UE22503 – MECL Rate Design Application

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Author Profile

Melissa Davies of MNYD Consulting Inc. has worked in utility economic regulation for over 15 years. Melissa's experience covers seven different Canadian jurisdictions, working for regulators, utility companies, large industrial customer groups, and small residential and small business intervenors. Melissa has been primarily involved in rate proceedings involving revenue requirement, cost of service, rate design, and integrated resource planning. Melissa has provided expert evidence in six proceedings. Melissa holds an MBA in Finance and Sustainability.

Patrick Bowman of Bowman Economic Consulting Inc. has over 25 years of utility regulatory experience covering all aspects of utility economic regulation. He has been accepted as expert in utility regulation for the purposes of testimony in almost every province and territory in Canada, providing oral testimony on approximately 40 occasions.

Table of Contents

1. Introduction and Executive Summary

This Pre-filed Testimony has been prepared for the Prince Edward Island Federation of Agriculture ("PEIOFA") jointly by Melissa Davies of MNYD Consulting Inc. and Patrick Bowman of Bowman Economic Consulting Inc. Their CVs are provided in Appendix B.

For this Pre-Filed Testimony, Ms. Davies and Mr. Bowman were asked to identify and evaluate potential issues of concern and opportunities for farming customers of Maritime Electric Company Limited ("MECL"), arising from the MECL Rate Design Application ("Application" or "RDA" - Exhibit M-1), filed before the Prince Edward Island Regulatory & Appeals Commission ("IRAC") on May 14, 2021.

In preparing this testimony, Ms. Davies and Mr. Bowman relied on the following materials in addition to the record in UE22503:

- Order UE10-03
- Order UE16-04R
- Order UE19-08
- Select materials filed in the following proceedings, where relevant and referenced within this report, including:
    - UE20946 MECL 2023 General Rate Application
    - UE20227 MECL 2020 Integrated System Plan
    - UE 20944 MECL 2018 General Rate Application
    - UE20742 Supplemental Capital Budget Request for MECL's On-Island Capacity for Security Supply Project
    - PEI's 2016 Energy Strategy and Ongoing Energy Blueprint
    - PEI Energy Corporation's (PEIEC) most recent Energy Efficiency and Conservation Plan for 2022/23 – 2024/25
- UE21232 MECL 2023 Cost Allocation Study ("CAS") filing under both Status Quo methods (See Appendix A to this submission) as well as under the novel Alternative Methods produced by MECL.

The Application anticipates that rate redesign activities would be undertaken in two stages, with approvals for only Stage 1 being sought within this proceeding.[1] As a result, this pre-filed testimony primarily addresses the requests made by MECL related to Stage 1, with some comments on areas to pursue and process for Stage 2 (in Section 5).

The Stage 1 approvals sought by MECL are set out in the Application Exhibit M-1 at Section 11; however, these proposals are now extremely dated (from 2021) and are based on the results of a 2017 Cost Allocation Study that has been superseded by multiple updates. It is understood that MECL is continuing to seek approval to apply the same principles as outlined in those requested

[1] Exhibit M-1, pages 36-37.

approvals, presumably updated to current factual context, which are anticipated to include the following:

1) Elimination of the Residential Second Block over a period of 4 years, by increasing the second block rate in steps to equalize with the then-prevailing first block rate.
2) Permitting farms, who elect to incur the cost of splitting their residential and farm loads into two metered services, and whose farm load is large enough to qualify, to have their farm load included in the Small Industrial rate class (with the residential portion of the load remaining on the Residential rate class). The timing of this customer “choice” within the 4 year transition period is unclear based on MECL’s Application.
3) Increase the rates for other classes which are below 95% Revenue-To-Cost (“RTC”) ratio, over a period of 1 to 2 years (originally anticipated to be Large Industrial and Lighting).
4) Use added revenues from steps 1 and 3 to lower the rates to the General Service class, such that the rate changes are revenue-neutral to MECL.
5) Continue to generate load data from the Residential, Farm and General Service load research studies, which would permit a future rate redesign of the General Service class (part of a future Stage 2 of the process).

Additional recommendations were provided by Mr. Boutilier,[2] who was retained by MECL that have not been adopted by MECL and are not generally further evaluated in this submission. In addition, the Board’s consultant, Synapse Energy Economics (“Synapse”), has provided additional recommendations,[3] two of which are addressed in this submission.

MECL’s farm customers comprise approximately 2,000 customers who are presently served in the Residential class. Of this group, approximately 1,500 customers do not routinely use over 2,000 kWh per month (“small farms”), and as such have a load size that is similar to other residential customers. This group of 1,500 customers will not be materially adversely affected by the MECL Stage 1 proposal.

The remainder of the farm customers, comprising approximately 500 customers (“large farms”) are presently served in the Residential class, but do not have usage characteristics comparable to a residential customer.

1.1 Summary of Conclusions and Recommendations

Based on a review of the available materials, the following conclusions and recommendations are drawn, as further described in the remainder of this submission.

First and foremost, IRAC has had a long-held concern that the Residential class is underpaying (i.e., being subsidized) by way of the General Service class, and that large farms are among the most problematic loads in the Residential class. The latest data confirms that while the General Service rate class is overpaying its costs, it is not subsidizing large farms. Were the MECL

[2] Exhibit M-1(a).
[3] Exhibit C-4

recommendations regarding second block Residential rates to be adopted, farms would be paying an RTC of 114%, well above the target range of 95% to 105%.[4]

The conclusion that large farms were being subsidized was based on incorrect assumptions about farm loads, and about dated system conditions, that were changing at the time reporting was first filed in this proceeding (2020 – 2022), and now no longer exist. This is discussed more in Section 1.2.

The conclusions and recommendations arising from the materials now available are as follows:

- The IRAC concern that certain classes (particularly General Service) are paying more than their measured costs (i.e., RTC above 105%), while others (particularly Residential and Lighting) are paying less than their measured costs, remains broadly valid. Rebalancing to address this concern is justified. [see Appendix A]
- Upward rate adjustments to the Residential (with Farms removed) and Lighting classes are merited, permitting reductions to the General Service class. [see Appendix A]
- The situation of large farms is not consistent with the remainder of the residential class where they are presently included. This is a notable change from the facts presented to IRAC in the 2008 – 2020 time period, representing three significant developments:
    - The large farm customers have now been monitored, and it is confirmed that their load profiles are materially different than the remainder of the Residential class. In particular, this is because the customers are larger than average residential customers, and tend to use their highest amount of energy and peak demand at times when the system is less constrained (particularly summer and fall). [see Section 3.2]
    - The remainder of the Residential class has evolved to have even more concentrated load at peak times (e.g., through increased heating load), driving a need to recover material costs related to "Coincident Peak" (CP) loads in January/February through their energy rate. This same feature does not apply to large farms given their lesser relative use of coincident peak. [see Section 3.2]
    - The relative cost of demand on the system has increased faster than the relative cost of energy. [see Appendix A]
- Due to the factors noted above, as well as rate increases occurring over past years, the group of large farms <u>is now at an RTC of 98%,</u> even with the declining block rate in place. [See Section 3.3 and Appendix A]
    - There is no reason to expose large farm customers to any increases in their rates for rebalancing purposes. [See Section 4.2]
- The large farms also do not fit well in the Small Industrial class, who now has an average cost to serve that is 12% higher than large farms (an average cost of 15.00 cents/kWh

[4] See Table 10 in Appendix A to this report for calculations

versus 13.35 cents/kWh for large farms). MECL's proposal to include large farms in the Small Industrial class does not provide a solution to the situation faced by large farms. [see Section 3.2]

- The most reasonable outcome at this time is to place the approximately 500 large farm customers into their own class. As a group, they are more than large enough to be a class (over half the size of the Small Industrial class), and there is no other class that has similar annual usage characteristics. [5] [See Section 4]
    - It is also not necessary to prioritize phasing out the first/second block distinction, as the scale of use of energy by this class means that the first block is of trivial importance in rate setting – it serves more like an added fixed charge than any variable price signal.
- As part of the anticipated Stage 2 Rate Design process, MECL should undertake a class re-design of the General Service class (as has recently been done in New Brunswick, and has been proposed for MECL by Mr. Boutillier[6]) based on the results of the General Service load study that is understood to be underway. [See Section 4.2]
- If there becomes a new subclass of the General Service class created that is well matched to the large farm load profile, the new Farm class can be rolled into this class. Otherwise, large farms can remain as their own class. [See Section 4.2]
    - If large farms remain as their own class, internal revenue-neutral rate redesign is likely merited in future, such as to introduce demand rates and potentially restructure second block energy charges. [See Section 4.2]

Additional Recommendations

- There is no basis in Canadian experience, nor in MECL facts, for adoption of the Synapse recommendations to use the "basic customer method" for classification of distribution system costs. Synapse has relied on documentation produced by an advocacy organization to support their conclusions, rather than peer-reviewed or regulator-led balanced literature from such sources as the National Association of Regulatory Utility Commissioners ("NARUC"). MECL, and MECL's Cost Allocation consultants, appropriately rebut the Synapse recommendations in the 2023 Cost Allocation study introduction,[7] and in the MECL Response to Synapse. [8] [See Section 3.3.2]
- Synapse's recommendations to include "cohort 7" customers (particularly cannabis producers and agriculture-related industries) in the large farm grouping does not appear reasonable. Based on the data available, cannabis producers, and particularly agriculture-related industries, are winter-peaking customers who do not share a common load profile

[5] This conclusion echoes Synapse's finding that "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." Ex. C-4, page 28.
[6] Ex. M-1(a), page 7, recommandation 6.
[7] UE21232, Appendix A.
[8] Exhibit M-8

with large farms. These customer groupings should be further investigated as part of the Stage 2 Rate redesign process for General Service customers. [See Section 4.1]

1.2 Summary - Context and Evolution of the Current Application

The Application reflects evidence produced over an extended period, relying on multiple different generations of analyses showing a high degree of evolution in the understanding of MECL's customers and costs, including the latest information filed in late 2024.

However, to understand the context for the decision needed in the current Application, it is important to recognize the evolution and the extent of the Rate Design issues through three phases – (a) pre-2021, (b) 2021 until today, and (c) cost trends into the future.

(a) Pre-2021

In the **period up to 2021**, the Board decisions reflect a confluence of two long-debated issues with respect to MECL rates, the impact of the Residential second-block rate on Residential RTC ratio and the General Service RTC ratio.

- **Residential second block rate:** Starting in 2008 (Order UE08-01), IRAC ordered the gradual elimination of the Residential class second block energy rate which had been in place since 1994. The second block energy rate is a feature of Residential class rates where usage above a certain threshold each month is charged at a different (lower) price than usage up to that threshold. Per UE08-01 (2008), the residential second block rate would have been eliminated by 2010, but the was later delayed in UE10-01 and UE10-03 (both 2010), and UE16-04R (2016).

  As of 2019, the Commission relied on the results of the 2017 Cost Allocation Study to conclude as follows:[9]

  > 357. The Commission recognizes that a change to simply eliminate the residential second block will have a significant impact on farms that are currently within the Residential rate class. However, the reality is that farms, as a class, have been paying significantly less than the cost to serve them for more than twenty years. And for more than twenty years, other ratepayers in this Province have been paying more than their fair share of electricity costs to make up the difference.
  >
  > 358. The subsidization of farms of all size by other ratepayers is not reasonable, publicly justifiable or non-discriminatory. A large industrial farming operation that consumes hundreds of thousands of kilowatt hours per month should not be classified as part of a Residential rate class with a significant declining second block rate. Further, the Commission finds that there is no compelling evidence that the continued subsidization of large farming operations is equitable to all ratepayers.

[9] Order UE19-08, page 49.

This conclusion seems to be one of the main drivers of the current proceeding.

- **General Service RTC ratio:** In combination with concerns over the Residential second block rate reducing the Residential RTC ratio, the 2016 IRAC rate decision (UE16-04R) expressed fairness concerns about the RTC ratios for the General Service class being higher than reasonable:

> [47] … While the RTC ratio for the residential rate classes (excluding seasonal and farm customers) was 92%, the RTC ratio for the general service rate class was in excess of 110%. In simplified terms, the RTC ratios suggest that the general service rate class is subsidizing residential consumers.

These two issues were described as being linked in Order UE20-03:

> 193. As part of the 2016 General Rate Application (Order UE16-04), Maritime Electric was ordered to undertake a rate design study to consider changes to the multi-block residential energy pricing structure (commonly known as the "Residential second block"), and related changes to the Company's other rate structures.
>
> …
>
> 198. The inequities in Maritime Electric's existing rate structure are discussed in detail in Order UE19-08. However, it bears repeating that large farming operations in the Residential rate class are paying less than their cost of service and are being subsidized by other ratepayers. It also bears repeating that General Service customers are paying 22 percent more than their cost of service.

MECL responded to these directives in 2020 with a Rate Design Study by Mr. Boutilier,[10] relying on effectively the same underlying data as available to IRAC during this period, supplemented only by one year of Farm Study data using a year with atypical harvest conditions.[11]

(b) <u>2021 to Today</u>

In the **<u>period from 2021 until today</u>**, the availability and evolution of data has been enormous, and gives rise to significant concerns over the basic analysis and data underlying much of the earlier IRAC conclusions and MECL proposals. This includes the following:

- The MECL Application was prepared with the **2017 Cost Allocation Study** (earlier IRAC decisions had also quoted the 2014 CAS study). These earlier studies did not have recognition of the key size and load distinctions of large farms. As a result, the 2014 and 2017 studies modelled a form of "farm class" using 2,000 farms, most of which were small like residential customers, even though the vast majority of the load was from the 500 large farms. Separately, the 2014 and 2017 studies did not have the benefit of farm load

[10] Exhibit M1(a).
[11] See Exhibit M1, Appendix A, page 7.

profiles, which only started to become available in the later 2020 CAS study. In these earlier 2014 and 2017 studies, the farm RTC ratios were approximately 82%.[12]

- The **2020 Cost Allocation study** became available after MECL prepared the Application. The 2020 study was the first to separate large farms (approximately 500) as the farm class, rather than the 2,000 total of all farms. The 2020 study showed a marked improvement in the farm class RTC (from 87% to 92% depending on the version, as compared to the earlier 82%), reflecting this reduced cohort, and initial improved understanding of the farm class load profile. For example, the farm class Coincident Peak ("CP") load factor increased from 43.7% in 2017 to 66.2% in 2020, reflecting far less peak demand used by farms for each unit of energy consumed than had earlier been assumed (a large increase was also seen for Non-Coincident Peak ("NCP") load factor for farms, from 36.4% to 50.4%). Notionally, this load factor increase was from discovering the largest farm loads (Potato farms) peaking in late October to early December, and drop off notably by late December to February at the time when the rest of the system peaks).[13]
- The **2023 Cost Allocation study** only became available during the preparation of this evidence, after the filing of all Information Requests in this proceeding (see Appendix A to this report for the results using Status Quo approved methods for MECL).[14] The 2023 results reflect a further material shift, with a small revised load profile for farms (CP load factor increases from 66.2% to 74.2%) but a major shift in the load profile for the remainder of the system, driven by residential customers as the largest class (making up approximately one-half of the system energy and two-thirds of the system peak). Due to ongoing increases in heating load, the residential CP load factor decreased from 2020 to 2023 from 48.5% to 39.0% (i.e., the class has a much higher peak now in relation to its energy usage), while the system CP load factor overall decreased from 61.8% to 50.7%. This causes a further major cost shifting, with farms now at 98% RTC. Among the causes is the increased relative use of heating by residences, and the shift of the peak from December (driven more by lighting, a relatively smaller use) to January/February (driven more by heating, now a larger use).

