Review of Maritime Electric's Proposed Rate Changes

Prepared for Carr, Stevenson & MacKay

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1. INTRODUCTION

The Island Regulatory and Appeals Commission ("IRAC" or the "Commission") has repeatedly expressed its concerns with inequities in the rate structures offered by Maritime Electric Company, Limited ("Maritime Electric," "MECL," or "the Company"). These concerns are primarily related to the residential declining block rate structure and revenue-to-cost (RTC) ratios for certain classes that deviate significantly from 100 percent.

According to 2017 data provided by the Company, the residential class contributes less to revenues than it imposes in costs on the system, with a revenue-to-cost (RTC) ratio of approximately 92 percent.[1] This condition is exacerbated by the residential declining block rate, which assesses a lower rate for higher usage, and results in higher-use customers contributing much less in revenues than the costs imposed on the system.[2] At the same time, the General Service class has persistently exhibited a revenue-to-cost ratio well above 100 percent.[3]

To address these inequities, the Commission directed Maritime Electric to file a comprehensive proposal for a new rate structure addressing the declining block rate structure, the treatment of farm customers (who are currently included in the Residential class), correcting inequities in the RTC ratios. Further, the Commission stated its expectation that the Company's proposal would "consider new and innovative rate structures that may provide tangible benefits to its customers."[4]

On June 30, 2020, Maritime Electric filed its Electric Rate Design Study, prepared by its consultant Robert Boutilier, and on May 14, 2021, Maritime Electric filed its Application for Stage 1 Rate Design Changes. The Company's May 2021 Application includes preliminary residential class load study results that segment the residential class into seven customer cohorts based on type and quantity of usage.

[1] MECL, Application for an Order to Approve the Stage 1 Rate Design Changes, Table 3, May 14, 2021, p. 24.

[2] *Ibid.*

[3] *Id.,* Table 2, p. 22.

[4] IRAC Order UE20-06, paragraph 203.

Table 1. Characteristics of residential class customer cohorts

Residential Year-Round Rate Codes 110 & 130					
January 2020 Billing Cohorts	# Customers	Share of Total Customers	Share of Total Energy	Share of 2017 Allocated Costs	RTC Ratio
1. Usage 0 to 575 kWh	22,807	28.2%	7.2%	10.5%	102%
2. Usage 576 to 1,200 kWh	18,980	23.5%	12.6%	15.9%	95%
3. Usage 1,201 to 2,300 kWh	11,687	14.4%	11.8%	13.7%	95%
4. Usage 2,301 to 5,000 kWh	7,017	8.7%	11.6%	14.3%	82%
5. Domestic > 5,000 kWh	293	0.4%	0.9%	1.1%	71%
6. Farms > 5,000 kWh	418	0.5%	3.3%	3.1%	85%
7. Other > 5,000 kWh	45	0.1%	0.8%	1.0%	65%
Combined	61,247	75.7%	48.2%	59.5%	92%

Source: Calculated using data from MECL's Rate Design Application Appendix C, Preliminary Residential Class Load Study Results, Table 3, p. 7, and MECL's 2017 Cost Allocation Study.

As can be seen from the table, the lowest-usage customers in the residential class have the highest RTC ratio (at 102 percent) while customers in cohorts who consumed more than 5,000 kWh in January 2020 have RTC ratios ranging from 65 percent to 85 percent. These high-usage cohorts include larger farms as well as 45 customers in an "Other" category.

The Company's rate plan proposes to mitigate the RTC ratio variations by eliminating the declining block structure in which monthly usage above 2,000 kWh is priced lower than usage in the first block. MECL proposes to phase out the second block energy charge over four years in an effort to minimize rate shock,[5] as eliminating the lower-priced energy block will increase bills for high usage customers. In addition, the Company proposes to allow non-domestic customers who are currently in the residential class to take service on the small industrial tariff as a means to reduce bill increases.[6]

In the near-term, the Company also proposes to increase rates for the Large Industrial and Street Lighting classes and reduce the rates for the General Service class to bring the RTC ratios for these classes closer to 100 percent.[7] The Company's application did not propose that innovative rate structures (such as TOU rates) be implemented in the near-term, although it did note that such rates could be beneficial in the longer-term.

Following the filing of Maritime Electric's Application, Counsel to the Commission retained Synapse Energy Economics, Inc. (Synapse) to review and assess the reasonableness of Maritime Electric's proposal, as well as examine certain elements of Maritime Electric's cost allocation methodology. This report summarizes Synapse's findings and recommendations.

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[5] MECL, Application for an Order to Approve the Stage 1 Rate Design Changes, Table 3, May 14, 2021, p. 21.

[6] *Id.,* p. 30.

[7] *Id.,* p. 21.

2. RATEMAKING PRINCIPLES

Ratemaking is not formulaic – it often requires the careful balancing of multiple objectives that may be in tension with one another and requires the regulator to exercise judgement. The modification of Maritime Electric's rates is no different, as there are multiple tradeoffs associated with the various rate design and cost allocation options. In evaluating the merits of various options, it is helpful to refer to the criteria for a sound rate structure established by Professor James Bonbright in his seminal work, Principles of Public Utility Rates.[8] These criteria are:

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with minimum of unexpected changes seriously adverse to existing customers.
6. Fairness of the specific rates in the appointment of total costs of service among the different customers.
7. Avoidance of "undue discrimination" in rate relationships.
8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
    a. in the control of the total amounts of service supplied by the Company;
    b. in the control of the relative uses of alternative types of service.

These principles have been recognized for many years as the standard for rate design by commissions across North America. In many ways, Maritime Electric's rate plan appears to satisfy these criteria by apportioning costs more fairly among customers through improving revenue-to-cost ratios, while minimizing adverse consequences to customers by phasing in changes over time and allowing large customers to opt onto a different rate schedule. However, there are certain aspects of Maritime Electric's rates that could also be substantially improved in order to provide customers with more efficient price signals and enhance fairness within rate classes. In particular, the high residential service charge (also called a "customer charge") does not promote conservation of energy and is not rooted in a careful analysis of customer-related costs. Finally, Maritime Electric's time-invariant rates do not convey useful information to customers regarding the temporal variation of system costs, including capacity

[8] James Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961, page 291

costs. Without such price signals, peak demands on the system are likely to exceed efficient levels, resulting in higher costs for all customers.

3. DECLINING BLOCK RATES AND EQUITY

Maritime Electric's current residential rate schedule exhibits a declining block structure in which monthly usage above 2,000 kWh is priced approximately 21 percent lower than usage in the first block.[9] In some cases, declining block rates may be justified based on policy concerns (such as mitigating high bills for customers with electric heat or other electrified end uses),[10] or differences in cost causation. However, concerns are also frequently raised that declining block rates send distorted price signals that induce wasteful energy consumption, leading to new investments in generation, transmission, and distribution capacity that increase costs for all customers. Further, declining block rates raise equity concerns where they are not supported by differences in cost causation.

The Commission has repeatedly expressed reservations regarding Maritime Electric's residential declining block rate, and in Order UE16-04, noted that continuation of the declining block rate would require "compelling evidence of its equity to ratepayers."[11] In questioning the merits of the declining block rate structure, the Commission is in line with regulators and policymakers in numerous other jurisdictions who have cited concerns regarding the fairness of declining block rates and their impacts on conservation.[12] As a result, many jurisdictions have moved away from declining block rates, particularly for residential customers. Maritime Electric's Rate Design Study notes that, of the sampled utilities, Maritime Electric "has the only declining block residential rate other than the SaskPower farm rate."[13]

In the sections below, we analyze the cost reflectivity of Maritime Electric's declining block rate structure and the reasonableness of Maritime Electric's proposal to eliminate the second block.

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[9] MECL's residential rate currently has a first block price of $0.1479/kWh and a second block price of $0.1180/kWh, as shown in its Amended Appendix 1 Schedule of Proposed Rates, UE20944.

[10] As discussed in Section 6, however, more sophisticated time-differentiated rate designs that leverage AMI may provide superior alternatives.

[11] IRAC Order UE16-04R, paragraph 59.

[12] For example, in a recent order, the Maryland Public Service Commission noted that "the majority of states as well as PURPA (Public Utility Regulatory Policy Act) have expressly concluded that declining block rate structures do incentivize increased energy consumption." See MD PSC. Case No. 9651. Order 89799, p. 36.

[13] MECL Rate Design Study, June 20, 2020, at 25.

3.1. Assessing the Cost Reflectivity of Declining Block Rates

Load Factors and Revenue-to-Cost Ratios for Residential Customer Cohorts

A key criterion for determining whether a structure is equitable is the extent to which it is cost reflective. Cost reflectivity refers to the correspondence of revenues collected from customers to the costs that they impose on the system. This standard may be applied both at the individual customer and aggregate class levels.

