is anticipated that approximately three sessions of the stakeholders will be required. The first session will be held on June 26, 2019 at the Wu Centre in Fredericton, beginning at 9:30 a.m. The second and third sessions are slated for early August and late September.

b) A conference call will be held on June 11, 2019, in advance of the first stakeholder session. This call will provide Brattle with an opportunity to meet participants in advance, outline the process and answer any process questions that stakeholders may have. Details of the call will be circulated in the coming days.

c) The Brattle Group will be directed to make every effort to accommodate the various schedules of the stakeholders however, accommodation may not always be possible.

d) During this stakeholder process, there may be issues that arise that require Board determination. If so, the stakeholders are to notify the Board and a hearing/meeting date will be scheduled as soon as possible so that the process is not delayed.

e) Following receipt of the report, the Board will provide further direction to the stakeholders.

The Board recognizes the unique nature of this filing and the unique nature of this process. Additional sessions or educational components may be required as we move forward. Rate design is important and the decisions arising from this Matter will likely have long term-impacts for all customers.

In addition, public consultation is an important part of any process of the Board. As a result, the Board will consider how additional public comments can be provided to the Board as the hearing proceeds. Stakeholders should discuss this issue as well.

The Board appreciates your cooperation as this Matter continues to unfold.

Yours truly,

Kathleen Mitchell

Kathleen Mitchell
Chief Clerk

NORTH AMERICA | EUROPE | ASIA-PACIFIC

THE Brattle GROUP