In short, the entire basis of fact underlying MEC's Application has changed. Large farms are not at 82% RTC as was the case when the IRAC directives were first issued – they are at 98% RTC. The impetus for the proposed rate change assumed that farms looked like large residentials in terms of their energy use, but this was not correct. It is increasingly incorrect as residentials adopt more and more electric heating and cause the system peak to increasingly shift with cold weather to January and February, rather than December.[15]

[12] 2014 Cost Allocation Study for MECL, prepared by Chymko Consulting, filed August 9, 2016, page 19, available online: https://www.maritimeelectric.com/media/1097/2014-cost-allocation-study.pdf
[13] Exhibit M1, Appendix A, Farm study, page 11
[14] The 2023 study was prepared by MECL and filed as UE21232 using a small number of unapproved and novel methods (the "Alternative Methods" version). A version that continues the "Status Quo" approved methods has been appended to this evidence as Appendix A, and provided in Excel format. For consistency, this submission consistently uses the results of the Status Quo model.
[15] MECL's 2020 Integrated System Plan, page 28, available online: https://irac.pe.ca/wp-content/uploads/2020-Integrated-System-Plan-filed-September-30-2020.pdf

It remains true in the 2023 study that the Residential class (RTC of 91%) and Lighting (RTC of 66%) must adjust to permit relief for General Service (RTC of 127%). However, if this is done by a simple elimination of the second block rate to all current Residential customers, large farms will see massive increases (approximately 20%) that are not justified on the basis of cost causation.

The alternative solution proposed by MECL – that large farms should be able to migrate to the Small Industrial class – is also not a reasonable solution based on the latest 2023 Cost Allocation study, for three reasons:

- First, the Small Industrial class has a less efficient cost profile than large farms. This can be immediately demonstrated by the fact that Small Industrial average costs (total allocated costs divided by total sales) is 15.00 cents/kWh, but large farms are at 13.35 cents/kWh.[16] The CAS makes clear that farms do not impose a similar cost profile on the system as Small Industrial customers and therefore they do not appear to be homogenous which is the normal basis for combining customers in a class.
- Second, this option is only available assuming a number of requirements can be met with respect to new investment in splitting the service drop from MECL, and adding new metering for the residence versus farm industrial loads, which may not always be possible (and in any event will take time to implement).
- Third, the 2023 CAS specifically notes that the Small Industrial class is poorly represented among load research at this time (its demand loads are only “inferred by subtracting the usage of all other rate classes from total deliveries to the distribution system”[17] which is a highly inferior method for load estimation). As it is a relatively smaller class (compared to Residential, General Service or Large Industrial for example) the movement of a small number of customers can have a substantial impact on load profile, for example one customer moved from small industrial to large industrial and looks to have caused a 13% movement in the class RTC.[18]

For this reason, proposals to allow farms to opt into the Small Industrial class are likely misguided, and in any event they do not provide any form of credible solution for large farms that would otherwise be severely affected by changes to the Residential second block.

It should also be noted that in preparing their evidence, Synapse received the results of the 2020 study, but did not have the results of that study integrated into the MECL application (which relief on the 2017 study). The Synapse report primarily reports data arising from the 2017 CAS. The Synapse report pre-dates the 2023 CAS (including the Status Quo version provided in Appendix A to this submission).

(c) cost trends into the future

On the basis of the ongoing learnings regarding load profiles, the Residential class has a greater responsibility for driving winter peak loads (presumably due to heating) while large farms remain

[16] See Schedule 1.1 Unit Cost Summary, of the 2023 “Status” Cost Allocation Study filed in support of this pre-filed testimony
[17] UE21232 - 2023 Cost Allocation Study, page 24.
[18] As there was no process to ask IRs on the 2023 CAS this can not be exclusively determined at this time.

relatively constrained users of the system at peak times. This learning, and ongoing system evolution, are the main driver of the improvement in large farm RTC ratios from 82% in 2017 to 98% in 2023.

In simple terms, large farms use relatively more energy in relation to peak than most other classes.

Based on the 2024 On-Island Capacity for Security of Supply Application, it is the challenge and cost of reliably meeting the peak at the coldest winter periods that is becoming an increasing driver of investment, and is the most challenging load to service, both from domestic sources and from available imports. This is driving a forecast capacity deficit of 156 MW by 2033 and driving all-time low levels of on-island generating capacity reliance.[19] In contrast, while existing energy supply is suspected to be sufficient in the near-term, energy resources such as wind, solar, and firm and non-firm purchases remain available to meet longer-term need.[20]

It can be difficult to directly infer cost allocation trends into future but based on these investment plans and trends that have been experienced, farm loads are likely to increasingly be lower cost to serve in future as compared to other residential loads. Consider that overall, the average energy-related cost for the entire system as of the 2017 Cost Allocation study was 8.36 cents/kWh[21] while in the 2023 study, the energy-related costs have only increased to 8.41 cents/kWh an increase of only 0.05 cents/kWh, or less than 5% over 6 years.[22] The total average cents/kWh including all of demand, energy and customer-related costs increased by 1.33 cents/kWh during this period, so the demand and customer-related costs (of which large farm customers use far less than typical customers) have been the fastest increasing components of MECL's costs.

Based on these trends and system planning projections, it should be assumed that large farms will see their RTC ratio remain stable or continue to increase further in future Cost Allocation studies, further emphasizing the limited need or rationale for rate rebalancing adjustments to large farms at this time.

The remainder of this submission reviews the above summary of issues in more detail, organized as follows:

- **Section 2 – Basis for Rate Design Change** sets out the detailed background of the IRAC decisions leading to the current Application, as well as relevant information from other MECL regulatory filings.
- **Section 3 – Cost of Serving Farm Customers** sets out a review of the system cost components and results of the various CAS, including the updated 2023 CAS.

[19] As per MECL Request for On-Island Capacity for Security Supply Project, December 18, 2024, available online: https://irac.pe.ca/wp-content/uploads/SCBR-Request-for-the-On-Island-Capacity-for-Security-of-Supply-Project-filed-December-18-2024.pdf
[20] MECL's 2020 Integrated System Plan, pages 29-31, available online: https://irac.pe.ca/wp-content/uploads/2020-Integrated-System-Plan-filed-September-30-2020.pdf
[21] M-1(b) Schedule 1.1, pdf page 36
[22] Appendix A to this submission.

- **Section 4 - Proposed Rate Design Changes for Farm Customers** sets out considerations related to MECL's proposed rate design and rate class changes for Farm customers.
- **Section 5 - Comments on Process and Next Steps** provides high level recommendations on issues to pursue in Stage 2 of MECL's Rate Design process.

2. Basis for Rate Design Change

2.1 Previous IRAC Direction on the Residential Block Rate

The declining block energy rate design for the Residential class has been a longstanding issue. Dating back to 2008, IRAC ordered the full elimination of the declining second block in 2010 (Order UE08-01).[23] However, while the threshold of the first block was increased from 1,200 kWh to 2,000 kWh, the full elimination of the second block was reconsidered by IRAC upon the request of MECL and stakeholders in the 2010 Approval of Rates proceeding, pending further review. MECL noted the circumstances regarding energy negotiations and their potential implications to the overall rate tariff, as well as progress on demand side management programs support the request for reconsideration.[24]

Within this 2010 proceeding, farm groups discussed their limited ability to reduce energy consumption within existing demand side management tools. In addition, current government programs at the time, designed to financially assist farms install on-farm renewable generation, fall short in making a sound business case for the investment. Farm groups suggested that legislation and regulation changes were required by Government to improve the attractiveness of on-farm renewable energy infrastructure.[25]

In the 2016 Approval of Rates Application (UE20942), evidence was brought forward by MECL that Residential customers had an RTC ratio of 92%, and the reduced second block energy charge resulted in a deficit of $773,000 (compared to if the energy usage was charged at the first block energy rate).[26] MECL had initially proposed to gradually increase the threshold of the first energy block for residentials over the course of the 2016 to 2018 test years to 5,000 kWh. However, after negotiations with the Province, this proposal was eliminated. Instead MECL planned to consult with stakeholders to determine the appropriate rate class for all or some farms and file an updated Cost of Service Study. MECL also proposed a cost classification study for its Point Lepreau nuclear generating facility which may have impacts on RTC ratios. At the time, as a base load facility with substantially all costs as fixed long-term and relatively minor fuel costs it was classified as all demand with fuel costs classified as energy.[27]

The Government presented evidence that it was developing a new Provincial Energy Strategy, the results of which could lead to new policy direction on electricity supply and/or usage. The Government also noted that changes to the second block rate could have a significant financial impact on certain consumers. It submitted that consultation should occur with affected consumers prior to implementing any changes and suggested that there may be opportunities to mitigate the financial burden through programs resulting from the Provincial Energy Strategy and DSM.[28]

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[23] Available online: https://irac.pe.ca/Orders/Electric/2008/UE08-01.htm
[24] IRAC Order UE10-03, July 12, 2010, paragraphs 81 & 93, available online: https://irac.pe.ca/wp-content/uploads/UE10-03.htm
[25] Ibid, paragraph 82
[26] IRAC Order UE16-04R, dated July 11, 2016, paragraphs 47 – 49, available online: https://irac.pe.ca/Orders/Electric/2016/UE16-04R.htm
[27] Ibid, paragraph 52
[28] IRAC Order UE16-04R, dated July 11, 2016, paragraph 50, available online: https://irac.pe.ca/Orders/Electric/2016/UE16-04R.htm

IRAC was concerned about the lack of other jurisdictions with declining block rates for residential customers, the rate design encouraging energy consumption, and the Residential class not fully recovering their costs with a 92% RTC.[29] It accepted the proposed deferral of changes to the residential second block pending completion of the Provincial Energy Strategy and the DSM plan. The deferral is intended to allow for consultation with impacted consumers and to explore opportunities to mitigate the financial burden through programs resulting from the Provincial Energy Strategy and DSM.[30]

IRAC noted that:

> *The Commission views the continued existence of the residential second block as being contrary to the principles behind the [Electric Power Act], which directs that the rates, tolls and charges for electric power should be reasonable, publicly justifiable and non-discriminatory… the Commission is hereby putting Maritime Electric and the Government on notice that any proposed continuation of the residential second block rate in future rate applications will require compelling evidence of its equity to ratepayers.*[31]

In the 2018 General Rate Application (GRA) proceeding, MECL delayed filing a rate design study to comply with past IRAC direction, primarily as COVID-19 delayed public consultation. MECL did file its 2017 Cost of Service Application at this time which approximately split out farm-related customer costs from the Residential class, and prior to the culmination of the proceeding, also filed Robert Boutillier's Rate Design Study on June 30, 2020.

In an initial Order of this proceeding UE20944, IRAC specified that:

> *IRAC has previously concluded that Farm customers are receiving an 18% "discount" on electricity costs by having an RTC ratio of 82%, and that this subsidization of large farming operations consuming significant amounts of electricity by other ratepayers is not reasonable, publicly justification or non-discriminatory.*[32]

The Commission recommended MECL consider the viability of alternate rate structures such as Time-Of-Use, demand charges, ascending block rate structures, and the classification of customers based on energy usage rather than application.[33]

In the final IRAC's Order UE20-06 from proceeding UE20944, it noted the following based on the information available to it at the time:

> *The Commission is not prepared to allow the inequities in Maritime Electric's rate structure to continue beyond the current rate setting period. As a result, the Company is required to file with the Commission, and obtain approval for a new rate structure, prior to the filing of its next General Rate Application. The approved*

[29] IRAC Order UE16-04R, dated July 11, 2016, paragraphs 45, 47, 51, available online: https://irac.pe.ca/Orders/Electric/2016/UE16-04R.htm
[30] Ibid, paragraph 57
[31] Ibid, paragraph 59
[32] IRAC Order UE19-08, page 48, available online : http://www.irac.pe.ca/Orders/Electric/2019/UE19-08.pdf
[33] Ibid, page 50.

rate structure will be incorporated into the Company's next General Rate Application so that it can take effect in the next rate setting period.

As explained in Order UE19-08, the Commission deems a revenue-to-cost ratio ("RTC") of 95 to 105 to be the appropriate target range for all rate classes. This does not mean that the RTC for each rate class must be 95 to 105 on March 1, 2022. Instead, the rate structure proposed by Maritime Electric must ensure that the RTC ratios are within the 95 to 105 within a reasonable period of time. The gradual phasing in of the new rate structure is intended to minimize any potential rate shock, and is supported by the expert evidence given by Multeese Consulting and Robert Boutilier.

The Commission emphasizes that the new rate structure to be proposed by Maritime Electric must be comprehensive. It should not focus solely on the elimination of the Residential second block, the treatment of farm customers, or correcting inequities in the revenue-to-cost ("RTC") ratios.

Although these issues must be addressed, the Commission fully expects that Maritime Electric will use this opportunity to present an innovative rate structure that is reflective of the unique mix of customers and classes of customers that the Company serves. The Commission expects that the new rate structure will not only allow the Company to collect revenue in an equitable manner, but will also consider new and innovative rate structures that may provide tangible benefits to its customers.[34]

2.2 Other Relevant MECL Regulatory Matters

In addition to the previous IRAC decisions on rate design, other MECL proceedings and policy documents provide relevant supporting information to properly assess the situation with respect to farm customers.

MECL 2023 GRA

In MECL's 2023 GRA, energy supply costs accounted for approximately 46% of MECL's forecast rate increase.[35] MECL's primary sources for energy generation include:

- Point Lepreau: NB Power provides a detailed forecast of MECL's share of the facilities operating and maintenance costs reflecting planned outage for required maintenance - typically scheduled for spring and lasting from 40 – 100 days.
- Commercial Wind and Solar: There is 92.5 MW under contract with PEIEC and an additional 80 MW of commercial wind and solar expected in service over rate forecast period 2023 – 2025. These are take of pay contracts.

[34] Order UE20944, dated December 21, 2020, Paragraphs 199 – 203, available online : https://irac.pe.ca/wp-content/uploads/Order-UE20-06.pdf

[35] MECL 2023-2025 GRA, page 38-41, available online : https://irac.pe.ca/wp-content/uploads/2023-General-Rate-Application-June-20-2022.pdf

- Remaining energy requirements are purchased through Nova Brunswick Power in three tiers: i) firm energy purchases, ii) secured energy purchases, iii) assured energy purchases.
- MECL also has on-island company owned combustion turbine generation that primarily acts as back up supply during times of curtailment from off-island energy suppliers.