To fairly allocate costs to the various customer classes, the utility conducts a cost allocation study. In this study, costs are classified according to whether they are primarily demand-related, energy-related, or customer-related (or some combination). Energy-related costs are allocated according to measures of energy usage, while demand-related costs are largely allocated based on class coincident peak (CP) demand or class non-coincident peak (NCP) demand.[14] These demand allocators are intended to reflect the extent to which the system must be sized to meet peak demand at the aggregate system level and at the local level. The coincident peak allocator is based on demand during the period when the entire system peaks,[15] while the non-coincident peak demand allocator is based on the peak demand for a specific customer class, regardless of whether it occurs at the same time as the system peak. Coincident peak allocators are frequently used for allocating generation and transmission costs, while NCP allocators are used for distribution system costs where the facilities are located closer to end-use customers and experience less diversity in demand.

Measures of CP and NCP demand can also be used to determine the relative cost of serving an individual customer or group of customers relative to their peers. In particular, the concept of "load factor" reflects the ratio of average energy consumption to peak demand over some period. For example, if a customer's maximum hourly demand is 10 kW and their average hourly consumption is 2.7 kW, then the customer's load factor would be 27 percent.

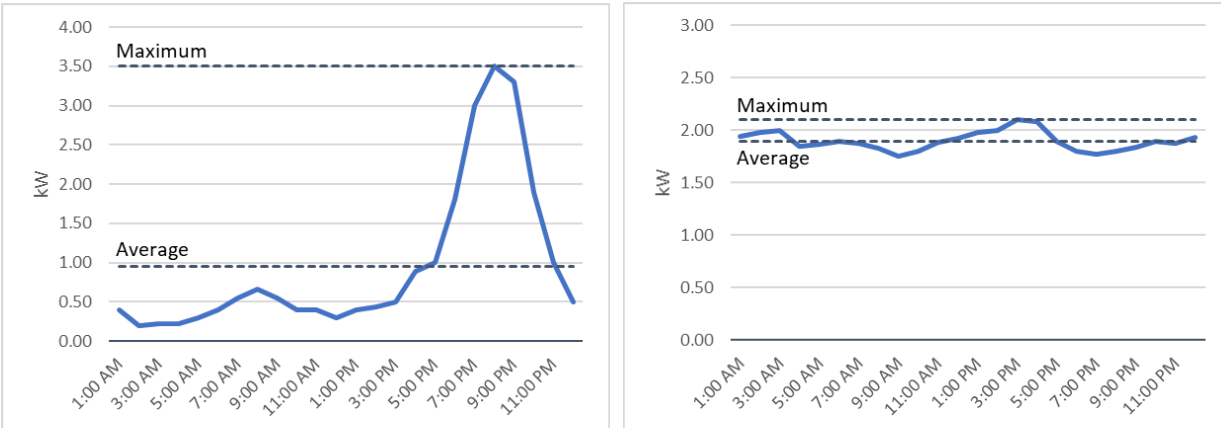
Higher load factors indicate lower average cost to serve, all else equal, because the system capacity is being utilized more efficiently. A 90 percent load factor would reflect usage that is very flat over the course of the year, with peak demand only slightly higher than average demand. In contrast, if the load factor is 27 percent, then approximately four times as much capacity must be constructed to serve peak load as is required to serve average load, even though much of the capacity will sit idle for much of the year.[16] These differences are illustrated in the following two hypothetical load curves.

[14] In some cases, a portion of distribution costs may also be allocated based on individual customer peak demands.

[15] According to MECL's 2020 cost allocation study, the annual system peak typically occurs in December when demand for lighting and heating is greatest. However, in 2020, the annual peak occurred during a winter storm in January. Chymko Consulting Ltd., 2020 Cost Allocation Study, July 21, 2021, p. 19.

[16] Note that load diversity – the extent to which individual customers' peaks occur at different times – can help mitigate the cost of serving low load factor customers.

Figure 1. Illustration of a hypothetical 27 percent load factor (left) and 90 percent load factor (right)



Tariffs that are primarily volumetric and non-time-varying (i.e., recovering most costs through a $/kWh charge rather than through a demand charge or a time-of-use rate) can lead to intra-class inequities among customers with differing load factors, because each customer pays the same volumetric rate, regardless of their actual load factor. A declining (or inclining) block rate structure can improve equity if there is a correlation between customer load factors and usage levels. That is, the declining block rate could be equitable if customers that benefit from a lower-priced second block (i.e., higher-usage customers) also tend to have better (higher) load factors.[17] However, the data provided by Maritime Electric does not support such a relationship. Instead, Table 2 shows that the load factor worsens (decreases) as usage increases. Likewise, the revenue-to-cost ratio also generally declines as usage increases. Large farms, however, are the exception with better load factors and RTC ratios than most of the other cohorts.

Table 2. Load factors of residential class usage cohorts

Residential Year-Round Rate Codes 110 & 130			
January Billing Cohorts	CP Load Factor (%)	NCP Load Factor (%)	RTC Ratio
1. Usage 0 to 575 kWh	63.1	39.7	102%
2. Usage 576 to 1,200 kWh	45.7	44.1	95%
3. Usage 1,201 to 2,300 kWh	47.0	45.3	95%
4. Usage 2,301 to 5,000 kWh	35.5	35.5	82%
5. Domestic > 5,000 kWh	30.8	30.8	71%
6. Farms > 5,000 kWh	62.2	45.3	85%
7. Other > 5,000 kWh	36.3	25.5	65%

Source: Synapse calculations based on Exhibit M-1, Response to Roger King IR-1, Attachment 1

[17] For rate structures that do not include demand charges, such as Maritime Electric's declining block rate, volumetric energy charges are purely cost reflective only i the ratio of customer coincident peak demand to customer total energy consumption is equal for all customers on the rate. In practice, customers are heterogeneous, and such a standard is unlikely to be met.

Although these results indicate that non-farm higher-usage customers use the system less efficiently and are therefore more costly to serve on a unit basis, the results should be interpreted cautiously because MECL lacks adequate demand data for several of the cohorts. Specifically:

- No customers in Cohort 5 ("Domestic > 5,000 kWh") have interval metering and only one of the 293 customers has a demand meter. Thus, the peak demands for Cohort 5 were estimated by scaling Cohort 4 peak demands for January 2020 to Cohort 5 energy sales for that month.[18]

- Although 10 customers in Cohort 7 ("Other > 5,000 kWh") have meters capable of measuring a customer's maximum demand, only one customer (the largest customer) has interval metering. Thus, the peak demands for Cohort 7 were estimated using interval data for the largest single customer in the cohort.[19]

Due to the dearth of interval data for these cohorts, we are not convinced that the CP or NCP estimates for Cohort 5 and Cohort 7 are sufficiently reliable for the purpose of drawing firm conclusions regarding RTC ratios and cost-reflective rate designs. Further, a large portion of the load in Cohort 7 is farm-related or commercial in nature, and thus appears to belong in the large farm category (Cohort 6) or the general service class.[20] Moving these customers into the farms cohort would likely worsen the RTC ratio for farms and potentially improve the RTC ratios for the remaining customers in Cohort 7. For example, if the largest customer in Cohort 7 were moved into the large farm cohort, the large farm CP load factor would worsen to 58 percent CP and the 42 percent NCP.[21]

Despite these concerns regarding the availability and accuracy of the data for higher-usage customers, the load research data for Cohort 1 through Cohort 4 appear to be sound. Focusing only on these cohorts, it is apparent that the higher usage customers (with usage between 2,300 kWh and 5,000 kWh) are contributing less than their share of revenues under the declining block rate structure. Thus, the current declining block structure appears to be causing an intra-class subsidy from lower-usage customers to higher-usage customers.

[18] In response to Synapse IR-3 (b), dated March 2, 2022, MECL explains that the "CP and NCP loads for Cohort 5 were estimated by using the corresponding Cohort 4 loads for January 2020, multiplied by the ratio of the Cohort 5 kWh sales for that month to the Cohort 4 kWh sales for that month." Although this preserves the same load factor for each cohort for January, the annual load factors for the two cohorts diverge due to differences in the proportion of load occurring in January.

[19] Response to Synapse IR-3 (c), dated March 2, 2022.

[20] Response to Synapse IR-1 (a), dated March 2, 2022 indicates that Cohort 7 includes three fish farms and nine agricultural-related customers.

[21] In response to Synapse IR-3 (c), dated March 2, 2022, MECL indicated that the largest customer in Cohort 7 comprised approximately 40% of the cohort load, which implies a CP demand of 1.32 MW, a NCP demand of 1.88 MW, and annual energy usage of 4.2 GWh.