The table reproduced below splits the energy costs by source.[36]

TABLE 5-2
Energy Supply Cost by Source ($000)

Description	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast
Point Lepreau[54]	24,442	23,985	25,758	24,529	25,481	24,661	25,647
Commercial Wind and Solar[55]	24,599	24,958	23,658	24,472	26,635	37,187	50,637
EPA with NBEM:							
Firm Energy	59,046	65,739	73,305	86,057	81,978	77,269	65,475
Secure/Assured Energy	8,725	4,759	6,042	478	124	-	-
Ancillary and Other Services	(3)	207	(606)	-	-	-	-
Company-Owned Generation:							
CTGS	1,440	1,173	802	289	-	-	-
CT3	598	429	650	815	1,164	1,351	1,596
CT1 and CT2	310	313	426	608	607	675	893
Energy Control Centre	952	949	1,000	1,127	1,106	1,154	1,206
Interconnection Costs	4,588	4,602	4,986	4,798	4,605	4,631	4,653
Other NB Power Charges[56]	1,495	1,500	1,504	1,629	1,753	1,761	1,793
Provincial Debt Repayment Cost[57]	-	-	-	-	4,103	5,411	5,457
Other Energy Supply Costs	828	905	1,020	1,228	1,330	1,384	1,441
Total	**127,020**	**129,519**	**138,545**	**146,030**	**148,886**	**155,484**	**158,798**

MECL proposed rate increases in this proceeding by approximately 3.0% for each of fiscal 2023 – 2025 (effective March 1 of each year) to only the energy charge components of customer class rates (i.e. no changes to the demand or customer rate components). Rate increases were not specifically across-the-board for each rate class but close to.[37] The GRA was negotiated with the IRAC approved settlement reducing the rate increase from MECL proposed, still applying to just the energy charge components of each rate on average by 2.6% on March 1, 2023, 2.7% on March 1, 2024 and 2.6% on March 1, 2025.[38]

This follows approved rate increases of approximately 2.9 – 3.0% for the "typical" customer effective January 1, 2022, and a 2.0% rate increase approved effective March 1, 2022.[39] These combined rate increases with the 2023 approved increase are evident in the revenue increases

[36] Ibid, page 40
[37] Ibid, page 100
[38] IRAC Order UE23-04, page 3, avialable online: https://irac.pe.ca/wp-content/uploads/Order-UE23-04.pdf
[39] Approved in IRAC Orders 20-06 and 22-01 respectively.

for each customer class when comparing the 2020 CAS and 2023 CAS, as done Section 3.2 for some classes below.

MECL's 2020 Integrated System Plan (UE21227) & Request for On-Island Capacity Investment (UE20742)

MECL's Integrated System Plan (ISP) was filed with IRAC in 2020. Resource decisions over the next 10-15 years in the Plan were based on the customer forecast reproduced below, which estimates peak winter demand growth slightly outpacing energy growth over the 10 year period.[40] This is a result of expected electrification growth from both space heating and transportation, with the former driving most of the load growth over the past decade, accommodated through spare capacity on the existing system.[41]

Table 1: Energy And System Peak Forecast 2020 – 2030 & Year Over Year Growth Percentage[42]

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
MECL Energy (GWh)	1,443	1,489	1,525	1,560	1,593	1,625	1,656	1,688	1,720	1,752	1,782
Year Over Year Growth %		***3.19%***	***2.42%***	***2.30%***	***2.12%***	***2.01%***	***1.91%***	***1.93%***	***1.90%***	***1.86%***	***1.71%***
Island Energy (GWh)	1,596	1,646	1,687	1,725	1,762	1,798	1,832	1,868	1,903	1,939	1,972
Year Over Year Growth %		*3.13%*	*2.49%*	*2.25%*	*2.14%*	*2.04%*	*1.89%*	*1.97%*	*1.87%*	*1.89%*	*1.70%*
Island Winter Peak (MW)	294	304	312	321	329	337	345	353	361	368	374
Year Over Year Growth %		***3.40%***	***2.63%***	***2.88%***	***2.49%***	***2.43%***	***2.37%***	***2.32%***	***2.27%***	***1.94%***	***1.63%***
Island Summer Peak (MW)	223	226	230	233	237	240	243	247	250	254	257
Year Over Year Growth %		*1.35%*	*1.77%*	*1.30%*	*1.72%*	*1.27%*	*1.25%*	*1.65%*	*1.21%*	*1.60%*	*1.18%*

The resulting growth is driving planned 70 MW of increased wind generation purchases by 2025 (over 2 sites), 50-75 MW of additional Combustion Turbines by 2024 of 'on-island' back up capacity, increased short-term capacity purchases from New Brunswick (from 100 MW in 2019 to 195 MW by 2025 – increasing the dependence on the NB system from 29% to 66%), and a number of transmission project replacements and upgrades.[43]

MECL has since filed a report to IRAC requesting on-island capacity investment to address a forecast capacity shortfall of 156 MW by 2033. The plan consists of a battery storage system, combustion turbine (CT), and reciprocating internal combustion engine plant which will collectively increase on-island dispatchable generating capacity by approximately 50% supporting a more secure power supply for PEI.[44]

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[40] Winter peak growth was projected to increase 27.2% over the time period compared to island energy 10 year growth of 23.6%, page 16, available online: https://irac.pe.ca/wp-content/uploads/2020-Integrated-System-Plan-filed-September-30-2020.pdf
[41] Ibid, page i
[42] Table calculated from Table 5 of as per MECL's 2020 Integrated System Plan, page 16, available online: https://irac.pe.ca/wp-content/uploads/2020-Integrated-System-Plan-filed-September-30-2020.pdf
[43] Summarized from pages 32, 82 & 83 of PEI 2020 ISP, available online: https://irac.pe.ca/wp-content/uploads/2020-Integrated-System-Plan-filed-September-30-2020.pdf
[44] As per MECL Request for On-Island Capacity for Security Supply Project, December 18, 2024, available online: https://irac.pe.ca/wp-content/uploads/SCBR-Request-for-the-On-Island-Capacity-for-Security-of-Supply-Project-filed-December-18-2024.pdf

Energy Efficiency & PEI Energy Strategy

The 10-year PEI Energy Strategy was published in 2016/17 with a commitment to be net zero by 2040. It appears that an Energy Plan to implement and update PEI's strategy for future energy objectives is still in development by PEIEC and efficiency PEI.[45] The new energy strategy is currently in development for release in 2025 will include detailed operational plans and specific actions to implement.[46] It appears the updated plan will continue to prioritize improved efficiency, accelerated electrification and 'on-island' renewable generation, which consists largely of intermittent, non-dispatchable generation sources (wind, solar, etc.).[47]

PEI Energy Corporation's (PEIEC) most recent Energy Efficiency and Conservation Plan for 2022/23 – 2024/25 consists of residential programs focused on efficiency in new home design, home heating and energy efficient technologies (lightbulbs, thermostats, power bars). Commercial and Industrial programming (which includes agricultural operations) adoption has been under-utilized, as a result the program is based on education and enabling strategies to identify which opportunities exist for these customers, including business energy rebates and community energy solutions. Opportunities for agricultural facilities/operations include rebates on high-efficiency products, and up to 50% rebates on energy efficiency upgrades (to $25,000 as of now, however limits are being re-evaluated for agricultural clients).[48] In stakeholder consultations, PEIEC noted that the Federation of Agriculture was engaged to provide a deeper understanding of how to ensure current programming is relevant to the agriculture industry and next steps to be taken to address the needs of the industry over the 2022-2025 period.[49] The Plan makes note of other jurisdictions, such as Maine which offer specifically tailored programs for agricultural customers (such as the Agricultural Fair Assistance Program), but does not offer any specifically tailored solutions for framing/agricultural customers.[50] Lack of access to three phase power has been widely cited by farm customers as a significant barrier to energy conservation.[51] MECL has minimized its involvement in supporting and prioritizing energy efficiency and DSM initiatives to manage system growth and customer opportunities.[52]

[45] As per PEI Energy Strategy website, updated May 3, 2023, available online: https://www.princeedwardisland.ca/en/information/environment-energy-and-climate-action/energy-strategy
[46] As per Government of PEI Energy Blueprint website, updated March 6, 2025, available online: https://www.princeedwardisland.ca/en/information/environment-energy-and-climate-action/pei-energy-blueprint#utm_source=promote&utm_medium=url&utm_campaign=PEIEnergyBlueprint
[47] PEI Energy Blueprint 'What We Heard' Report, published March 6, 2025, pages 8-9 & 12, available online: https://www.princeedwardisland.ca/sites/default/files/publications/pei_energy_strategy_what_we_heard_report.pdf
[48] 2022/23 – 2024/25 EE&C Plan, summarized from sector strategies sections, pages 12-19 & 22-24, available online: https://irac.pe.ca/wp-content/uploads/Exhibit-E-1d-Appendix-A-2022-23-to-2024-25-Electricity-Efficiency-and-Conservation-Plan-and-Appendices-2021.12.20-Final.pdf
[49] Ibid, page 52 of 93
[50] Ibid, pdf page 58 & 59 of 93
[51] Exhibit M-1, pages 7 & Appendix B pages 42 - 48
[52] See for example, MECL's response to Synapse IR-1 in the 2022 Capital Budget Application & ISP proceeding UE21227, pdf page 4, available online: https://irac.pe.ca/wp-content/uploads/A-Resp-to-Interr-from-Synapse-2022-Capital-Budget-and-ISP-filed-Oct-22-2021.pdf

3. Cost of Serving Farm Customers

The costs to serve large farm customers requires proper assessment to inform rate designs, and the degree to which rate rebalancing is required at this time for large farm customers. This includes an understanding of MECL's load and energy cost profiles, as well as the results of routinely updated Cost Allocation Studies.

3.1 MECL's Energy Profile

In 2020, when Mr. Boutillier undertook the Rate Design Study, the load profile of MECL's energy supply was explained as follows:

> Maritime Electric's current energy supply comes from four sources: (i) the Point Lepreau Nuclear Generating Station; (ii) wind produced on Island; (iii) NB Energy Marketing via a long-term energy purchase agreement; and (iv) energy produced by Maritime Electric owned generation under limited circumstances. The unit cost of the first three energy sources is contractually fixed on an annual basis, while the overall energy costs from Maritime Electric-owned generation is generally immaterial on an annual basis. As a result, the Company's current energy supply costs do not vary significantly between peak hours and off-peak hours.[53]

MECL's 2020 ISP load forecast over the 10 year period 2020 – 2030 anticipated winter peak capacity growth of 27% driven primarily from electrification, and forecast energy growth of 23% over the same time period.[54]

Simultaneously, while MECL intends to contract renewable generation in the longer-term to support the PEI Energy Strategy of net-zero by 2040, this type of generation is largely intermittent and non-dispatchable. So while it adds a lot of energy to the system, these generation sources can not be well relied upon to provide electricity at full capacity on demand to meet a system. It requires MECL to invest in capacity-related assets for on-island back up supply, which is expected to be CT generation. Longer-term battery, tidal and nuclear is also being considered as per the 2020 ISP. The result is an increasing price for capacity (i.e. demand-related costs) compared to energy costs. This is exacerbated by customer peak load increasing at a higher rate than customer energy requirements.

This seems to be occurring faster than the 2020 ISP forecast as MECL's electricity peak has exceeded the forecast in recent years, due to strong population and electric heating growth. MECL recently filed the Table below demonstrating a system peak that's been increasing steadily

[53] Exhibit M1(a), page 43
[54] MECL's 2020 Integrated System Plan, page 16, available online: https://irac.pe.ca/wp-content/uploads/2020-Integrated-System-Plan-filed-September-30-2020.pdf
[54] Ibid, page i

since 2021. Recently the 2025 peak happened during a slightly warmer winter than the historical 10-year average, indicating peak growth as a norm, not an anomaly.[55]

TABLE 1 Maritime Electric System Peak Loads			
Year	Temperature at Peak[a] (°C)	Maritime Electric System Peak (MW)	Heating Coefficient (MW/°C)
2016	-15.9	237	2.1
2017	-14.8	250	2.3
2018	-17.1	250	2.5
2019	-13.1	245	2.6
2020	-11.9	260	2.9
2021	-13.3	246	3.1
2022	-18.5	293	3.7
2023	**-23.8[b]**	**359**	**4.1**
2024	-11.0	310	4.5
2025 YTD	**-14.9**	**346**	**5.1**
10-Year Average	-15.4		

a. Source: Environment Canada (Charlottetown Airport).
b. 2023 peak occurred during a polar vortex weather event. The temperature shown is the average temperature for the 24 hours prior to the peak.

This is relevant to Rate Design decisions today, as the rate classes that use electricity coincident to the peak will likely start to see a higher proportion of overall costs shift to them as the overall electricity system continues to change, with MECL investing in capacity to address a forecast capacity shortfall of 156 MW by 2033.[56] Evidence available indicates that Farm customers are not adversely affecting the system peak (discussed more below), which generally occurs on a winter evening across a 4- to 5-hour window, with the highest peak from 5–7 PM. This has increased in recent years from the electrification of space heating.[57] Conversely, sample meter data shows that Farm load typically peaks in the morning.[58]

3.2 Farm Customer Energy Profile

Farm related customers make up approximately 2.6% of MECL revenue collected ($6.2 million of $243.5 million total), and depending on the methods used in cost allocation, at a similar amount of allocated costs.[59]

As continued load research is undertaken on the Farm customer class, refinements continue to be made on the class description, characteristics and assumptions used for cost allocation.