Impact of Removing the Declining Block Rate Structure

Maritime Electric provided estimates of the impacts of eliminating the declining block rate, as well as a scenario in which high-usage non-domestic customers have the option of taking service on a different rate or of remaining on the residential tariff. Table 3 summarizes the results for three scenarios:

1. The current case, with the declining block rate in place;
2. A scenario in which the declining block rate is eliminated and all customers remain on the residential rate; and
3. A scenario in which the declining block rate is eliminated and non-domestic customers with January consumption exceeding 5,000 kWh are afforded the option of taking service on the small industrial rate.

Table 3. Projected impacts on RTC ratios from eliminating the declining block rate

Residential Year-Round Rate Codes 110 & 130			
January Billing Cohorts	1. Current RTC Ratio	2. RTC Ratio Without Declining Block	3. RTC Ratio Without Declining Block and With Optionality
Usage up to 2,300 kWh	96.9	97.3	97.3
Usage 2,301 to 5,000 kWh	81.9	85.2	85.2
Domestic > 5,000 kWh	70.7	78.8	78.8
Farms > 5,000 kWh	85.0	102.2	97.6
Other > 5,000 kWh	65.1	80.7	74.4
Overall	91.7	94.0	93.7

Source: MECL's Rate Design Application, May 14, 2021, Table 6 workpapers (response to Synapse IR 8a).

According to the Company's analysis, elimination of the declining block rate structure (moving from Step 1 to Step 2) is expected to increase the residential RTC ratio in the following ways:

- For moderate-use customers with consumption between 2,301 and 5,000 kWh per month, the RTC ratio increases by 3.3 percentage points, from 81.9 percent to 85.2 percent.[22]
- For customers with monthly usage exceeding 5,000 kWh, the RTC ratio increases by 8.1 percentage points for domestic customers (from 70.7 percent to 78.8 percent) and 16.5 percentage points for farms (from 85.0 percent to 102.2 percent). This larger impact is unsurprising, since these customers on the high end of the consumption spectrum

[22] MECL's Rate Design Application, May 14, 2021, Table 8, p. 35.

currently realize a discount through declining block rate on a greater share of their total monthly energy consumption.[23]

The elimination of the declining block rate structure improves the RTC ratio for all cohorts examined. However, it does not fully bring the RTC ratio for the residential class into the 95-105 percent range. This is largely due to certain cohorts, particularly the higher-usage non-farm cohorts, remaining well below the 95 percent RTC threshold. This fact suggests that it is not merely the declining block rate that is responsible for the relative revenue shortfall from these customers, but rather that these customers' cost of service exceeds that of customers whose usage falls below the second block threshold.[24] For a specific example, consider the case of the moderate usage cohort with monthly consumption between 2,301 kWh and 5,000 kWh compared with the lowest consuming cohort. For these two cohorts, the existence of the declining block rate explains about 22 percent of the initial gap in RTC. The much larger residual difference is due to the underlying distinction in respective cohort costs of service. While the first block rate already produces the target revenue-to-cost ratio of 95 percent for this lowest-consuming cohort, additional rate design changes would be required to generate the needed revenues from the moderate usage cohort.

Declining Block Rates and the Revenue-to-Cost Ratios of Farms

While the case of farms is addressed in detail in the next section, it is worth considering the revenue-to-cost characteristics of farms here. For the large farms with January consumption exceeding 5,000 kWh, the RTC shortfall appears to be entirely explained by the declining block rate. Under the declining block rate, large farms have an RTC ratio of 85 percent (excluding farms that are included in Cohort 7). Without the declining block rate, the large farm RTC ratio exceeds 100 percent. In other words, although the underlying cost of service for large farms included in Cohort 6 is actually lower than other cohorts, the declining block rate structure recovers *even less* than farms' comparatively low cost of service. Again, however, we note that these results should be interpreted cautiously, as some of the customers in Cohort 7 should likely be moved into the farm category, which will impact the final results.

3.2. Recommendations for the Declining Block Rate Structure

Based on the foregoing analysis, we recommend that MECL eliminate the declining block rate structure, as it is not cost reflective. We also support the gradual phasing out of the declining block rate to comport with the principle of gradualism. As shown in Table 3, however, the elimination of the declining block rate structure alone does not bring the RTC ratio for the residential class up to the Commission's

[23] *Ibid.*

[24] While the lowest usage stratum depicted in Table 3 includes customers that benefit from the declining block rate structure, their impact is likely to be nominal on the overall stratum RTC. While not definitive, it bears noting that in Table 2, which provides a more refined stratification of residential customers, the lowest stratum that includes declining block rate beneficiaries (1,200-2,300 kWh per month) provides an RTC that is almost identical to that of the stratum next below (576-1,200 kWh per month).

target range of 95 to 105.[25] To address additional inter-class inequities, we recommend that MECL reexamine the inclusion of large farm customers within the residential class and consider establishing a new rate class once additional load data are available. The following section discusses this last recommendation in detail.

4. Customer Classes

This section examines the rationale for customer classifications and focuses on the special case of farms, which have a long history of taking service on the residential rate despite often having usage characteristics that differ significantly from typical residential customers.

We first discuss considerations for defining customer classes and review key policy considerations that may be used to inform decisions regarding customer classes. We then present the results of a comparative review of farm energy usage characteristics relative to other classes. The aim of this analysis is to evaluate both differences within the farm cohort in energy usage and differences between farms and other customer types, for the purpose of determining which existing rate class is most appropriate for farms, if any. That farms currently take service on the residential rate is a legacy fact, but it need not be maintained indefinitely.

4.1. Defining Customer Classes

Classifying customers into rate classes enhances administrative simplicity while still allowing costs to be fairly allocated. As the Regulatory Assistance Project's recent cost allocation manual explains,

> [T]he purpose of separating customers into broad classes flows from the idea that different types of customers are responsible for different types of costs, and thus it is fairer and more efficient to charge them separate rates. One set of rates for each customer class, based on separate cost characteristics, is the key feature of postage stamp pricing for electric utilities. As a result, it is very important to determine appropriate customer classes with different cost characteristics at the outset of a cost of service study.[26]

All else equal, the members of a rate class should exhibit similar behavior across key dimensions of electricity use, since revenue allocation is based on the class's energy consumption, coincident peak contribution, and non-coincident peak contribution. Similarities across these dimensions is of less importance for intra-class equity as rate structures become more granular, e.g., through time-varying

[25] This target range was established by the Commission in Order UE19-08.

[26] Jim Lazar, Paul Chernick, and William Marcus, "Electric Cost Allocation for a New Era: A Manual" (Regulatory Assistance Project, 2020), 61, https://www.raponline.org/wp-content/uploads/2020/01/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf.

rates and demand charges. More sophisticated rates generally enhance intra-class equity by better recovering costs from customers based on their usage patterns. Conversely, similarities in energy usage patterns within a customer class are more important for equity for rates that only have a fixed and volumetric charge, such as the residential rate schedule.

Another consideration for customer classes is the administrative complexity and implementation concerns associated with establishing additional classes. As the number of classes grows, so does the analytical effort required for cost allocation and review in rate cases. A guideline suggested by the Regulatory Assistance Project's cost allocation manual is that "if more than 5 percent of customers or 5 percent of sales within a class have distinct cost characteristics, differentiation is worth considering. If fewer than that, although the per-customer cost shifts may be significant, the overall impact on other customers will likely be immaterial."[27]

To summarize, rates designed to recover class revenue requirements reflect the average usage characteristics of class members, such that those with significantly divergent usage characteristics (e.g., much lower load factors) end up paying more or less than their fair share.[28] This is particularly true for simple rates without time-varying elements or other rate components. With that said, it is important to recognize that customers within any class are heterogeneous, so some intra-class subsidization is unavoidable.

While there may be compelling reasons why farms have historically been included within Maritime Electric's residential rate class, there is no fundamental reason why they could not be reassigned to another class or separated out into a new class, particularly if their usage patterns more closely resemble that of other classes. Thus, the question of which class farms should be assigned to is best addressed by comparing farm consumption patterns with the consumption of other customers and classes.

4.2. Policy Considerations

While farms are not the only high-use customers included in the residential class, they represent a key constituency at the nexus of the major issues in this proceeding. The discontinuation of the declining block rate structure will substantially increase revenues collected from farms, which will reduce the revenue-to-cost shortfall now associated with the residential class. In addition, the elimination of the declining block rate will help address intra-class inequities, where lower-usage customers are currently subsidizing higher-usage customers. At the same time, avoidance of rate shock is an important policy consideration when modifying rates.

[27] Lazar, Chernick, and Marcus, 64.

[28] More sophisticated modern rate designs can provide more individualized pricing that somewhat relieves the need for customers within given classes to be similar in usage characteristics.

Maritime Electric has also acknowledged the importance of mitigating significant rate impacts to farms in conjunction with any rate design changes. The Company cites Bonbright's fifth principle of ratemaking, related to gradualism, which the Company explains requires that utilities "adjust rates in smaller increments over time to avoid rate shock."[29] Maritime Electric's proposal for a stepwise discontinuation of the declining block rate over four years that will limit average rate impacts to five percent per year is designed to adhere to the gradualism principle.

Although gradualism and avoidance of large detrimental rate impacts is an important principle, there is no consensus on what constitutes rate shock. From our review of regulatory decisions in other jurisdictions, some commissions appear to view increases of 14 percent or more as constituting rate shock,[30] while other commissions have used a threshold of closer to 20 percent.

4.3. Farm Energy Usage Characteristics

High-level Comparison of Farms with Other Customer Types

Many farms use much more electricity than the average non-farm residential customer, and their load curves differ from those of typical non-farm residential customers – both in the general shape of the load curve and in seasonal variability in load curves. Farms are also a more heterogenous group, with greater diversity in consumption among the various farms than is found among other residential customers.

These differences in usage characteristics, suggest that farms should be in a different rate class or a class of their own. To assess whether farms exhibit similar characteristics to other classes, we compared key usage metrics across classes. Table 4 provides a comparison of the average energy and load factors for farms and other customer cohorts.

Table 4. Peak demand allocators

Cohort	Average Monthly Energy (kWh)	Load Factor (CP) (%)	Load Factor (NCP) (%)
Residential excluding farms[1]	792	44	40
All farms (Farm Study)[2]	7,623	67	49
Small industrial[3]	26,504	79	53
General service[3]	4,046	67	61

[1] *Calculated by Synapse using available data*

[2] *Provided in Table 14 of the Farm Study; covers period from July 2019 – June 2020 or calendar year 2017*

[3] *Provided in Maritime Electric response to Synapse Information Request 9; covers calendar year 2020*

[29] Rate design application, p. 28.

[30] For example, the New Mexico Public Regulation Commission found a 14% increase in base rates to be unacceptable in Case 15-00127-UT, while the Washington Utilities and Transportation Commission elected to phase in a large rate increase with a 19% increase being allowed in the first year in Docket UW-180801.

As Table 4 illustrates, farms in the aggregate exhibit load factors that are distinct from both those of non-farm residential customers and those of the small industrial and general service classes.[31] Farms in the Farm Study on average also consume substantially more energy than their non-farm residential peers, although this result is potentially skewed by the selection of larger farms for the farm study.

Review of Load Curves Derived from Farm Study Interval Meter Data

For a more granular view of farm consumption, we constructed load curves using the interval meter data provided by Maritime Electric. While the load factors presented in the table above provide a high-level view of farm energy usage compared with that of other customer types, the load curves enable a more detailed assessment of similarity.

Maritime Electric provided hourly customer load data for 87 farm customers, 410 General Service customers, 68 Residential customers, and 130 Residential-Rural customers collected throughout 2020.[32,33] Synapse was unable to include small industrial customers in this analysis because small Industrial rate class customers are not metered hourly.[34] Synapse used this data to estimate average hourly consumption per customer. Average December 2020 hourly load curves are illustrated in Figure 2 for farms and in Figure 3 for residential and general service customers.[35]

[31] Data from the 2017 Cost Allocation Study, which listed 2,094 farms, suggests that farm load factors may have been similar to residential load factors, but this is contradicted by more recent data presented in the farm study, which listed just 528 farms. Farm load factors estimated using the more recent data are significantly higher than Residential load factors, particularly when estimated using CP load. As a result, the updated Farm CP load factors more closely resemble those of the General Service class. The updated NCP load factors remain closer to those of the Residential class. Individual load factors, which were calculated separately using the hourly meter data discussed above, put the average Farm load factor closer to that of General Service customers than Residential customers.

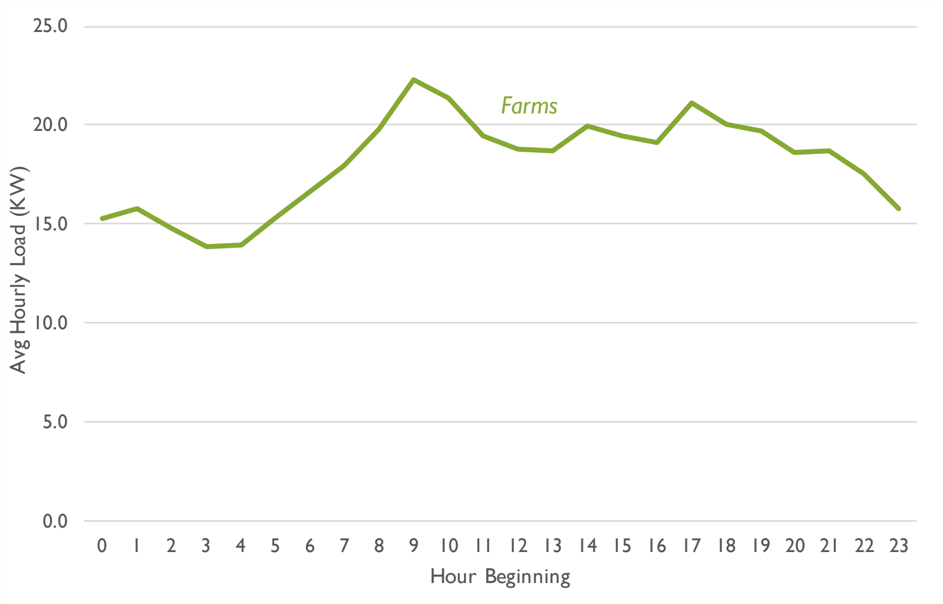
[32] Maritime Electric response to Synapse information request 10 and 15.

[33] Chymko Consulting Limited. 2021. *2020 Cost Allocation Study.* Prepared for Maritime Electric.

[34] Maritime Electric response to Synapse information request 18.

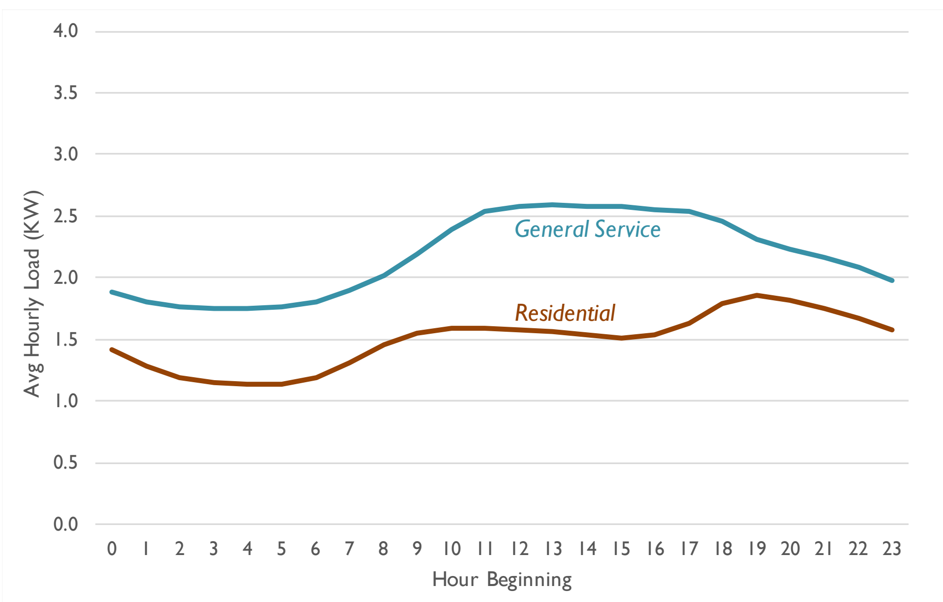
[35] Historically, MECL's system has generally peaked in December.

Figure 2. December 2020 average load curve for farms



Source: Synapse analysis of data provided in Maritime Electric response to Synapse IR-10.