The 2014 Cost Allocation Study was the first undertaken since 2008 and the first to separate out a Farm class from Residential, in preparation for rate design changes that were expected to have disproportionate impacts on farm customers. Chymko undertook the study and assumed the

[55] Exhibit M-3 in Docket UE20472, On-Island Capacity for Security of Supply Project update, filed April 23, 2025
[56] As per MECL Request for On-Island Capacity for Security Supply Project, December 18, 2024, available online: https://irac.pe.ca/wp-content/uploads/SCBR-Request-for-the-On-Island-Capacity-for-Security-of-Supply-Project-filed-December-18-2024.pdf
[57] PEI 2020 ISP, pages 12 & 13 and from Synapse , page 5, available online: https://irac.pe.ca/wp-content/uploads/Final-Report-PEI-Integrated-System-Plan-Alternatives-and-Effect-on-MECL-Capital-Spending-Plans-April-27-2022.pdf
[58] MECL response to Federation of Agriculture Interrogatory IR 22(c), page 14, dated February 14, 2024
[59] 2023 Cost Allocation Study for MECL, prepared by Chymko Consulting, filed October 31, 2024, Appendix B Schedule1.0, pdf page 54 of 126, available online: https://irac.pe.ca/wp-content/uploads/CCL-Cost-Allocation-Study-filed-October-31-2024.pdf

same service line cost and pro-rated peak demand (based on energy sales) as the Residential class.[60] This treatment continued in the 2017 CAS study.[61] The 2020 CAS started to incorporate findings of load research specific to the Farm customer class, finding that Farm customers contribute less to the system peak than the Residential class and resulting in a drop in the farm share of the coincident peak and non-coincident peak.[62]

The 2023 CAS continues to refine Farm load characteristics as load data research continues. Noted by Chymko:

> For the farm group, studies prior to 2020 assumed Farms followed a residential-like behaviour because there was no other information as to how Farms consumed on an hourly basis and Residential and Farm kWh sales trended higher in the winter. Since then, load research is demonstrating that farms consume differently. Though Farm monthly kWh sales are higher during the winter months, hourly usage is more level, meaning that usage is occurring in the off-peak hours, too. This higher load factor means that Farms are not contributing as much to the winter system peaks. On the contrary, Farms' highest peak hours for the year occur in October and November, when the volume of potatoes in storage is highest.[63]

CONCLUSION: *The remainder of the Residential class has evolved to have even more concentrated load at peak times (e.g., through increased heating load), driving a need to recover material costs related to "Coincident Peak" (CP) loads in January/February through their energy rate. This same feature does not apply to large farms given their lesser relative use of coincident peak.*

Simultaneously, refinements have been made over the last decade to the number of customers classified into the Farm rate class. The 2017 CAS included 2,094 year round Farm customers, described as follows:

> While SIC (Standard Industrial Classification) code records are perhaps somewhat inaccurate or incomplete, there are approximately 2,200 MECL residential class customers (large and small) with attached farming SIC codes, with about 2,000-2,100 served year-round. In winter (February for example), about 1,400 of these farms do not require more than first block energy and in summer (July for example) 1,700 do not require more than first block energy. So the majority of farm customers will not be affected by an increase in, or elimination of the second block rate.[64]

[60] 2014 Cost Allocation Study for MECL, prepared by Chymko Consulting, filed August 9, 2016, page 19, available online: https://www.maritimeelectric.com/media/1097/2014-cost-allocation-study.pdf
[61] 2017 CAS, filed June 29, 2018 as proceeding UE21222 as well as in excel format in the 2020 Rate Design proceeding UE22503, Exhibit M3-(a), page 18, available online: http://www.irac.pe.ca/infocentre/documents/Electric-UE21222-2017-Cost_Allocation_Study_Application.pdf
[62] Ibid, pages 19, 20, 26
[63] 2023 Cost Allocation Study for MECL, prepared by Chymko Consulting, filed October 31, 2024, pages 19-20, available online: https://irac.pe.ca/wp-content/uploads/CCL-Cost-Allocation-Study-filed-October-31-2024.pdf
[64] Exhibit M-1(a) MECL Rate Design Study, June 30, 2020, pages 15-16

Of these 2,000+ Farm-related Residential accounts, more than half have no second block usage and would not be impacted by the elimination of the second block energy charge. These would be more akin to a 'family' or 'hobby' farm – with usage much more akin to the Residential class.[65] Others were identified as Residential accounts that were no longer farming.[66]

Starting in the 2020 CAS (and continued in the 2023 CAS), the Farm customer class was refined to include Farm SIC codes with usage above 2,000 kWh/month, reducing the number of sites to 523 (and 517 in 2023). Of these 523 sites, approximately 418 are Farms with usage greater than 5,000 kWh per month.[67] MECL explained this reduction to the Farm class as more accurate for cost allocation purposes:

> The 523 customers identified as 'Farm' customers in the 2020 CAS were specific farm customers. Almost all had greater than 5,000 kWh energy consumption in a given month in 2020, and the remainder were identified through cross referencing known farm operations with customer accounts. These 523 customers are considered the 'large' farms in Maritime Electric's system. The Farm Study undertaken by the Company used a subset (87 in total) of these 523 farms to determine the usage patterns of the Island's large farms and assess the impact on farms of eliminating the declining second block energy charge. It was the information from this subset of large farms that determined the coincident peak ("CP") and non-coincident peak ("NCP") values for the 'Farm' category in the 2020 CAS.[68]

The changes made to the Farm class from ongoing load research and cost allocation impacts are shown in the table below:

[65] Ibid, page 15, and Exhibit M-6, MECL response to Synapse IR-6(d)
[66] Exhibit M-11, MECL response to PEIFA IR-1a(iii)
[67] Exhibit M-3, MECL response to Synapse IR-9b
[68] Exhibit M-6, MECL response to Synapse IR-6d

Table 2: Farm Customer Subclass – Load Characteristics & Cost Allocation Impacts as a Result of Farm specific Load Research[69]

	2014 CAS	2017 CAS	2020 CAS Revised	2023 CAS Status Quo	*2023 CAS Alt. Methods**
Base Revenue ($ Million)	5.832	6.868	5.753	6.224	*6.226*
Allocated Costs ($ Million)	7.173	8.372	6.631	6.343	*6.900*
RTC Ratio	81.3%	82.0%	86.8%	98.1%	*90.2%*
% Share of Rev. Req.	4.00%	4.60%	3.26%	2.61%	*2.84%*
Average Sites/Bills per month	1,987	2,094	523	517	*517*
Energy Sales (MWh)	44,094	52,322	47,023	47,511	*47,511*
Energy Allocator (Input)**	3.80%	4.40%	3.67%	3.20%	*3.20%*
Demand Allocator (1 CP - Input)	4.80%	5.90%	3.40%	2.20%	*3.00%*
Distribution Allocator (NCP - Primary)	4.50%	5.50%	4.30%	3.30%	*3.60%*
Net Rev. Req. Unit Cost (¢/kWh)	16.27	16.00	13.29	13.35	*14.53*
Average Monthly Bill	$ 244.59	$ 273.32	$ 916.67	$ 1,003.22	*$ 1,003.55*
Average Usage per month (MWh)	1.85	2.08	7.49	7.66	*7.66*
NCP Load Factor	41.3%	36.4%	50.4%	48.6%	*48.6%*
CP Load Factor	49.4%	43.7%	66.2%	74.2%	*74.2%*

*2023 CAS Alternative methods include a change to a 3 CP allocator for demand and 3 NCP allocator for distribution
**The Energy Input allocator for 2020 CAS Revised was updated in Exhibit M-11, pdf page 4 - also adjusting allocated costs and the RTC ratio

	2014 CAS	2017 CAS	2020 CAS Revised	2023 CAS Status Quo	*2023 CAS Alt. Methods**
Energy - Input (MWh)	47,351	56,523	50,937	51,488	*51,488*
NCP - Dist. Primary (kW)	13,083	17,749	11,544	12,087	*12,087*
CP - Input (kW)	10,948	14,756	8,780	7,922	*7,922*

As Farm customer energy usage and load characteristics have become better understood through ongoing load research, it is clear that Farm customers are not being subsidized as originally thought in 2014 when this issue was first identified.

At the same time, the result of updated load research reflects higher usage by the Residential class (after removal of Farm customers), due to increased use of electric heat and from strong population growth.[70] The result is an increasing class in both overall energy usage and relative share of system costs, when keeping cost allocation methodology consistent. This is shown in the table below. Comparatively, MECL notes that space heating load associated with farm accounts is not material, with only a small correlation between temperature and electricity usage loads.[71]

[69] Information from Schedules 1.0 – Summary of Cost Allocation Results, Schedule 2.1 – Allocators, and Schedule 2.2 – Allocator Assumptions from each respective CAS. 2023 CAS Status Quo as per Appendix A to this Application.
[70] 2023 Cost Allocation Study for MECL, prepared by Chymko Consulting, filed October 31, 2024, page 19, available online: https://irac.pe.ca/wp-content/uploads/CCL-Cost-Allocation-Study-filed-October-31-2024.pdf & PEI Energy Blueprint, April 20, 2023, page 2, available online : https://www.princeedwardisland.ca/sites/default/files/publications/blueprint_discussion_paper_2023.pdf
[71] MECL response to Federation of Agriculture Interrogatory IR 21, page 9-10, dated February 14, 2024

Table 3: Residential Customer Class – Load Characteristics & Cost Allocation Impacts as a Result of Farm specific Load Research[72]

	2014 CAS	2017 CAS	2020 CAS Revised	2023 CAS Status Quo	*2023 CAS Alt. Methods**
Base Revenue ($ Million)	80.573	83.86	103.055	128.411	*128.201*
Allocated Costs ($ Million)	87.614	91.806	111.034	140.875	*136.907*
RTC Ratio	92.0%	91.3%	92.8%	91.2%	*93.6%*
% Share of Rev. Req.	45.01%	50.28%	54.6%	57.9%	*56.1%*
Average Sites/Bills per month	55,530	57,286	61,785	66,464	*66,464*
Energy Sales (MWh)	480,053	505,169	604,483	727,754	*727,754*
Energy Allocator (Input)	41.20%	42.10%	47.40%	49.60%	*49.60%*
Demand Allocator (1 CP - Input)	52.00%	57.10%	60.30%	64.50%	*60.10%*
Distribution Allocator (NCP - Primary)	49.20%	53.30%	56.00%	61.90%	*60.00%*
Net Rev. Req. Unit Cost (¢/kWh)	18.25	18.17	18.40	19.36	*18.82*
Average Monthly Bill	$ 120.92	$ 121.99	$ 139.00	$ 161.00	*$ 160.74*
Average Usage per month (MWh)	0.72	0.73	0.82	0.91	*0.91*
NCP Load Factor	50.9%	36.4%	49.4%	39.7%	*39.7%*
CP Load Factor	49.4%	43.7%	48.5%	39.0%	*39.0%*

*2023 CAS Alternative methods include a change to a 3 CP allocator for demand and 3 NCP allocator for distribution

Energy - Input (MWh)	515,510	545,726	654,792	789,322	*789,322*
NCP - Dist. Primary (kW)	115,674	171,362	151,306	226,921	*226,921*
CP - Input (kW)	119,190	142,677	153,982	231,276	*231,276*

> ***CONCLUSION:*** *The large farm customers (represented by the Farm subclass in the CAS) have now been monitored by MECL, and it is confirmed that their load profiles are materially different than the remainder of the Residential class. In particular, this is because the customers are larger than average residential customers, and tend to use their highest amount of energy and peak demand at times when the system is less constrained (particularly summer and fall).*

MECL's proposal in this proceeding is provide large farms with the option to move into the Small Industrial class if it proves advantageous to the customer or remain within the Residential rate class. Comparing the load characteristics of the existing Small Industrial class to the Farms subclass, the load characteristics have distinct differences, including that the large farm class is trending more towards efficient load usage (increasing CP factor).

[72] Information from Schedules 1.0 – Summary of Cost Allocation Results, Schedule 2.1 – Allocators, and Schedule 2.2 – Allocator Assumptions from each respective CAS, 2023 CAS Status Quo as per Appendix A to this Application.

Table 4: Small Industrial Customer Class – Load Characteristics & Cost Allocation Impacts as a Result of Farm specific Load Research[73]

	2014 CAS	2017 CAS	2020 CAS Revised	2023 CAS Status Quo	*2023 CAS Alt. Methods**
Base Revenue ($ Million)	11.741	11.675	12.782	13.443	*13.444*
Allocated Costs ($ Million)	12.249	11.402	11.688	13.65	*13.904*
RTC Ratio	95.9%	102.4%	109.4%	98.5%	*96.7%*
% Share of Rev. Req.	6.84%	6.24%	5.71%	5.61%	*5.71%*
Average Sites/Bills per month	268	-	288	285	*285*
Energy Sales (MWh)	88,930	88,162	91,606	90,978	*90,978*
Energy Allocator (Input)	7.70%	7.30%	7.10%	6.20%	*6.20%*
Demand Allocator (1 CP - Input)	6.90%	5.80%	5.20%	6.50%	*7.10%*
Distribution Allocator (NCP - Primary)	11.10%	9.00%	7.30%	6.80%	*7.80%*
Net Rev. Req. Unit Cost (¢/kWh)	13.77	12.93	12.79	15.00	*15.29*
Average Monthly Bill	$ 3,650.81	$ 3,499.70	$ 3,698.50	$ 3,930.70	*$ 3,930.99*
Average Usage per month (MWh)	27.65	26.43	26.51	26.60	*26.60*
NCP Load Factor	34.2%	37.4%	56.8%	39.0%	*39.0%*
CP Load Factor	69.5%	74.5%	84.9%	47.8%	*47.8%*

*2023 CAS Alternative methods include a change to a 3 CP allocator for demand and 3 NCP allocator for distribution.
-2017 CAS does not include average bills/month - as a proxy used average of 2014 and 2020 (278) to calculate avg. monthly bill & avg. usage per month

Energy - Input (MWh)	96,049	95,207	98,430	98,190	*98,190*
NCP - Dist. Primary (kW)	32,095	29,032	19,790	28,761	*28,761*
CP - Input (kW)	15,778	14,593	13,236	23,441	*23,441*

CONCLUSION: *Large farms also do not fit well in the Small Industrial class, who now have an average cost to serve that is 12% higher than large farms (an average cost of 15.00 cents/kWh versus 13.35 cents/kWh for large farms). MECL's proposal to include large farms in the Small Industrial class does not provide a solution to the situation faced by large farms.*

[73] Information from Schedules 1.0 – Summary of Cost Allocation Results, Schedule 2.1 – Allocators, and Schedule 2.2 – Allocator Assumptions from each respective CAS, 2023 CAS Status Quo as per Appendix A to this Application.

3.3 2023 Cost Allocation Study Methodology & RTC Implications

This submission relies on the inputs and analysis of the 2023 CAS filed by MECL in late 2024. This study is further discussed in Appendix A to this submission.

Most notably, the study as filed incorporates a small number of unapproved and novel methods that are not consistent with CAS practice in the province. Most notably, this relates to adoption of coincident peak and non-coincident peak allocation methods, which are new and likely inappropriate for MECL. Regardless, analysis of the present case is appropriate to conduct under Status Quo cost allocation methods, as set out in Appendix A.

3.3.1 Cost Allocation – Coincident Peak Demand Allocator

MECL designs the electricity system with generating capacity planning criteria to meet the forecast customer peak load, less interruptible load, plus a 15% planning reserve.[74] The Transmission and Distribution systems must be designed to a level that can reliably deliver forecast peak load. When assigning system costs, MECL's Cost Allocation Study (CAS) functionalizes all of its Transmission infrastructure and a portion of its Power Supply (Generation) and Distribution Network as demand-related to recognize the role of these assets in ensuring MECL is capable of providing service during the time of system peak.[75]

MECL uses a Coincident Peak (CP) allocator for demand-related costs, which represents each rate class's contribution to the utility's peak demand day. In previous Costs Allocation Studies, MECL used a 1 CP method to allocate these costs, i.e. the single highest actual system peak. New to the 2023 CAS, MECL revised this method and is instead using a 3 CP method to allocate costs to each customer class – i.e. it takes the highest peak from each of the months of December, January and February and averages them.[76] It does not appear that this new method has been tested or approved by IRAC.

MECL rationalizes this method change as historically MECL could reliably depend on the system peak to occur in December but in recent years the system peak has been impacted by weather related incidents that can occur outside 'typical' peak times (albeit still within the winter).[77] However, peak load data recently filed by MECL to IRAC since the 2023 CAS indicates it expects to see weather-driven winter peak growth, such as what occurred in 2023, as the "norm".[78]

As can be shown from the reproduced table below, when comparing the 1CP total system usage (at transmission) of 351,713 kW to the 3 CP total system usage (at transmission) of 303,792 kW – the result is a much more muted allocator, 15.7% reduced. When the purpose is to allocate MECL's system costs that are related to customer demand, the allocator should be as representative as possible to the underlying cost drivers. Also, since MECL's CAS is based on

[74] MECL's 2020 Integrated System Plan, page 17, available online: https://irac.pe.ca/wp-content/uploads/2020-Integrated-System-Plan-filed-September-30-2020.pdf
[75] 2023 Cost Allocation Study for MECL, prepared by Chymko Consulting, filed October 31, 2024, page 14, available online: https://irac.pe.ca/wp-content/uploads/CCL-Cost-Allocation-Study-filed-October-31-2024.pdf
[76] Ibid, page 19
[77] Ibid, page 19
[78] Exhibit M-3 in Docket UE20472, On-Island Capacity for Security of Supply Project update, filed April 23, 2025

actual financial and load results,[79] allocators will not properly account for planning considerations such as customer impact on the reserve margin.

Table 5: Reproduced Portion of Schedule 2.2 from 2023 CAS – Demand-Related CP Allocators[80]

	Residential	Residential (S)	Farm	General Service 1	General Service 1	Small Industrial	Large Industrial	Lights	Unmetered	Total
1CP - Input (kW)	231,276	4,314	7,922	70,414	29	23,441	19,618	1,073	376	358,463
1CP - Input Firm (kW)	231,276	4,314	7,922	69,760	29	23,441	4,584	1,073	376	342,775
1CP - Transmission (kW)	226,921	4,233	7,773	69,088	29	23,000	19,249	1,053	369	351,713
1CP - Distribution Primary (kW)	226,921	4,233	7,773	69,088	29	23,000	4,794	1,053	369	337,258
3CP - Input (kW)	185,944	3,950	9,196	67,948	23	22,069	19,061	1,054	379	309,623
3CP - Input Firm (kW)	185,944	3,950	9,196	67,349	23	22,069	4,645	1,054	379	294,608
3CP - Transmission (kW)	182,443	3,875	9,023	66,668	22	21,653	18,702	1,034	372	303,792
3CP - Distribution Primary (kW)	182,443	3,875	9,023	66,668	22	21,653	5,210	1,034	372	290,300

This issue was recently considered in the New Brunswick Power Class Cost Allocation Study Methodology Review (Matter #0554), where the New Brunswick Energy & Utilities Board directed NB Power to develop a proposal to modify its CP allocator away from the 3 CP method to be replaced by a single forecast peak value or highest 10 historical peak hours (the top 10 historic peaks are not bound by rules of specific months, etc. and were chosen as a potential alternative as this amount represented an approximate 7.5% variation from the single peak). It specifically justified this because the values used in the 3 CP allocator did not fall within 10% of the single coincident peak,[81] a recognized approach in the NARUC Manual on Cost Allocation which specifies that if using more than one CP determining the hours to include should pass established threshold value.[82] As the MECL recommended method change results in a overall system peak decrease of over 15.7%, it falls outside of the 10% band recommended in the NARUC Manual.

The unapproved methodology change filed by MECL in the 2023 CAS is negatively impacting farming customer RTCs while simultaneously muting the demand-related system cost drivers.

3.3.2 Synapse Recommendation for Distribution "Basic Customer Method"

Synapse also provides an additional recommendation for redesign of the Residential class monthly customer charge. In support of this recommendation, Synapse recommends MECL adopt a revised method for classifying distribution-related costs using what is termed the "basic customer method".

MECL provides an appropriate and entirely accurate rebuttal to this recommendation in their response to Synapse.[83]

It is also appropriate to note that Synapse relies on only one document to justify their proposal – a reference entitled "Electric Cost Allocation for a New Era" produced by the environmental non-profit the "Regulatory Assistance Project" (or "RAP"). The manual sets out advocacy for specific provisions and methods, reflecting those typically adopted by representatives for small customers

[79] Ibid, page 1 the 2023 CAS is based on financial results for twelve months ending December 31, 2023
[80] 2023 Cost Allocation Study for MECL, prepared by Chymko Consulting, filed October 31, 2024, Appendix B, pdf page 73 of 126, available online: https://irac.pe.ca/wp-content/uploads/CCL-Cost-Allocation-Study-filed-October-31-2024.pdf
[81] NBEUB Decision in Matter #0554, April 2, 2025, pages 13 and 14, available online: https://nbeub.ca/uploads/2025%2004%2002%20-%20Matter%20554%20-%20Reasons%20for%20Decision.pdf
[82] National Association of Regulatory Utility Commissioners, Electricity Utility Cost Allocation Manual, January 1992, pages 46 & 47
[83] Exhibit M-8.

or environmental advocates. Competing advocacy has also been produced by experts in the cost allocation field, as a "rebuttal" of the RAP, which was not referenced by Synapse[84].

In contrast to the Synapse reliance on advocacy literature, MECL has elected to focus their literature review on guidance from the National Association of Regulatory Utility Commissioners ("NARUC"), professional regulators and regulatory staff who must balance multiple interests including both those typical of the RAP perspectives, as well as other customer types. The NARUC manual has been accepted as an authoritative work, and is an appropriate source for descriptions of accepted and reasonable cost allocation methods, as a starting point for determining an appropriate CAS methodology for each specific jurisdiction.

> ***CONCLUSION:*** *There is no basis in Canadian experience, nor in MECL facts, for adoption of the Synapse recommendations to use the "basic customer method" for classification of distribution system costs. Synapse has relied on documentation produced by an advocacy organization to support their conclusions, rather than peer-reviewed or regulator-led balanced literature from such sources as the National Association of Regulatory Utility Commissioners ("NARUC"). MECL, and MECL's Cost Allocation consultants, appropriately rebut the Synapse recommendations in the 2023 Cost Allocation study introduction,[85] and in the MECL Response to Synapse.* [86]

[84] For example, see "Rebuttal of the Key Recommendations in the Regulatory Assistance Project's Electric Cost Allocation Manual, by Brubaker and Associates Inc., available as Attachment 1 to this link: https://www.michigan.gov/-/media/Project/Websites/mpsc/workgroups/der/U-20960_--_Comments_of_ABATE_92221.pdf?rev=863ad46685d64a6c99e2276cc7508f39

[85] UE21232, Appendix A.

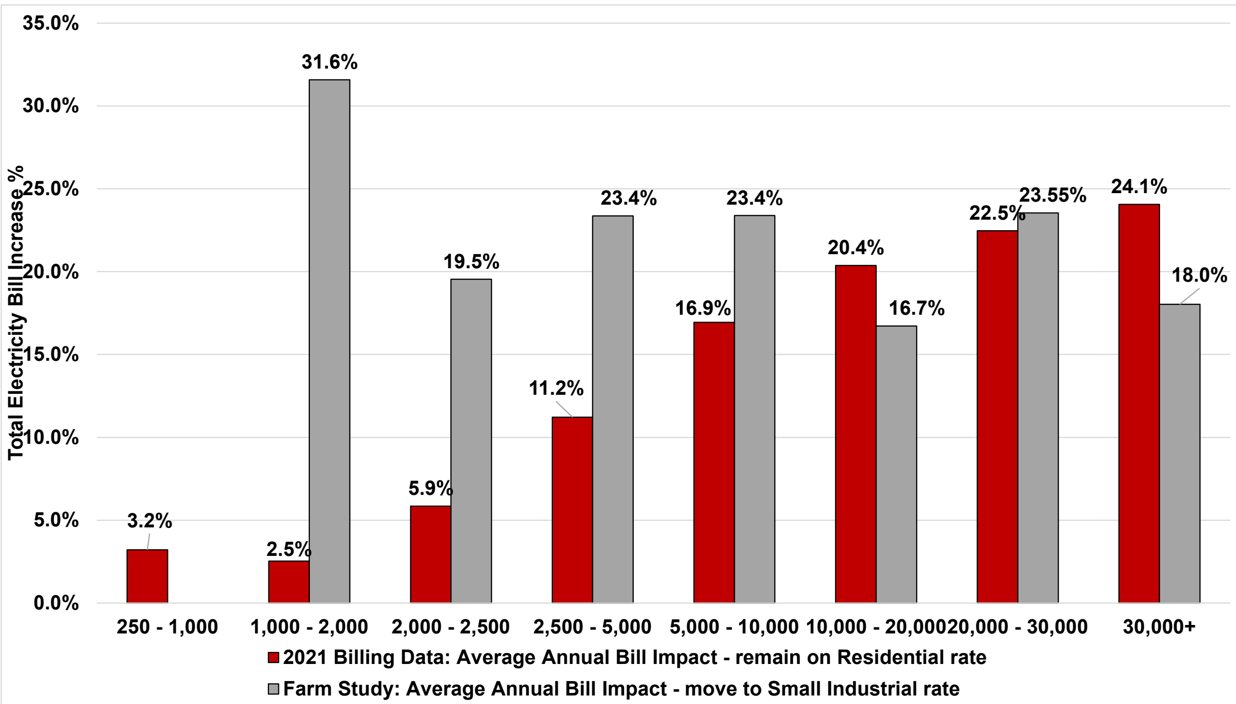
[86] Exhibit M-8

4. Impacts on Farm Customers

MECL is proposing that Farm customers either remain in the Residential rate class, post removal of the second block energy charge, or be offered the choice to move into the Small Industrial rate class if eligible.

For the majority of Farm customers, especially those with moderate to higher usage (at least one month exceeding 2,000 kW.h per month), both options result in large rate impacts compared to current electricity bills, as shown in the Figure and Table below.

Figure 1: Annual Electricity Bill Impact Comparison for MECL's Rate Proposal - Farm Customers with over 2,000 kWh/month Usage (Grouped by Avg. Monthly Usage in kWh)[87]



Note that in the above table, the horizontal axis is the average monthly usage. There are customers that have average monthly usage in the 250 - 1,000 kWh range, or the 1,000 - 2,000 kWh range, who nevertheless occasionally use the second block (i.e., have a month where energy usage exceeds 2,000 kWh) which is the reason they exhibit a rate impact from the MECL proposal.

The customers represented above can be loosely grouped into two categories – those that average below 2,000 kWh per month (370 customers) and those that average higher (528 customers). The usage bands can be further subdivided to portray bill impacts, as shown in Table 6. Note that only customers who were included in the Farm Study can have bills estimated were

[87] 2021 Billing Data as per Exhibit M-11a Attachment 1, 'Farms' tab, uses monthly customer usage to calculate bill impacts based on rates in effect as of June 2025 (17.23 ¢/kWh for first block and 13.75 ¢/kWh for second block energy against 17.23 ¢/kWh for all energy). Move to industrial rate impacts as per customer level farm study data provided in Exhibit M-3k Synapse IR-26 'Chart data' tab.

they to move to the Small Industrial rate, as the others have unknown demand consumption, which is a necessary factor to calculate the bill under the Small Industrial rate.

Table 6: Rate Impact Comparison Table for Farms who have at least one month above 2,000 kWh usage[88]

Annual Usage (kWh)	Average Monthly Usage (kWh)	# of Farm Customers	2021 Billing Data: Average Annual Bill Impact - remain on Residential rate	# of Customers in Farm Study	Farm Study: Average Annual Bill Impact - move to Small Industrial rate
3,000 - 12,000	250 - 1,000	69	3.2%	0	-
12,000 - 24,000	1,000 - 2,000	301	2.5%	1	31.6%
24,000 - 30,000	2,000 - 2,500	92	5.9%	5	19.5%
30,000 - 60,000	2,500 - 5,000	213	11.2%	11	23.4%
60,000 - 120,000	5,000 - 10,000	154	16.9%	27	23.4%
120,000 - 240,000	10,000 - 20,000	51	20.4%	32	16.7%
240,000 - 360,000	20,000 - 30,000	10	22.5%	6	23.55%
360,000+	30,000+	8	24.1%	5	18.0%
Total		**898**		**87**	

Compared to the 2020 CAS, which included 523 sites in the Farm class, Farm customers using on average 2,000 kWh/month or more from the 2021 data set is equal to 528 accounts. From the 2021 data set, customers have the following distribution between first and second block energy usage:

[88] 2021 Billing Data as per Exhibit M-11a Attachment 1, ‘Farms’ tab, uses monthly customer usage to calculate bill impacts based on rates in effect as of June 2025 (17.23 ¢/kWh for first block and 13.75 ¢/kWh for second block energy against 17.23 ¢/kWh for all energy). Move to industrial rate impacts as per customer level farm study data provided in Exhibit M-3k Synapse IR-26 ‘Chart data’ tab. For Farm Study tab, impact from small industrial rate was grouped into annual usage in line with customer premise number 2021 data where applicable (there were 17 accounts in the Farm Study information that did not correspond to Farm accounts for the 2021 billing data provided, these were instead grouped by annual usage as per the amounts provided in Exhibit M-3k).

Table 7: Farm Customer Usage between First and Second Block for Farms who have at least one month above 2,000 kWh usage[89]

Annual Usage (kWh)	Average Monthly Usage (kWh)	# of Farm Customers	Average First Block Energy Usage (% of Total Energy)	Average Second Block Energy Usage (% of Total Energy)
3,000 - 12,000	250 - 1,000	69	82.7%	17.3%
12,000 - 24,000	1,000 - 2,000	301	86.6%	13.4%
24,000 - 30,000	2,000 - 2,500	92	71.0%	29.0%
30,000 - 60,000	2,500 - 5,000	213	46.7%	53.3%
60,000 - 120,000	5,000 - 10,000	154	25.8%	74.2%
120,000 - 240,000	10,000 - 20,000	51	14.9%	85.1%
240,000 - 360,000	20,000 - 30,000	10	8.4%	91.6%
360,000+	30,000+	8	2.2%	97.8%
Total		**898**	**32.0%**	**68.0%**

The impact to customers from dropping the second block declining rate is linear and increases with annual usage (as the proportion of second block energy increases with higher annual usage as shown in the table above).