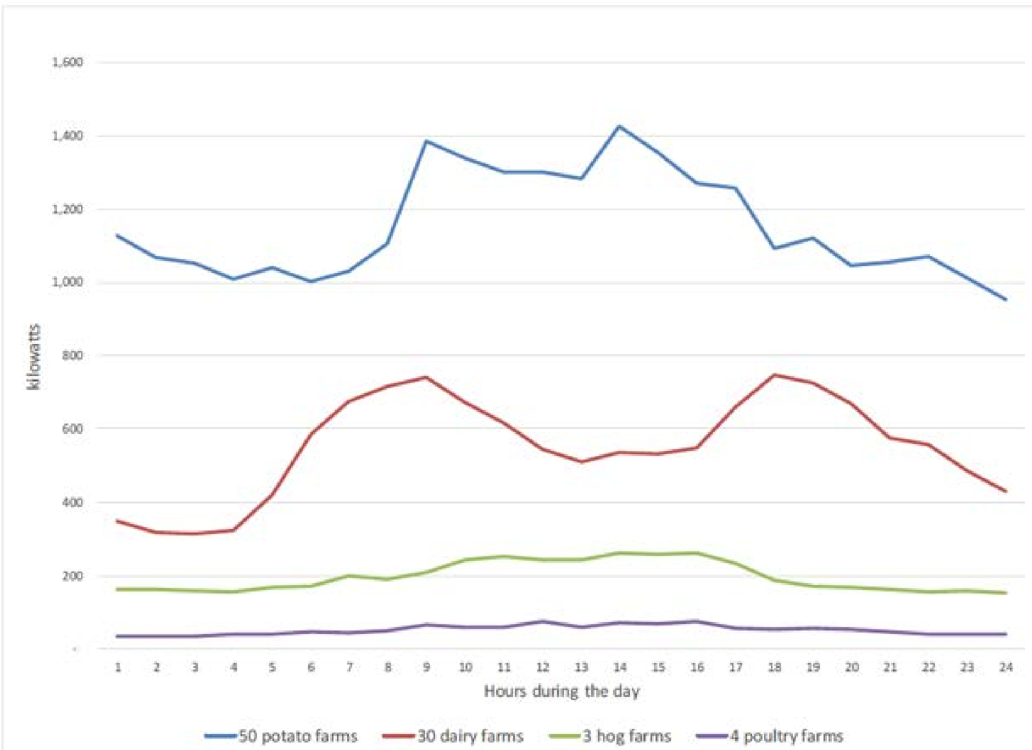
Figure 3. December 2020 average load curve for general service and residential customers



Source: Synapse analysis of data provided in Maritime Electric response to Synapse IR-15. Residential Class is calculated as the customer-weighted average of the Residential Urban and Residential Rural load curves.

A key difference in the load curves is the magnitude, with farm usage dwarfing the average residential and general service customers. In addition, farm usage tends to peak in the morning, with evening usage is not as high as the general service or residential classes. Data presented by MECL in the June 2020 draft of the Farm Study[36] suggest that the shape of the aggregate farm load curve obscures much of the heterogeneity in usage across farm types. The figure below shows hourly loads for a sample of farms grouped by type on the 2018 system peak day. [37] Potato farms and dairy farms appear to have potentially offsetting usage, with the dairy load curve peaking in the early morning and late evening while potato farms reach their maximum in the middle of the day. Based on this disaggregation of farm load curves, potato farm usage more closely resembles the general service load curves while dairy farm usage is resembles the residential load curve, particularly in its bimodality.

Figure 4. Hourly farm loads for December 27, 2018 - day of system peak



Source: Farm Rate Study (June 2020 Preliminary Draft), Chart 7-2

Farm Customer Bill Impacts of Various Rates

In addition to considering load profiles, it is important to understand expected bill impacts for farms from any change in rate class or design. Maritime Electric provided an analysis of these impacts for Potato and Dairy farms caused by either the eliminating the declining block of the residential rate or by converting to the small industrial tariff. Synapse supplemented this analysis by updating the rate schedules to align with current rates (2021) and by adding bill impacts caused by converting farms to the

[36] Farm Rate Study (June 2020 Preliminary Draft), Filed as Appendix C to the Electric Rate Design Study, prepared by Robert Boutilier, June 29, 2020.

[37] *Id.* Appendix C, Chart 7-2, p. 87.

general service class. The results are shown below in Figure 5 (for potato farms) and Figure 6 (for dairy farms).

Figure 5. Estimated increases in annual electricity bills for each of 50 potato farms

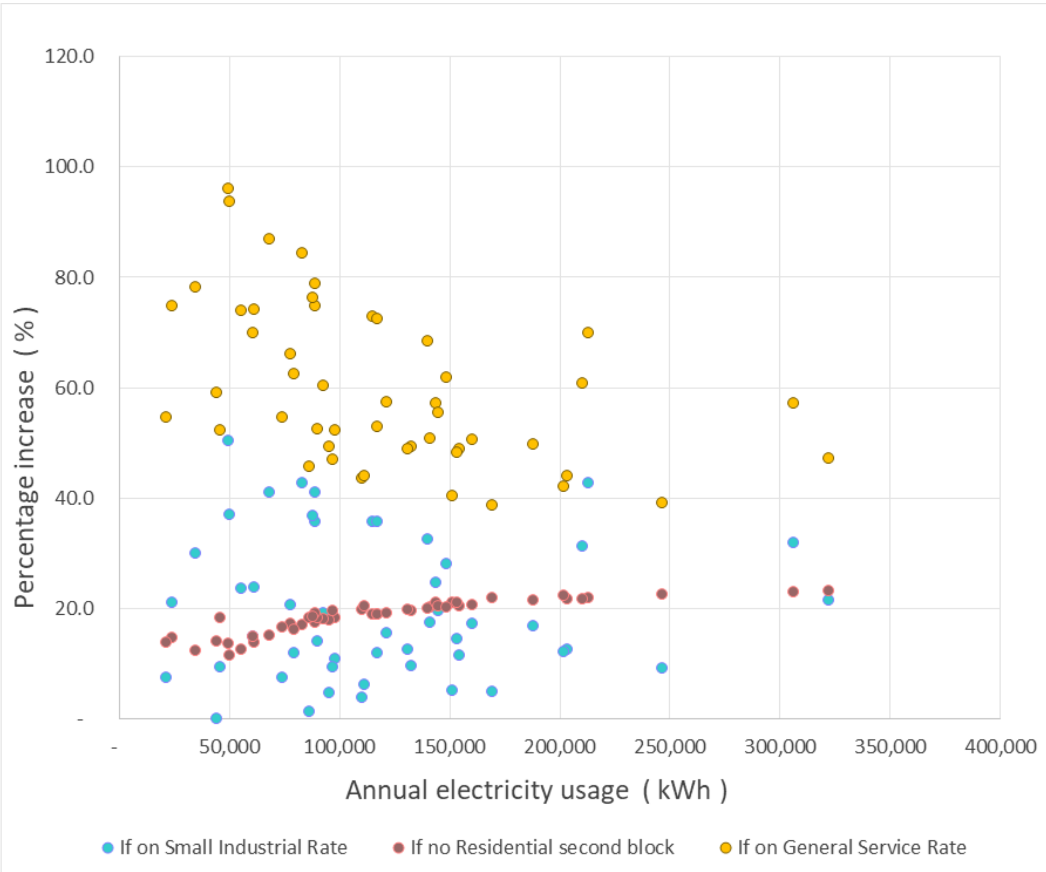
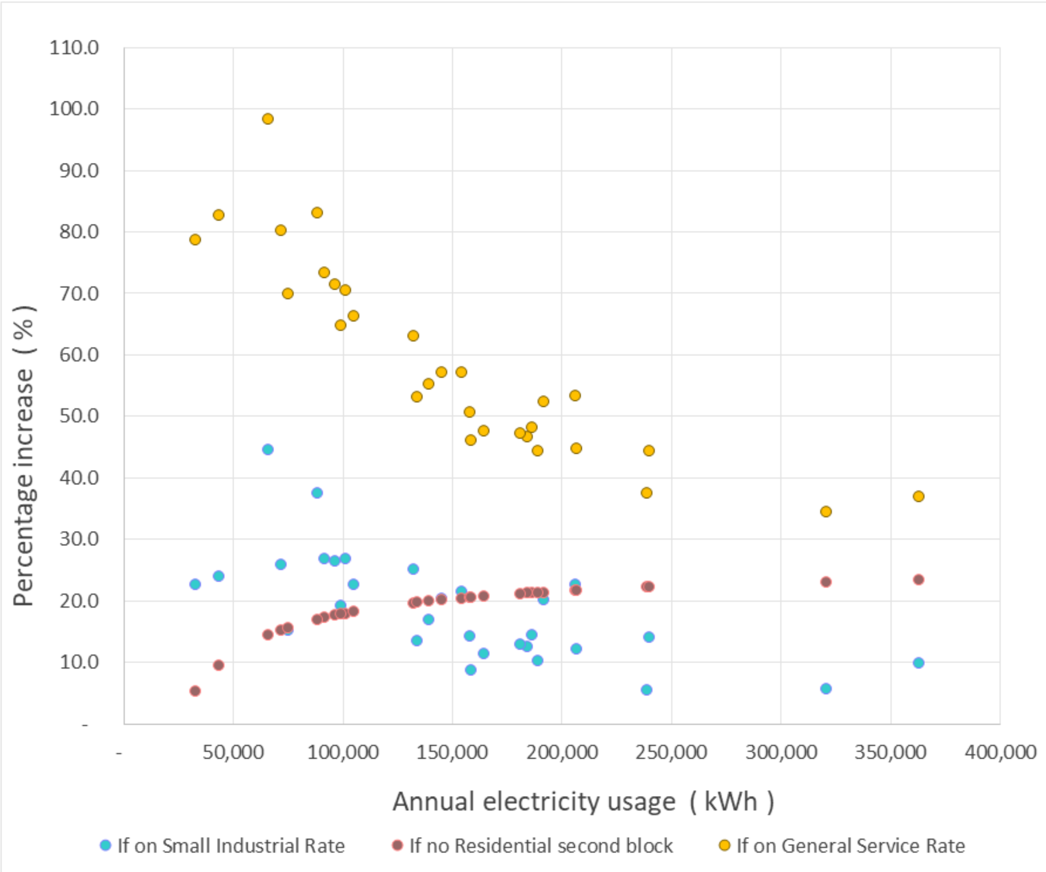


Figure 6. Estimated increases in annual electricity bills for each of 30 dairy farms



Both figures illustrate that in all instances farm customers can expect increases in their electricity bills, but it appears that migrating farm customers to the general service rate would increase bills the most. In general, remaining on the restructured residential rate is likely to have the lowest bill increases for customers with lower annual electricity usage, while converting to the small industrial rate will generally minimize bill impacts for customers with higher usage. This relationship is more apparent for dairy farms than for potato farms, in part because the former have much more consistent peak demand while the latter tend to exhibit greater variation by customer. The result is that the demand charge used in the small industrial rate appears to result in greater disparities in bill impacts for potato farmers with similar energy usage.