However, the impact of switching from the current rate structure to the Small Industrial rate is not uniform by usage level; i) because customers of varying energy levels will all have different billing demand and load factors, which will vary the individual impacts of switching to the small industrial which includes a demand charge, and ii) likely also a result of a smaller sample size with only 10% of total Farm customers from the 2021 billing data appearing in the Farm Study and therefore represented in the Move to Small Industrial bill impact table above. As a result, MECL's proposed solution for Farms to either remain on a Residential rate with flat energy charge or move to the Small Industrial rate would be a determination each customer would have to make individually, however the Small Industrial rate appears to be the better option, on average, above 100,000 kWh annual usage. Compared to the current rate structure however, no Farm Study customer is better off on the Small industrial rate.[90]

This adverse and unnecessary outcome to large farms is avoided with the creation of a Farm customer class for those approximately 500 customers who average above 2,000 kWh per year. This solution has been recommended or acknowledged as a reasonable alternative by all involved in this process to date.

- Robert Boutillier in the 2020 Farm Study suggested that moving them into their own class as a valid option that may closely match the cost of service and recognizes and addresses

[89] 2021 Billing Data as per Exhibit M-11a Attachment 1, 'Farms' tab, uses monthly customer usage, summing usage up to 2,000 kWh/month to calculate percentage of first block usage of total energy for each customer.

[90] As per Exhibit M-3k 'Chart Data' tab, customer impacts of the 87 customers included ranged from 0.1% to 52.7% rate increase as a result of switching from the current Residential declining block rate structure to the Small Industrial rate.

cost causation differences from the Residential class. Mr. Boutillier ultimately recommended MECL's proposal to remove the second block rate and then provide the option for farms to stay within Residential or switch to the Small Industrial rate to address the revenue shortfalls reported in the information before him at the time, as his report reviews one year of farm load research and the 2017 CAS.[91]

- Synapse's report findings acknowledge merit to the proposition that farms be separated into a new rate class on the basis of 2017 and 2020 data it reviewed at the time of its 2022 report.[92] Synapse notes that, "[o]ur 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."[93] However, Synapse was concerned that the farm load was not substantial enough to justify a class. It is worth noting that the large farm load is more than 10 times the size of the Lighting class, and larger than either the Residential Seasonal class or the General Service seasonal class.
- MECL indicated it was not convinced that a separate Farm rate was warranted,[94] based on MECL's conclusion regarding the comparability of the potential farm rate to the Small Industrial rate. However, this determination was based on the 2017 and 2020 CAS results. As discussed in Section 3 above and set out in detail in the Appendix A 2023 CAS model, these customer groups in fact have distinct and diverging load and cost characteristics (Small Industrial more than 12% more costly to serve on a unit basis, than large farms).[95]

RECOMMENDATION: *The most reasonable outcome at this time is to place the approximately 500 large farm customers into their own class. As a group, they are more than large enough to be a class (over half the size of the Small Industrial class), and there is no other class that has similar annual usage characteristics.*

- *It is also not necessary to prioritize phasing out the first/second block distinction, as the scale of use of energy by this class means that the first block is of trivial importance in rate setting – it serves more like an added fixed charge than any variable price signal.*

4.1 Customer Eligibility for the Farm Rate Class

In developing a distinct Farm rate class, it is necessary to clarify which customers fall within the class. In general, the CAS grouping of all specifically identified Farm customer SIC codes with average usage above 2,000 kWh (i.e., about 500 customers). Below the 2,000 kWh/month, it would not be anticipated that farm loads would be homogenous with the large farms. Further, future rate redesign for the Farm class may introduce a demand charge component, which would be inconsistent with smaller Farm users whose load profile is closer to Residential in nature.[96]

[91] Exhibit M-1(a), page 16 & 63
[92] Exhibit C-4, Synapse report, page 19-20
[93] Exhibit. C-4, page 28.
[94] MECL response to Federation of Agriculture Interrogatory IR-25(i), page 30, dated February 14, 2024
[95] MECL response to Federation of Agriculture Interrogatory IR-22(k), page 17, dated February 14, 2024
[96] As referenced by MECL in response to Federation of Agriculture Interrogatory IR-22(l), page 18, dated February 14, 2024

Customers with distinctly different electricity uses and load characteristics from Farm customers should remain separate from a Farm class. In some of the analysis in this proceeding, MECL has grouped 45 Residential customers together in an "Other" category as they are not farms but on average use above 5,000 kWh/month (also known as "Cohort 7" in the Synapse report). Cohort 7 customers consist of churches, premises providing lodging (with nine beds or less), and dwelling/business combinations and are currently eligible for the residential rate based on MECL's Residential Service Guidelines.

Synapse recommends that cannabis operations (2 customers), fish farms (3 customers), and agricultural-related operations (19 customers) are mischaracterized and should be categorized with other large farms ("cohort 6") based on the MECL's Schedule of Rates and General Rules and Regulations definition of 'farm'.[97] Customers in the remaining "cohort 7" categories (religious organizations, government housing, misc. commercial) are all comparatively smaller monthly users and there seems to be no recommendation to remove these customers from the Residential rate class.[98]

Focusing on Synapse recommendation for cannabis operations, fish farms and agricultural-related operations specifically, movement of these customers into the new Farm class is not recommended at this time (with the possible exception of fish farms):

1) Cannabis Operations

There are two cannabis operations that each use on average approximately 500,000 kWh/month.[99] This amount of energy usage far exceeds all existing individual Farm customer usage. Adding 11 million kWh of energy/year into the new Farm class would distort the entire class usage by almost 25% from only 2 customers.[100] These customers also do not exhibit an annual usage profile that is consistent with large farms. Given their size, these customers require individualized consideration from MECL, as part of the Stage 2 General Service rate redesign process.

2) Agriculture-Related Operations

There are nine customers included in 'Agriculture-related operations' that have annual energy usage for the year 2021 that varies significantly, as shown in Table 8:

[97] Exhibit C-4, Synapse report, page 18

[98] The Rate Study undertaken by Robert Boutillier did not make a recommendation with respect to these customers. MECL states that they are committed to working with these customers to evaluate the options available to them for service and ensure they are appropriately classified, however does not provide any proposals other than to include them in the Residential class elimination of second block energy rate then allow eligibility into the Small Industrial rate class thereafter. Exhibit M-3, response to Synapse IR-28

[99] Exhibit M-7a, response to Synapse IR-2, Attachment 1

[100] Energy sales from Schedule 2.2 of the 2023 CAS for the Farm class was 47,511 MWh.

Table 8: 2021 Monthly Energy Usage Swings (kWh)[101]

Agricultural-related operations:		2021 Annual Usage (kWh)	2021 Monthly Max Energy (kWh)	2021 Monthly Min Energy (kWh)	2021 Spread	*Monthly Energy Usage Percentage Range*
Customer	1	113,160	22,080	840	21,240	*96.2%*
Customer	2	62,720	16,520	1,560	14,960	*90.6%*
Customer	3	24,360	12,540	-	12,540	*100.0%*
Customer	4	1,741,080	310,320	36,840	273,480	*88.1%*
Customer	5	67,120	8,960	2,320	6,640	*74.1%*
Customer	6	48,217	5,699	2,486	3,213	*56.4%*
Customer	7	59,501	9,130	3,400	5,730	*62.8%*
Customer	8	24,401	3,513	1,097	2,416	*68.8%*
Customer	9	155,360	17,360	7,520	9,840	*56.7%*
Total		**2,295,919**				

While no peak (hourly) data was provided for these customers, Customers 1- 4 in particular have substantial variability in their monthly energy usage, which is far outside the norm of the typical large farm customer. Specifically for Customer 4, there are only two other Farm customers with monthly usage in the range of 300,000 kWh/month, and both of these customers use energy far more consistently month-over-month.

Consequently, the information available raises concerns regarding the rate class for these customers (customers 1 – 4, but particularly customer 4) given the high magnitude of annual energy purchases compared to the typical Residential class customer (and large farm customer).

In general, without evidence regarding the individual energy consumption patterns which would indicate if these customers are homogenous with the new Farm class customers, they should not be included in the Farm customer category at this time. Further consideration as part of the Stage 2 General Service rate redesign is merited.

3) Fish farms

There are three customers in the ‘fish farm’ category of cohort 7. The average customer use is 50,000 kWh/month.[102] This usage level would put fish farm customers in the range of the top 5 Farm customer usage.[103] On aggregate, however, these customers appear to use energy on a more consistent monthly basis (i.e., do not exhibit peaks tied to weather or heating). Although hourly peak data was not provided to assess homogeneity, it is possible that MECL may provide the opportunity for these customers to be included in the new Farm class.

> ***CONCLUSION**: Synapse’s recommendations to include “cohort 7” customers (particularly cannabis producers and agriculture-related industries) in the large farm grouping does not appear reasonable. Based on the data available, cannabis producers, and particularly agriculture-related industries, are winter-peaking customers who do not share a common*

[101] Exhibit M-7a, response to Synapse IR-2, Attachment 2
[102] Exhibit M-7a, response to Synapse IR-2, Attachment 1
[103] Exhibit M-11(a), IR-1 Attachment, ‘Farms’ tab

load profile with large farms. These customer groupings should be further investigated as part of the Stage 2 Rate redesign process for General Service customers.

4.2 Declining Block Farm Class Rate Structure

While IRAC has previously expressed concern that the declining block rate structure currently in place for Residential and Farm customers encourages energy consumption,[104] this is not necessarily the case for large farms. In the case of most large farms, every kW.h in the first block will be used every month such that the only price signal that the customer experiences is the second block price. Based on the 98% RTC ratio, this price signal to large Farms is fulfilling all appropriate consumption signalling.

It is also worth noting that the General Service rate class also has a declining block energy rates in place.[105]

Additionally, there is Canadian precedent for a Farm-specific rate, which can include declining block structures. Saskatchewan also has a strong agricultural sector, and SaskPower offers a Farm specific rate with a declining second block energy charge. SaskPower additionally offers an irrigation rate for farm loads served between April 1 and October 31, effectively a surplus energy rate during the non-peak months.[106] Other utilities including Fortis Alberta and BC Hydro have rates in place for qualifying Farm customers as well.[107]

As the new Farm class is in a similar position of Small Industrial with an RTC ratio within the zone of reasonableness, even with the declining block rate in place, there is no reason to expose this group of customers to any increases in their rates for rebalancing purposes. Reverting the second block rate to the pricing for the first block rate as a result of this proceeding would result in an RTC ratio of 114% per Appendix A – effectively driving the large farm customer outside the zone of reasonableness, directly contrary to the original policy intent.

CONCLUSION: *There is no reason to expose large farm customers to any increases in their rates for rebalancing purposes.*

As part of the Stage 2 General Service rebalancing/segmentation, MECL may consider if the farm class remains necessary or whether a potential new General Service subclass may permit fair and reasonable farm rates. Similar review was recently undertaken by New Brunswick Power, where the General Service class was reclassified and segmented for distribution-connected customers based on size (based on maximum billing demand), and a Large Industrial class was created for transmission-connected customers. No party involved opposed the class reclassification and the Board approved it, concluding it would reduce inequity within the rate structure.[108]

[104] For example, in Order UE16-04 of proceeding UE20942, dated July 11, 2016, paragraph 45, available online: https://irac.pe.ca/Orders/Electric/2016/UE16-04R.htm

[105] Rates in place for MECL as of June 25, 2025, available online: https://www.maritimeelectric.com/about-us/regulatory/rates-and-general-rules-and-regulations/

[106] SaskPower's farm rate, effective April 1, 2025, available online: https://www.saskpower.com/-/media/saskpower/accounts-and-services/rates/service-rates/power-supply-rates/servicerates-farm.pdf

[107] BC Hydro provides an Irrigation rate for non-peak months March – October, as explained online: https://app.bchydro.com/accounts-billing/rates-energy-use/electricity-rates/irrigation-rate.html . Fortis Alberta offers Farm Service Rate 22, which provides distribution and transmission services to qualifying farm customers, available online: https://www.fortisalberta.com/docs/default-source/default-document-library/april-1-2025-fortisalberta-rates-options-and-riders-schedules.pdf?sfvrsn=d7b6981b_6

[108] See New Brunswick Energy & Utilities Board Reasons For Decision in the New Brunswick Power Rate Design Application, Matter #0529, dated October 27, 2023 pages 8 – 13, available online: https://nbeub.ca/uploads/2023%2010%2027%20-%20Matter%20529%20Reasons%20for%20Decision.pdf

If the Farm class remains on its own, MECL may want to propose a Farm class rate redesign such as to introduce demand charges and reduce energy charges, but this is an issue for the Stage 2 portion of the process, at the earliest (appropriate demand data would need to be collected on all farm customers to permit this type of rebalancing).

> ***RECOMMENDATION:*** *As part of the anticipated Stage 2 Rate Design process, MECL should undertake a class re-design of the General Service class (as has recently been done in New Brunswick, and has been proposed for MECL by Mr. Boutillier[109]) based on the results of the General Service load study that is understood to be underway.*

> ***RECOMMENDATION:*** *If there becomes a new subclass of the General Service class created that is well matched to the large farm load profile, the new Farm class can be rolled into this class. Otherwise, large farms can remain as their own class.*

> - *If large farms remain as their own class, internal revenue-neutral rate redesign is likely merited in future, such as to introduce demand rates and potentially restructure second block energy charges.*

[109] Ex. M-1(a), page 7, recommandation 6.

5. Comments on Process and Next Steps

It is understood that MECL intends to undertake a “Stage 2” to the rate design process to address more detailed matters once this process (Stage 1) concludes.

Building on the creation of a new Farm class in Stage 1 for large farm customers averaging above 2,000 kWh monthly energy usage, there are additional areas of review that would be appropriate to include in Stage 2, including:

- **Further Rate Rebalancing:** MECL proposes to address any remaining class revenue rebalancing for classes that will be outside of the RTC ratios, such as General Service and Residential classes, in a second stage of its Rate Design Application, post-March 1, 2025.[110]
    - It is not clear when MECL intends to initiate Stage 2 at this time given the substantial amount of time that has elapsed since the filing of Stage 1 in 2021. It may be important to include in this step proposals for any intra-class rate rebalancing to address policy considerations such as ‘energy consumption signalling’ and/or the Provincial Energy Strategy.
- **Cost of Service methodology changes**: MECL has modelled the 2023 CAS using consequential methodology changes. It does not appear MECL has sought approval for these changes. Cost of Service methods are highly linked to fairness considerations, and to rate design decisions, as they impact customer RTC ratios. Any changes to CAS methodology should be done as part of a fulsome regulatory process reviewing Cost Allocation Study methodology as a whole, based on principled rationale that supports cost causation, system use and system planning.
    - Any rate design changes should only be developed and proposed using Status Quo approved CAS methodology.
- **Continued Interval Meter Load Data Collection:** In the 2020 Farm Study, Mr. Boutillier recommended that the interval metering projects already underway by MECL relating to farm load, as well as more detail regarding Residential and General Service customers should continue, with the data archived and analyzed. Mr. Boutillier noted that the information would be useful for future cost causation and rate analysis. MECL has noted it continues to collect interval metering data.[111]
    - As it has now been 5+ years that MECL has been collecting data on Farms, Residential and General Service, and Small Industrial there should be substantial load data to analyze ahead of Stage 2 regarding rate design and load characteristics. A report that highlights findings on customer load characteristics for rate classes would be helpful to understanding rate design opportunities for Stage 2 of the review.

[110] Exhibit M-1, page 8
[111] Exhibit M-1(a), Farm Study, page 4, pdf page 61 of 152 & Exhibit M-1, page 16

- As new customer meters have been installed that can provide monthly demand and energy readings, that data should be added to the load research being undertaken.[112] It is understood that MECL has an ongoing to Advanced Metering Infrastructure (AMI) installation program in place that would facilitate this data collection.[113]

[112] As noted in MECL response to Federation of Agriculture Interrogatory IR-20(a), page 1, dated February 14, 2024, MECL continued to install meters since the original data set was collected.
[113] MECL response to Federation of Agriculture Interrogatory IR-25(j), page 31, dated February 14, 2024

Appendix A:

2023 Cost Allocation Study – Status Quo Methods

Appendix A – 2023 Cost Allocation Study – Status Quo Methods

On October 31, 2024, after all other information available for this proceeding had been filed, MECL produced a version of the Cost Allocation Study for 2023. This was filed with IRAC as UE21232.

The study was produced only in pdf form, without Excel versions.

The study indicates continued evolution in the PEI electrical loads in terms of both coincident peak ("CP") and non-coincident peak ("NCP") loads, particularly the following:

- Large farms have flatter annual loads and peak at times that are less coincident with the rest of the system than in past studies. This reduces costs allocated to the Farm class.
- Residential customers have increased coincident and non-coincident peaking needs in relation to their energy usage, indicated to relate to increased electric heating. This increases costs allocated to the Residential class, and reduces costs allocated to the other classes.
- Small industrial has seen a major change in load factor, which apparently tied to the reduction of one very large customer. This has increased the costs allocated to Small Industrial (reducing their RTC ratio).

Unfortunately, the study produced by MECL incorporates three novel or unapproved methods that result in the filed version being incompatible with past studies. These are as follows (the "Alternative Methods"):

- **Coincident Peaks:** The approved cost of service methods for MECL are the use of a single Coincident Peak allocator ("1CP for generation and transmission demand-related costs. Instead, the 2023 study adopts a new method based on a 3 Coincident Peak ("3CP") allocator. This is a significant change in the model methods that has not been approved by IRAC, and that does not accord with the ongoing evolution of the system which is driven increasingly by heating-load driven peaks. In fact, 3CP allocators serve to mute the very price signals needed to reflect the classes that are driving increasing system investment to serve the highest peak loads (plus reserves for unanticipated worse-than-expected conditions, including weather).[114]
    - Similar to the move to 1CP, MECL has also included a change to use 3 Non-Coincident Peaks ("3NCP") for allocating distribution demand costs, and not the approved 1 NCP method.
- **Charlottetown Thermal:** The Charlottetown Thermal Generation Station ("CTGS") capital investment has traditionally been classified as a 100% demand-related resource, which has been retired. MECL has created a new account 9,412 to address amortization of a residual CTGS Capital Reserve Variance but incorrectly classified the cost as not being linked to capacity.
- **Maritime Interconnection Facilities:** Accounts in the 7,400 range are related to Maritime Interconnection Facilities. Account 7,400 records a loan payment for "Cable Interconnection". Though it makes little difference to the end RTC results (approx. 1%), the study appears to incorrectly list the costs as "Generation" with no capacity classification. If cable linked, the costs should be Transmission. If the costs are instead related to generation facilities outside the province (e.g., Lepreau) then it should be

[114] Note that New Brunswick has traditionally used a 3CP allocator, but recent regulator decisions indicate a need to move away from the 3CP allocator as electric heating loads increasingly drive peaks, per Matter 554.

functionalized as Generation, but with a 25% capacity classification, consistent with the other Lepreau assets.

Despite the lack of an Excel model for 2023, MECL has made available the 2020 version of the model in Excel form (Exhibit M-3(b)) which permitted an update to be produced to bring the data up to 2023 inputs. Using this 2023 version, it is possible to correct the above input issues to generate RTC ratios that can be compared to the 2017 and 2020 versions on a Status Quo basis. The updated model for 2023 is attached in both pdf and Excel form.

The key finding is that the most significant methodology change put forward by MECL relates to the adoption of a 3CP demand allocator for generation and transmission costs (as well as a 3 NCP allocator for distribution costs). More than 90% of the change from the Alternative Methods model produced by MECL to the Status Quo Methods model is from the unapproved change to use a 3CP allocator. In the MECL Alternative Methods model, farm RTC is 90%, while the change to the approved 1CP method changes the large farms RTC to 97%. Reversing the other two changes submitted by MECL combined moves the RTC for large farms to 98%, as reported in the attached model output.

The results of the Status Quo 2023 study as compared to the final 2020 study are as follows:

Table 9: MECL Revenue to Cost Ratio

	2020	2023 Status Quo Methods	*change*	*2023 Alternative Methods*
Residential	93%	91%	*(2%)*	*94%*
Residential (S)	94%	89%	*(5%)*	*88%*
Farm	87%	98%	*11%*	*90%*
General Service	118%	127%	*9%*	*122%*
General Service (S)	103%	110%	*7%*	*108%*
Small Industrial	109%	98%	*(11%)*	*96%*
Large Industrial	96%	101%	*5%*	*97%*
Lights	79%	66%	*(13%)*	*66%*
Unmetered	106%	108%	*2%*	*104%*
Total	100%	100%		*100%*

In terms of net effect on dollars, the following table illustrates the impact on costs, revenues, RTC ratios from the full four step elimination of the Residential second block:[115]

[115] Estimates of the impact of eliminating the second block are from the response to PEIFA IR 22(i) (Ex. M-12) for residential and farm, and from the attached Excel model for the revisions to the Lighting class

Table 10: MECL 2023 RTC Ratio with Second Block Eliminated and Lights at 95% RTC [116]

	2023 RTC under Status Quo Methods	2023 Revenue ($000s)	plus: second block eliminated, lights at 95% - reduction to GS ($000s)	Revised 2023 Revenue ($000s)	Revised RTC with second block eliminated
Residential (incl S)	91%	134,155	1,602	135,757	92%
Farm	98%	6,224	1,001	7,225	114%
General Service (incl S)	127%	70,942	(3,588)	67,354	120%
Small Industrial	98%	13,443		13,443	98%
Large Industrial	101%	16,360		16,360	101%
Lights	66%	2,250	985	3,235	95%
Unmetered	108%	479		479	108%
Total		243,853	0	243,853	

Based on the above updates to MECL's previous filings, implementing an elimination of the second block for large farms as MECL proposes will cause the Farm class customers to be paying 114% RTC, well above the intended zone of reasonableness.

With respect to MECL's proposal on rate rebalancing certain classes to address RTCs outside of the zone of reasonableness:

> ***CONCLUSION:*** *The IRAC concern that certain classes (particularly General Service) are paying more than their measured costs (i.e., RTC above 105%), while others (particularly Residential and Lighting) are paying less than their measured costs, remains broadly valid. Rebalancing to address this concern is justified.*
>
> ***CONCLUSION:*** *Upward rate adjustments to the Residential (with Farms removed) and Lighting classes are merited, permitting reductions to the General Service class*.

The 2023 COS also shows a continuing trend of cost increases affecting primarily the cost of demand and customer-related services on the system, with little to no increase in the cost of energy-related items, as shown in the Table below:

[116] Second block dollar value impact based on the response to PEIFOA IR-22(i), using 2020 data which might slightly adjust RTC ratios with 2023 updated data. However the farm estimate is only the impact from farms >5,000 kWh/month, not all farms >2,000 kWh/month. As a result, the likely dollar value impact from large farms is likely higher than reported in the table, and the resulting large farm RTC ratio would be even higher than 114% if the MECL proposal was adopted.

Table 11: Unit Costs for Energy versus Demand and Customer-Related Costs in CAS

Systemwide Unit costs (cents/kW.h) (from respective Schedules 1.1)	2017 CAS	2020 CAS	2023 Status Quo Methods	*incr 2017-2023*	*incr (%)*
Energy	8.36	8.20	8.41	*0.05*	*0.6%*
Demand and Customer	6.76	7.53	8.04	*1.28*	*18.9%*
Total	15.12	15.73	16.45	*1.33*	*8.8%*

Given farm customers are larger than normal residential customers, as well as higher load factor, their relative use of energy-related functions will be higher, while the residential class will make more relative use of demand and customer related functions. This further explains the evolution in RTC ratios and why farm RTC ratios continue to increase over the series of studies while residential do not.

> ***CONCLUSION:*** *The relative cost of demand on the system has increased faster than the relative cost of energy*

Appendix B:

Resumes of Melissa Davies and Patrick Bowman

MELISSA DAVIES

CONSULTANT

MNYD Consulting Inc.

mdavies@mnydconsulting.ca

AREAS OF EXPERIENCE:

- Utility Regulation and Rates, including revenue requirement, cost of service and rate design
- System and Resource Planning including supply and load/demand projections and cost modelling including sensitivity and scenario analysis
- Financial and Economic analysis, projections and modelling
- Financial Evaluation including Cost-Benefit Analysis, NPV and Business Valuation

EDUCATION:

- Master of Business Administration (MBA), majors in Finance and Sustainability, Asper School of Business, University of Manitoba, 2015
- Bachelor of Commerce (Honours), major in Actuarial Mathematics, Asper School of Business, University of Manitoba, 2010
- Passed Society of Actuaries Exam FM/2, 2008

PROFESSIONAL EXPERIENCE:

- **For the Association of Major Power Consumers of British Columbia (2014 – Present):** Provide advisory services to the industrial customer group, including expert witness (filing evidence and providing oral testimony), advisory and case management in electric utility revenue requirement (rate applications), rate design, cost of service, and integrated resource planning applications before the British Columbia Utilities Commission, with a focus on general service large and transmission service customers. Assist industrial power users with respect to years long review of changing the Transmission customer rate structure and in development of other rate programs and pilots including the incremental energy rate and the freshet energy rate. Participation in utility and provincially run works on behalf of industrial electricity customers on matters including electrification policy and planning, industrial rate design, long-term resource planning, system interconnection policy, and CleanBC initiatives. Provides ongoing project management and advisory services to the group regarding industrial electricity and economic policy issues.
- **For the Nova Scotia Industrial Group (2023 – Present):** Provide ongoing strategic and technical support on behalf of the Industrial Group (IG) intervenor in the Nova Scotia Power Cost of Service Study (COSS) preparations, including over a dozen

workshops on cost of service related matters in preparation of a COSS Application expected in 2025. Provide technical support to legal counsel on other regulatory matters including review of the E1 DSM Plan and in rate rider applications (FAM AA/BA, storm cost rider).

- **For the City of Langford (2024 – Present):** Provide ongoing technical support to legal counsel and the City of Langford in development of a long-term rate plan and in negotiations of a contract renewal for sewer utility fees owned and operated by West Shore Environmental Services.
- **For the PEI Federation of Agriculture (2022 – Present):** Provide ongoing strategic and technical support in the Maritime Electric Rate Design Application on behalf of PEIFOA farming customers (including residential and small to large general service operations).
- **For JD Irving, New Brunswick (2022 – 2024):** Filed expert evidence and provided technical support in Matter 0529: NB Power Rate Design proceeding on behalf of JD Irving, an industrial customer and intervenor. Provided technical support in Matter 554: NB Power Class Cost Allocation Study.
- **For the City of Surrey District Energy Utility Rate Review Panel (2019 – 2024):** One of three panelists responsible for annual review and recommendation of district energy utility rates for the City of Surrey. Responsibilities include meeting with the energy utility's finance group on an annual basis to provide objective and expert advice regarding utility revenue requirement, rate structure and proposed rates consistent with established rate-setting principles. Panel recommendations are reviewed by the utility and provided to the City Council in their consideration for district energy utility rates.
- **For the Vancouver Airport Fuel Facilities Corporation (2019 – 2021):** Provided technical analysis and consultation in the review of Pembina Kinder Morgan Jet Fuel (PKMJF) 2019 Tariff Application before the British Columbia Utilities Commission. This included providing expert evidence on revenue requirement, cost of service and rate design topics, including the accelerated depreciation proposal of the pipeline due to potential future abandonment.
- **For Manitoba Industrial Power Users Group (2010 – 2020):** Analytical and strategic support for expert and legal services in the intervention in general rate applications and related proceedings which review and analyse Manitoba Hydro's revenue requirement, cost of service, rate design, system resource planning, load forecast, financial targets and analysis, depreciation, and economic conditions. Assist industrial power users with respect to rate design including assessment of alternative rate structures and surplus energy rates. Provided analytical and strategic support for experts and legal services in the inaugural Efficiency Manitoba 3-Year Plan Application for years F2021 – F2023 before the Public Utilities Board. Provided analytical and strategic support for expert and legal services in the 2013 Needs For and Alternatives To (NFAT) review before Manitoba Public Utilities Board representing large industrial energy users in review of $20 billion+ long-term utility resource capital plans. Role for

the NFAT included multi-forum stakeholder engagement with Manitoba businesses and industry to identify and report on energy requirements and resourcing perspectives from this market segment more broadly. Provided long-term project management to the group, with regular reporting, stakeholder engagement, and update meetings to support group energy-related initiatives. Undertook economic impact assessment of the group, including the 2012 and 2015 MIPUG Economic Impact Assessment reports, which surveyed members and reported on the local and regional economic benefits of energy intensive industry in Manitoba.

- **For the Utilities Consumer Advocate of Alberta (2016 – 2020):** Support in review and analysis related to utility rate setting, cost of service, depreciation methodology and rate design before the Alberta Utilities Commission. Specific project work included providing expert evidence on cost of service and rate design in the ATCO Gas Phase II 2020 General Rate Application (#25428). Provided technical support and analysis on depreciation matters in the Altalink Management Ltd. 2017 – 2018 General Tariff Application (GTA) (#21341), the following 2019 – 2021 GTA proceeding (#23848), the AltaGas 2018 Depreciation Application proceeding (#24161), the ATCO Gas 2018 Depreciation Application proceeding (#24188), and the ATCO Pipelines 2017 – 2018 General Rate Application (#22011). Provided technical support and analysis in review of the ATCO Pipelines 2019 – 2020 General Rate Application (#23793) focused on revenue requirement forecasts, the ATCO Pipelines Pembina-Keephills Transmission Pipeline Project review (#23799), and in related interim rate and compliance filing proceedings (#24817).
- **For the Industrial Gas Users, Manitoba (2018 – 2020):** Project management and stakeholder engagement for industrial gas customers, supporting intervention in the Centra Gas 2019 General Rate Application in Manitoba. Support to legal counsel in case strategy and argument development and ongoing technical support for expert witnesses in development of evidence and testimony in the proceeding. Support in the technical areas of revenue requirement, capital expenditures, cost of service methodology, and rate design.
- **For the City of St. John's, Newfoundland (2018 - 2019):** Subcontracted to Forkast Consulting Services to provide an expert report and recommendations regarding the continuation of the water rental rate structure for the City's legislated waterways to Newfoundland Power for use in hydroelectric generation. Research and analysis included a review of relevant Newfoundland legislature, review of Newfoundland Power financial structure and hydroelectric assets, a comparison of other utility rate structures and provincial legislature regarding water rentals and alternative considerations including asset pricing and acquisition considerations. Ultimately the report provided detailed recommendations on rate design, rate collection levels and timing, and supporting rationale for consideration by City and Council.
- **For Saskatchewan Rate Review Panel (2013 – 2019)**: Provided support in regulatory, economic and financial analysis and reporting to provide advice to the Saskatchewan Rate Review Panel on commodity and delivery rate applications

submitted by SaskEnergy and general rate applications by SaskPower, specializing in review of cost of service, rate design, depreciation methods (including cost recovery of stranded assets), financial forecast evaluation (including financial targets), and load forecast.