4.4. Characteristics of Customers in Cohort 7

MECL characterizes the 45 customers in Cohort 7 as "Other >5,000 kWh". Although the Cohort 7 customers comprise only 0.1 percent of MECL's customer base, they consume 0.8 percent of total energy and were allocated 1.0 percent of total costs in 2017. Many customers fall into this cohort rather than into farm or domestic groupings because MECL's Residential Service Rate Application Guidelines allow the residential rate to apply to farms and churches, premises providing lodging with nine beds or less, and a business combined with a dwelling where the connected business load excluding space heating and air conditioning, is two kW or less.[38]

The 45 customers in Cohort 7 can be further divided into six customer categories, as shown in Table 5, below.[39]

Table 5. Cohort 7 categories and characteristics

Category	Number of Customers	Avg Customer kWh/Month
Cannabis operations	2	407,448
Fish farms	3	50,061
Agricultural-related operations	9	19,101
Religious organizations	16	5,028
Government housing facilities	4	5,618
Miscellaneous commercial operations	11	4,057

Source: Response to Synapse IR-2, Attachment 1, March 2, 2022.

Two important observations are immediately apparent from this table. First, cannabis operations, fish farms, and agricultural-related operations use many times as much electricity as the remaining categories and the average domestic customer.[40] In fact, the cannabis operations appear to consume approximately 500 times as much energy as the average domestic customer.

Second, customers in the first three categories (cannabis, fish farms, and agricultural-related operations) may be improperly categorized in Cohort 7 and should be moved to Cohort 6 (large usage farms). MECL's Schedule of Rates and General Rules and Regulations defines a farm as "a holding on which agricultural operations are carried out. Agricultural operations include the production of field crops including grain, vegetables, seed and forage crops; animal and dairy products including milk, cream, eggs, meat and poultry products, poultry hatcheries, nurseries and greenhouses for the production of crops or bedding plants, fur farms apiaries, fish hatcheries and fish farms."[41] As such, all of the customers in the first three categories appear to meet the definition of farms, and should therefore be included in Cohort 6 with other large farm customers.

Because the customers in the first three categories (cannabis operations, fish farms, and agricultural-related operations) consume approximately 90 percent of the electricity of Cohort 7, their

[38] MECL. Rates and General Rules and Regulations, effective March 1, 2022. https://www.maritimeelectric.com/about-us/regulatory/rates-and-general-rules-and-regulations/

[39] Response to Synapse IR-2, Attachment 1, March 2, 2022.

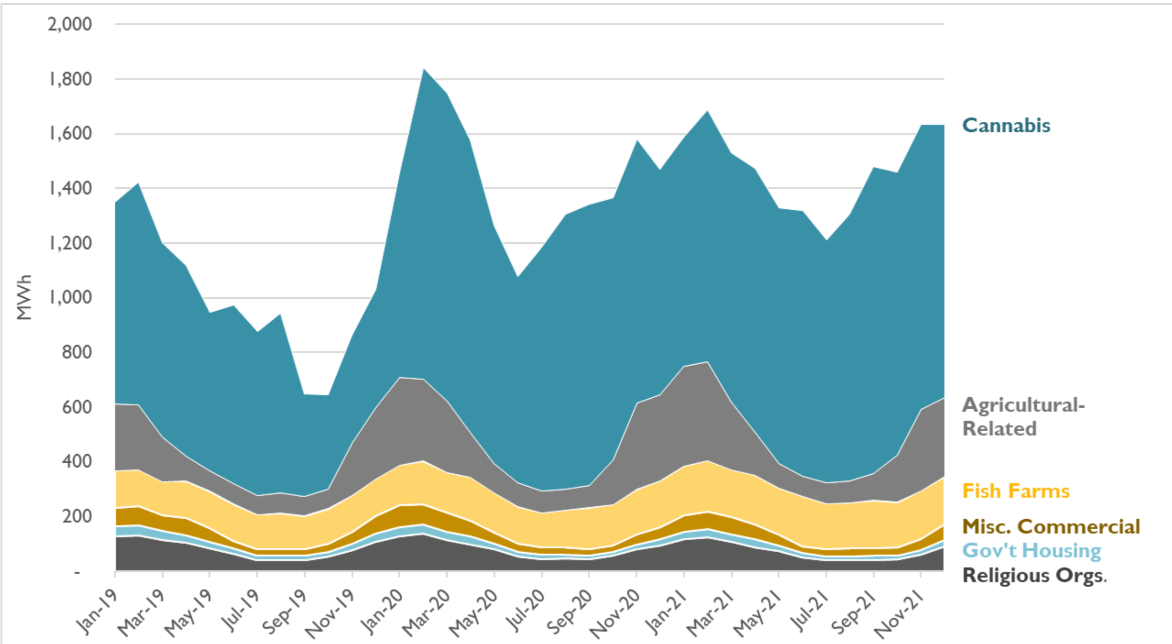
[40] The average monthly usage for a domestic customer is approximately 800 kWh.

[41] Response to Synapse IR-1 (a), March 2, 2022.

reclassification into Cohort 6 is likely to have a significant impact on the RTC ratios for both Cohort 6 and Cohort 7 (provided that their CP and NCP loads are properly measured).

Since 2017, the energy usage of Cohort 7 has grown rapidly, from 10.5 GWh in 2017 to 17.4 GWh in 2021, primarily due to cannabis operations load.[42] Monthly load for 2019-2021 for each category of Cohort 7 is shown in the figure below.

Figure 7. Total monthly load for cohort 7 customer categories (2019-2021)



Source: MECL Response to Synapse IR-2, Attachment 1, March 2, 2022.

Based on the Company's analysis, Cohort 7 has the lowest RTC ratio of any residential class cohort at 65.1 percent. Continued load growth in Cohort 7 is likely to worsen intra-class inequities, even with the elimination of the declining block rate, since the RTC ratio is projected to only improve to 80.7 percent, as shown in Table 3. As noted above, MECL has very little interval metering data for the customers in Cohort 7, so it is difficult to discern whether all of the customers in Cohort 7 have relatively poor load factors, or whether this is unique to the largest customer.

4.5. Recommendation for Customer Classes

The characteristics of farms in Cohort 6 and Cohort 7 indicate that large farms use electricity in significantly different ways than domestic customers. These usage patterns, particularly under the declining block rate, have contributed to low revenue-to-cost ratios. Although elimination of the

[42] MECL Rate Design Application, Appendix C - Preliminary Residential Class Load Study Results, Table 3, p. 7, and Response to Synapse IR-2, Attachment 1, March 2, 2022.

declining block rate would address RTC ratio deficiencies for Cohort 6, it does not fully address these issues for Cohort 7. As discussed above, if the largest user in Cohort 7 were included with Cohort 6, the RTC ratio for large farms would decline by several percentage points. The inclusion of other farm customers from Cohort 7 into Cohort 6 may further worsen the RTC ratio, although this should be verified through additional load research studies.

Overall, these findings support the proposition that farms, including cannabis operations, be separated into a new rate class. When considering whether to establish a new rate class, we note that based on 2017 data, farm energy consumption totals about 3.5 percent of all energy sales on Maritime Electric's system,[43] with the bulk of this energy usage is attributable to large farms (with January 2020 usage greater than 5,000 kWh).[44] This puts the large farms cohort slightly below the suggested threshold for creating a new class discussed above. However, the addition of farm customers from Cohort 7, particularly cannabis operations customers, suggest that large farm customers may now exceed the 5 percent threshold for energy sales.

The prospect of segregating large farms into their own rate class is complicated by the fact that most customers in Cohort 7 do not have interval metering, thereby making it impossible to determine the cost to serve these customers using standard CP and NCP measures. Further, although MECL claims that the load data for customers in the farm study is likely to be a reasonable approximation of large farms overall,[45] we suggest that additional load meters be installed to verify this.[46] The installation of additional load meters will take time, and therefore the development of a new rate class cannot be accomplished using accurate load data in the near term. However, it is reasonable to expect that sufficient data will be available after two years' time to inform the establishment of a new rate class. We note that while it is customary to adjust rates at the same time, or in short succession, to examining a utility's revenue requirement, it is not necessary to conduct a full rate case to design and implement new rates.

In the interim, we recommend that the Company implement its phased proposal for eliminating the declining block rate. Although we acknowledge that the Company's optionality proposal that would allow customers to choose to take service on the small industrial rate has appeal due to the mitigation of rate impacts, we are concerned that it would not sufficiently further the adoption rates that are more cost-reflective, since the small industrial tariff was not designed based on large farm load curves.

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[43] MECL Rate Design Application, Table 2, p. 22.

[44] Large farms constitute approximately 69% of the 2017 costs allocated to all farm customers, and 76% of energy sales to all farm customers. Calculated using data from MECL Rate Design Application, Table 2, p. 22, and MECL Rate Design Application Appendix C, Preliminary Residential Class Load Study Results, Table 3, p. 7.

[45] MECL Rate Design Application, Appendix A - Farm Study, May 21, 2021, p. 26.

[46] The Company indicates that additional residential load research meters cost approximately $200 for materials and installation. Response to Synapse IR-3(f), March 2, 2022.

5. RESIDENTIAL SERVICE CHARGE

5.1. Maritime Electric's Current Service Charge

Maritime Electric currently assesses a monthly residential service charge of $24.57 for urban customers and $26.92 for rural customers. This service charge is among the highest residential customer charges of investor-owned utilities in North America.[47] The first step in assessing the reasonableness of this service charge was to review Maritime Electric's methodology for classifying costs as customer-related (versus demand- or energy-related). For the past 30 years, Maritime Electric has used the percentages in Table 6 below for the percentage of distribution costs in each category classified as customer-related (also referred to as "site-related").[48]

Table 6. Percentage of distribution costs classified as customer-related

	Primary Distribution Lines	Distribution Transformers	Secondary Lines
Customer-Related	50%	40%	50%

Source: Response to Synapse IR-4.

However, the Company could not explain or produce the calculations for how these percentages were developed,[49] but rather has simply employed them as its default assumptions for the past three decades. This has resulted in substantial costs being recovered from high customer charges, without justification for this approach.

5.2. Classification of Customer-Related Costs

Professor James Bonbright defines customer-related costs as "those operating and capital costs found to vary with number of customers regardless, or almost regardless, of power consumption."[50] However, defining these costs can be controversial. Some analysts use a "minimum system" method (or the closely-related "zero-intercept method"), which classifies costs by estimating the cost of building from scratch a hypothetical system employing the smallest size components typically installed, and then deeming those costs customer-related. This method results in a portion of the distribution system (e.g., secondary lines) classified as customer-related and can lead to relatively high customer charges. Other analysts take a more constrained approach and include only the costs directly related to connecting a customer to the system and providing customer service. This method is referred to as the "basic

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[47] Synapse review of rates in the NREL Utility Rate Database (https://openei.org/wiki/Utility_Rate_Database).

[48] Response to Synapse IR-4 and IR-6.

[49] Response to Synapse IR-6.

[50] James Bonbright, *Principles of Public Utility Rates* (New York: Columbia University Press, 1961), 341.

customer" method, under which only the meter, service drop, and billing/collection costs are typically classified as customer-related.

Maritime Electric's approach adopts a very broad definition of customer-related costs. Under the Company's method, a portion of both the secondary distribution system and primary distribution lines are classified as customer-related. Inclusion of a substantial portion of the primary distribution lines in the customer-related costs is somewhat unusual. According to a 2017 review of cost allocation methodologies by Elenchus Research Associates, half of surveyed utilities did not classify any portion of primary lines as customer-related. Only 20 percent of the utilities classified 50 percent or more of primary distribution line costs as customer-related.[51] The table below presents a comparison of the percentage costs in each category that are classified as customer-related for each utility surveyed by Elenchus Research Associates and Maritime Electric.

Table 7. Comparison of distribution costs classified as customer-related

Utility	Primary Lines	Distribution Transformers	Secondary Lines
BC Hydro	0%	50%	0%
ATCO	0%	50%	70%
Manitoba Hydro	0%	0%	0%
Hydro One	50%	62%	50%
Hydro Quebec	0%	0%	23%
NL Power	33%	21%	33%
NB Power	50%	25%	50%
NS Power	27%	0%	50%
Georgia Power	16%	0%	25%
Consumers Energy	0%	0%	0%
Maritime Electric	50%	40%	50%

Source: Based on data included in the Elenchus Research Associates, June 2017 report.

The table indicates that the portion of costs that Maritime Electric classifies as customer-related is on the high end of the surveyed utilities, second only to Hydro One.

5.3. Results of Alternative Classification Methods

Maritime Electric provided the cost categories used to calculate total customer-related costs for its 2017 cost allocation study, as shown in the table below. Using these data and assuming that the costs

[51] John Todd and Michael Roger, "Review of Cost Allocation and Rate Design Methodologies" (Elenchus Research Associates, Inc., June 30, 2017), https://www.saskpower.com/-/media/saskpower/accounts-and-services/rates/cost-of-service/report-rates-elenchus-reviewcostallocation-ratedesign-june2017.ashx.

assigned to each class for each category are held constant,[52] we calculated the customer charge under various classification percentages. Under the Company's method in which 50 percent of primary lines are classified as customer-related, the resulting value suggests a residential customer charge of $24.61.

Table 8. Company's methodology for customer charge

Distribution System Category	Reference	Residential Customer-Related Costs ($000s)	Residential (S) Customer-Related Costs ($000s)	Farms Customer-Related Costs ($000s)	% Customer
Primary lines		5,204	682	190	50%
Distribution transformers		3,049	399	111	40%
Secondary lines		1,802	236	66	50%
Service lines		4,400	683	161	100%
Meter assets		955	125	35	100%
Meter reading		655	49	24	100%
Billing		721	54	26	100%
Remittance & collection		523	39	19	100%
Uncollectibles & damage claims		357	47	13	100%
Service connections		(266)	(27)	(10)	100%
Late payments		(485)	(15)	(18)	100%
Total Annual Cost ($000s)	**A**	16,915	2,272	619	
Average # bills/mo	B	57,286	7,504	2094	
Average monthly costs ($/mo)	**C = A/B/12**	24.61	25.23	24.62	

If primary lines are removed from the customer-related costs, holding all else equal, the implied residential customer charge falls to $17.04.

[52] Changing the classification methodology will generally result in changes to class cost allocations. These impacts are addressed in the next section.

Table 9. Impact of removing primary lines from customer-related costs

Distribution System Category	Reference	Residential Customer-Related Costs	Residential (S) Customer-Related Costs	Farms Customer-Related Costs	% Customer
Primary lines		0	0	0	0%
Distribution transformers		3,049	399	111	40%
Secondary lines		1,802	236	66	50%
Service lines		4,400	683	161	100%
Meter assets		955	125	35	100%
Meter reading		655	49	24	100%
Billing		721	54	26	100%
Remittance & collection		523	39	19	100%
Uncollectibles & damage claims		357	47	13	100%
Service connections		-266	-27	-10	100%
Late payments		-485	-15	-18	100%
Total Annual Cost ($000s)	**A**	11,712	1,590	428	
Average # bills/mo	B	57,286	7,504	2094	
Average monthly costs	**C = A/B/12**	17.04	17.66	17.05	

Under the basic customer method, no portion of the secondary or primary distribution system is classified as customer-related. The table below indicates that under this methodology, the implied customer charge would be $9.98/month for residential customers.

Table 10. Impact of basic customer approach on customer charge

Distribution System Category	Reference	Residential Customer-Related Costs	Residential (S) Customer-Related Costs	Farms Customer-Related Costs	% Customer
Primary lines		0	0	0	0%
Distribution transformers		0	0	0	0%
Secondary lines		0	0	0	0%
Service lines		4,400	683	161	100%
Meter assets		955	125	35	100%
Meter reading		655	49	24	100%
Billing		721	54	26	100%
Remittance & collection		523	39	19	100%
Uncollectibles & damage claims		357	47	13	100%
Service connections		-266	-27	-10	100%
Late payments		-485	-15	-18	100%
Total Annual Cost ($000s)	**A**	6,860	955	251	
Average # bills/mo	B	57,286	7,504	2094	
Average monthly costs	**C = A/B/12**	9.98	10.60	9.99	

5.4. Impacts on Class Cost Allocation

The foregoing discussion highlighted the changes to the implied customer charge when a smaller proportion of distribution costs are classified as customer-related. However, the analysis presented held allocated costs fixed for each class. Yet a change to classification will also impact the costs allocated to each customer class, which will in turn impact the revenue-to-cost ratios, as well as the unit costs. Typically, classifying costs as customer-related results in a larger portion of costs being allocated to the residential class because this class tends to have the greatest number of customers. If costs are instead classified as demand-related, the relative cost allocation to the residential class may decline, depending on the shape of each class's aggregate load profile.

To illustrate the impact on cost allocation, Synapse adjusted the allocators in Maritime Electric's 2017 Cost Allocation Study to follow the basic customer method. In performing this change, we assumed that distribution costs would instead be classified as 100 percent demand related, based on class non-coincident peak demand. This analysis is meant to be illustrative and is not meant to imply that this is the only acceptable alternative classification approach.

The results of classifying primary and secondary distribution costs as 100 percent demand-related are shown in the table below. As expected, the change results in a lower proportion of costs being allocated to the residential class and a larger share of costs being allocated to the farm, general service, small industrial, and large industrial classes. The RTC ratios also change, with the residential class improving to 94 percent and the farm class declining to 78 percent. In addition, the RTC ratios for the general service, small industrial, and large industrial classes also worsen, although the general service class is still paying more than its cost of service.

Table 11. Results of changing classification of distribution costs on class cost allocation

	Revenue Collected	Allocated Cost		Revenue to Cost Ratio	
	2017	2017 CAS Method	Basic Customer Method	2017 CAS Method	Basic Customer Method
Residential	45.9%	50.3%	48.9%	91.4%	94.0%
Farm	3.8%	4.6%	4.8%	82.1%	78.0%
General Service	31.9%	26.2%	27.6%	121.5%	115.2%
Small Industrial	6.4%	6.2%	6.9%	102.4%	92.0%
Large Industrial	7.2%	7.7%	7.9%	93.6%	91.6%
Lights	1.3%	1.4%	1.0%	91.1%	129.5%
Unmetered	0.2%	0.2%	0.2%	104.3%	113.9%

Because the costs allocated to each class have changed, the resulting unit costs also change slightly. For residential customers, the total revenue requirement divided over the total class sales falls from 18.17 ¢/kWh to 17.68 ¢/kWh.

5.5. Recommendations Regarding the Residential Service Charge

Maritime Electric's assumptions regarding the portion of costs that should be classified as customer-related is unsupported and results in an outsized portion of costs being classified as customer-related. This also results in a greater apparent revenue shortfall (and lower RTC ratio) for the residential class. Synapse recommends that the Company undertake an analysis of its costs and propose a new method for classifying distribution costs based on the results of its analysis. Although various methods could be used to perform this calculation, Synapse recommends using the basic customer method over the minimum system method for the reasons discussed below.

First, as established in the preceding sections, low-usage residential customers are contributing more than their fair share to revenues. All else equal, a lower customer charge will reduce bills for lower-usage customers and increase bills for higher usage customers, since more costs will need to be recovered through the volumetric charge. This result is consistent with the data regarding cost causation.

Second, the basic customer method is widely used and, according to the Regulatory Assistance Project, "is by far the most equitable solution for the vast majority of utilities."[53] Key critiques of the minimum system method from the Regulatory Assistance Project's manual are summarized below:

1) The hypothetical "minimum system," used as the basis for this cost allocation method, still has the ability to serve some load—often a large portion of a typical residential customer's load. Without correcting for this, the minimum system overstates the customer-related costs.

2) A large portion of the cost of the distribution system (e.g., the number of poles and length of conductors) is driven by the size of the territory served, rather than the number of customers.

3) The minimum system method generally uses commonly installed minimum sizes, rather than the smallest equipment ever used, currently in use, or that could be used. However, a key reason for using larger equipment is due to higher customer demands, and thus the minimum size currently in use does not represent the true minimum that would be required for a hypothetical minimum system.

4) The hypothetical minimum system is assumed to have the same number of units (number of poles, feet of conductors, etc.) as the actual system. In reality, both the size of equipment and the number of units is often driven in part by load.

5) Increasing the number of customers in an area without increasing demand can be accomplished with no additional poles or conductors.

[53] Lazar, Chernick, and Marcus, "Electric Cost Allocation for a New Era: A Manual," 145.

The manual concludes that the "minimum system analysis does not provide a reliable basis for classifying distribution investment and vastly overstates the portion of distribution that is customer-related." [54]

Finally, it is our understanding that Maritime Electric has not conducted a minimum system analysis and doing so would require time and resources that may not be available prior to the Company's filing of its next rate case. For all of these reasons, Synapse recommends that the Company implement the basic customer method to inform its next rate adjustments.

6. Advanced Rate Designs

6.1. TOU Rates

Maritime Electric's rate design study (the "Boutilier Study") did not identify or recommend any alternative rate designs, such as TOU rates, for the near term, but it did suggest that such rates could be beneficial to manage system peak demand over the longer term as more customers adopt electric vehicles. In addition, the Company noted in its application that it is currently unable to implement advanced rate designs such as TOU rates due to metering and billing system constraints.[55]

Aside from technological constraints, the Company's rationale for not pursuing TOU rates or other advanced rate designs in the near-term is that its energy supply costs "do not vary significantly between peak hours and off-peak hours,"[56] and would therefore not be beneficial for customers. However, the Company did not explicitly address the potential benefits of reducing peak demand in the near-term, as it apparently views these costs as "fixed costs."[57]

In response to information requests regarding the fixed nature of its capacity costs, the Company explained that it purchases capacity from NB Energy Marketing (NBEM) as part of its five-year Energy Purchase Agreement for the duration of the contract. If its required capacity is lower than projected, the Company would enter into discussions with NBEM regarding amending the contract, if NBEM is in a position to do so. This response indicates that there could be cost savings from reducing system peak demand even in the near term, although such savings are uncertain. However, the Company's response did not address potential cost savings from deferring or avoiding additional transmission and distribution costs on its system, particularly investments required to support local increases in peak load (e.g., at the substation or feeder level).

[54] Lazar, Chernick, and Marcus, 146.

[55] MECL Rate Design Application, at 43-44.

[56] MECL Rate Design Application, at 43-44.

[57] MECL Rate Design Application, at 23.

6.2. Recommendations Regarding Alternative Rate Designs

Although the Company's installed technology currently limits its ability to offer advanced rate designs, the Company notes that it is conducting research for upgrading its metering infrastructure and plans to also upgrade its billing system in the near future.[58] To thoroughly evaluate the cost-effectiveness of such investments, a full accounting of the potential benefits of advanced rate designs is required. Thus, Synapse recommends that the Company obtain additional price quotes from NBEM for varying levels of capacity requirements, as well as assess the potential benefits of avoiding or deferring capacity-related investments on the transmission and distribution system. The latter analysis could take the form of a marginal cost study, or a more detailed assessment of forecast capacity needs and associated costs.

7. CONCLUSIONS AND RECOMMENDATIONS

In light of the above analysis, Synapse agrees with the Company's proposal to eliminate the declining block rate structure for the residential class. Doing so would significantly enhance cost reflectivity and the residential RTC ratio. Further, Maritime Electric's suggested approach to eliminating the declining block structure in staged fashion comports with the principle of gradualism and should be adopted.

Our analysis of large farms' usage characteristics suggests that these customers use electricity in significantly different ways than domestic customers. This suggests that creation of a separate rate class is reasonable and warranted. However, the lack of interval metering data, particularly for customers in Cohort 7, makes the development of cost-reflective rates for this group of customers difficult. We recommend that Maritime Electric install additional load research meters so that it can gain a better understanding of the usage patterns of large farm customers.

We also recommend that the method for determining the residential service charge be reexamined. The high residential service charge is not rooted in cost causation and does not promote energy conservation, thereby contravening two important rate design principles. To provide customers with more efficient price signals and enhance fairness, Synapse recommends adoption of the basic customer method for allocating costs and determining the service charge.

In addition, we note that alternative cost classifications result in different implied service charges, as well as different class cost allocations. Reducing the service charge increases the volumetric rate, resulting in lower revenues being collected from lower-usage customers and higher revenues being collected from higher-usage customers, all else held equal. Thus, this could better balance the RTC ratios across residential sub-cohorts. Alternative cost classification methods will likely also impact the residential class's RTC ratio.

[58] MECL Rate Design Application, at 45.

Finally, we recommend that Maritime Electric continue to explore alternative rate designs, such as time-varying rates. Time-varying rates can help to constrain increases in system costs, or even to decrease system costs on a forward-going basis. Without more sophisticated price signals, peak demands on the system are likely to exceed efficient levels, resulting in higher costs for all customers. Thus, the Company should assess the potential cost savings associated with reducing system peak demand, as well as assess the potential benefits of avoiding or deferring capacity-related investments on the transmission and distribution system, and design rates that convey this information to customers through actionable price signals.