- **For Northwest Territories Power Corporation (2010 – 2019):** Provided technical support in the filing of General Rate Applications for electricity rate changes before the Northwest Territories Public Utilities Board, including the 2012 and 2017 applications. This includes financial and economic modelling, development of community specific and territory wide load forecasts, preparation of the cost of service study and providing rate design options for residential, general service and wholesale customers. Provided technical support in the 2010 application to implement Electricity Rate Policy Guidelines application. Undertook projects directly for NTPC including research, writing, and development for economic, financial and regulatory policy assessment and strategy.
- **For the Hualapai Tribal Utility Authority (HTUA) (2017 – 2018):** Provided financial analysis to complete a feasibility study and Cost of Service analysis (including financial model) for the development of a municipally owned distribution utility, including power purchase and transmission, asset purchase (acquisition value) and replacement costs, and ongoing operation and maintenance costs. The assignment included a review of comparable jurisdiction cost and rate structures, building a financial model with input cost variables, reporting and presenting in HTUA Board meetings.
- **For the Forks North Portage Corporation (2016 - 2018):** Prepared an economic profile assessing the economic impacts of tourist destination 'The Forks' including quantitative analysis of direct and indirect benefits for Manitoba. Updated economic impact assessment in 2018 following increased development and resulting economic impact on the site on a municipal, provincial and federal level.
- **For City of Penticton (2017):** Provided financial and technical analysis to the City in its stormwater utility rate review, including development of long-term revenue requirement, development of different rate structure options and review of other stormwater utilities in Canadian jurisdictions for comparison of rate options.
- **For Tolko Industries, Hudbay Minerals and Manitoba Hydro (2015 - 2016):** Provided support for a concept study assessing natural gas fuel alternatives (LNG and CNG) for northern Manitoba industry including long-term pricing models and logistical considerations.
- **For Industrial Customers of Newfoundland and Labrador Hydro (2010 – 2014):** Support in the preparation of technical analysis and evidence for Newfoundland Hydro GRA hearings and the rate stabilization plan application before Newfoundland Board of Commissioners of Public Utilities, representing large industrial energy users.
- **For Minaki Cottagers Association (2013 – 2014):** Analyzed and reported on the possible socio-economic effects including economic consumption and supply capacity

of evolving plans to redevelop the former Minaki Lodge site into condominium units with a focus on safety, recreational, cultural and heritage impacts on the existing customers and area. Reviewed past and comparative developments to establish benchmarks for sizing due to the unorganized territory status of Minaki.

- **For Tsay Keh Dene First Nation and Kwadacha First Nation (2011):** Prepared analysis on a comparison between existing rates and proposed changes. Technical support, research, writing and development of Community Energy Study. Assisted in research, analysis and writing for Tsay Keh Dene and Kwadacha First Nations in British Columbia regarding the consultation process of the potential Site C Clean Energy Project.
- **For Manitoba Hydro, Keeyask Generation Project (2010 – 2012):** Provided technical analysis and support for the Keeyask Generation Project economic employment model, assisting with analysis of the economic and socio-economic consequences of the Project. Provide support and research to the Environmental Impact Statement Core document management and executive summary. Assisted in development of a stakeholder socio-economic assessment including cost-benefit analysis and economic evaluation regarding the potential listing of lake sturgeon as an endangered species in Manitoba under Section 1 of the Species at Risk Act.

Utility Regulation Expert Evidence & Testimony					
Utility	**Proceeding**	**Before**	**Client**	**Year**	**Oral Testimony**
BC Hydro	2021 Integrated Resource Plan	British Columbia Utilities Commission (BCUC)	Association of Major Power Customers (AMPC)	2022 - 2024	No
New Brunswick Power	NB Power Rate Design Proceeding (Matter 0529)	New Brunswick Energy & Utilities Board	JD Irving	2022 - 2023	No
BC Hydro	F2023-2025 Revenue Requirements Application (RRA)	BCUC	AMPC	2022 - 2023	Yes
BC Hydro	F2020-2021 RRA	BCUC	AMPC	2019 - 2020	Yes
ATCO Gas	2020 General Rate Application (GRA) - Phase II	Alberta Utilities Commission (AUC)	Alberta Utilities Consumer Advocate (UCA)	2019 - 2020	No
PKM Canada (Jet Fuel)	2019 Jet Fuel Application	BCUC	Vancouver Airport Fuel Facilities Corporation	2019 - 2021	No

Utility Regulation - Advisory, Expert & Legal Support				
Utility	**Proceeding**	**Before**	**Client**	**Year**
BC Hydro	Transmission Rate Rate Design Application	BCUC	AMPC	2022 - 2023
BC Hydro	F2022 RRA	BCUC	AMPC	2020-21
AltaGas	2018 Depreciation Application	AUC	UCA	2019-20
Altalink Management Ltd	2019-20 General Tariff Application	AUC	UCA	2019-20
Efficiency Manitoba	2020/21 - 2022/23 Efficiency Plan	Manitoba Public Utilities Board (MPUB)	Manitoba Industrial Power Users Group (MIPUG)	2019-20
ATCO Gas	2018 Depreciation Application	AUC	UCA	2019-20
ATCO Pipelines	2019-2020 General Rate Application	AUC	UCA	2018-19
ATCO Pipelines	Pembina Keephills Transmission Pipeline Project	AUC	UCA	2018-19
Manitoba Hydro	2019/20 General Rate Application	MPUB	MIPUG	2018-19
Manitoba Hydro	2017/18 & 2018/19 GRA	MPUB	MIPUG	2017-18
Altalink Management Ltd	2017-2018 General Tariff Application	AUC	UCA	2016-17

Utility Regulation - Advisory, Expert & Legal Support				
Utility	**Proceeding**	**Before**	**Client**	**Year**
Northwest Territories Power Corporation (NTPC)	2017/18 & 2018/19 Phase I & II General Rate Application	Northwest Territories Public Utilities Board (NWTPUB)	NTPC	2016-17
ATCO Pipelines	2017-2018 General Rate Application	AUC	UCA	2016-17
CentraGas	2019/20 General Rate Application	MPUB	Industrial Gas Users	2019
ATCO Electric	2018 Depreciation Application	AUC	UCA	2019
SaskPower	2018 Rate Application	Saskatchewan Rate Review Panel (SRRP)	SRRP	2017
SaskPower	2016 and 2017 Rate Application	SRRP	SRRP	2016
Manitoba Hydro	2016 Cost of Service Review	MPUB	MIPUG	2016
SaskEnergy	2015/16 Natural Gas Delivery & Commodity Rate Application	SRRP	SRRP	2015
Manitoba Hydro	2014/15 & 2015/16 General Rate Application	MPUB	MIPUG	2015
Manitoba Hydro	Needs For and Alternatives To (NFAT) Resource Planning Investigation	MPUB	MIPUG	2014
Manitoba Hydro	2012/13 & 2013/14 General Rate Application	MPUB	MIPUG	2013
SaskEnergy	2013/14 & 2014/15 Natural Gas Delivery Rate Application	SRRP	SRRP	2013
NTPC	2012/13 & 2013/14 General Rate Application	NWTPUB	NTPC	2012
NTPC	2010 Rate Rebalancing Application	NWTPUB	NTPC	2010
Manitoba Hydro	2010/11 & 2011/12 General Rate Application	MPUB	MIPUG	2010
Newfoundland and Labrador Hydro (NLH)	Rate Stabilization Plan - Rate Finalization	Board of Commissioners of Public Utilities of Newfoundland and Labrador (NLPUB)	Newfoundland Island Industrial Customers	2010

PATRICK BOWMAN

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Winnipeg, Manitoba
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AREAS OF EXPERIENCE:

- Utility Regulation and Rates, including Depreciation
- Project Development and Planning
- Utility Resource Planning

EDUCATION:

- MNRM (Master of Natural Resources Management), University of Manitoba, 1998
- Bachelor of Arts (Human Development and Outdoor Education), Prescott College (Arizona), 1994

PROFESSIONAL EXPERIENCE:

BOWMAN ECONOMIC CONSULTING INC., WINNIPEG, MANITOBA

2020 – current – Principal Consultant

Conduct consulting assignments as Principal Consultant of new economic consulting firm, focused on utility regulation. Member, Society of Depreciation Professionals

Sample Projects:

For Manitoba Industrial Power Users Group (2020 – present; previous involvement since 1998): Prepare analysis and evidence for regulatory proceedings before Manitoba Public Utilities Board representing large industrial energy users. Appear before PUB as expert in General Rate Application and revenue requirement reviews, the Needs For and Alternatives To (NFAT) resource planning hearing, cost of service, and rate design matters. Assist in regulatory analysis of the purchase of local gas distributor (CentraGas) by Manitoba Hydro. Assist industrial power users with respect to assessing alternative rate structures, surplus energy rates and demand side management initiatives including curtailable rates and load displacement.

For Industrial Customers of Newfoundland and Labrador Hydro (2020 – present; previous involvement since 2001): Prepare analysis and evidence for Newfoundland Hydro GRA and other rate hearings before Newfoundland Board of Commissioners of Public Utilities representing large industrial energy users.

For Industrial Gas Users Association of Manitoba (2020 - present): Support for cost of service and rate design matters. Testimony before the Manitoba Public Utilities Board.

For Northwest Territories Power Corporation (2020-Present; with previous involvement 2000-2020): Provide technical analysis and support regarding General Rate Applications and related Public Utilities Board filings. Assist in preparation of evidence and providing overall guidance to subject specialists in such topics as depreciation and return. Appear before PUB as expert in revenue requirement, cost of service and rate design matters, and on system planning reviews (Required Firm Capacity). Support to Government of the Northwest Territories on Crown utility governance, rate policy matters, and project development.

For the BC Association of Major Power Consumers (2020-Present; with previous since 2014): Support for review of BC Hydro Revenue Requirement, Depreciation, Cost of Service, Rate Design, Interruptible Rates, and stepped industrial rates.

For Northwest Territories Energy Corporation (2021-Present, with previous involvement 2003 - 2013): Provided analysis and support to joint company/local community working groups in development of business case and communication plans related to potential new major hydro and transmission projects. Assist in planning stages and contract review for new LNG supply to Inuvik. Assist in Board of Director's review of corporate roles for commercial versus regulated activities.

For Vale Newfoundland (2022-present): Assist in negotiations regarding new industrial contract and interruptible power framework.

For J. D. Irving Ltd. (2022-Present); previous involvement 2017-2018): Support in regulatory proceedings before the New Brunswick Energy and Utilities Board on matters of Revenue Requirement, customer class and rate design, and smart meter implementation.

For the PEI Federation of Agriculture (2023-present): Support in regulatory review of Maritime Electric Rate Design proceeding.

For the Industrial Group of Nova Scotia Power Inc. (2024-Present): Technical support to Cost of Service working group and negotiations on methodology.

For the City of Langford (2024-present): Assistance in development of alternatives for renegotiation of sewer services supply agreement.

For Yukon Energy Corporation (2024-present): Provide analysis regarding net salvage regulatory account options.

For the Ontario Energy Board (OEB) (2025): Act as facilitator for distribution rate application for Welland Hydro.

For Nelson Hydro (2020-2025; with previous involvement since 2013): Development and updating of a Cost of Service model. Support in regulatory filings before the BC Utilities Commission including Revenue Requirement and Generic Cost of Capital.

For a law firm representing the Government of Alberta (2024): Assistance in calculation of depreciation rates for the purposes of property taxation of industrial property.

For the Manitoba Public Interest Law Centre (2024): Technical support to working group for Brokenhead Ojibway Nation in consultation process with Manitoba Hydro regarding new development and licencing of existing projects on the Winnipeg River and Lake Winnipeg Regulation.

For confidential client (2021-2023): Assist in investigations regarding potential hydrogen development opportunities in Canada.

For Corner Brook Pulp and Paper (2021-2022): Assist in negotiations regarding new industrial contract and interruptible power framework.

INTERGROUP CONSULTANTS LTD., WINNIPEG, MANITOBA

1998 – 2024 – Research Analyst/Consultant/Principal/Senior Associate

Utility Regulation

Conducted research and analysis for regulatory and rate reviews of electric, gas and water utilities in eight Canadian provinces and territories and international. Prepared evidence and expert testimony for regulatory hearings. Assisted in utility capital and operations planning to assess impact on rates and long-term rate stability.

Sample Projects:

For the Office of the Utilities Consumer Advocate of Alberta (2016 - 2024): Analysis and strategic support of Government agency representing the interests of small utility customers. Addressed matters of utility rates and asset depreciation matters, covering electrical transmission, distribution, gas transmission, distribution, project development, and regulated utility service providers.

For the Ontario Energy Board (OEB) (2024): Review regulatory commission policies and practices with respect to intervenor participation, including Consumer Advocate options, budgets, etc.

For the Ontario Energy Board (OEB) staff (2022-2023): Support the OEB staff in the Enbridge Gas Distribution 2024 rate re-basing application, focused on matters of utility assets and depreciation.

For Vancouver Airport Fuel Facilities Corporation (2018-2022): Provide analysis and evidence in support of tolls for common carrier jet fuel pipeline, before the BC Utilities Commission.

For City of Chestermere (2015 - 2022): Analysis of various rate proposal from Chestermere Utilities Inc. to the City of Chestermere.

For a law firm (2021-2022): Provide analysis in support of hydro generation valuation in northwestern Ontario.

For Taxi Coalition of Manitoba (2021): Support for regulated vehicle insurance rate design, provided by Crown insurer. Testimony before the Manitoba Public Utilities Board.

For Jamaica Public Service (2018-2020): Assist in preparation of regulatory rate filing, including cost of service, revenue requirement, and plans to address utility losses and power theft.

For Government of Ontario (2018): Support to department undertaking and supporting preparation of a Modernization Review of the Ontario Energy Board.

For Yukon Energy Corporation (1998 - 2015): Provide analysis and support of regulatory proceedings and normal regulatory filings before the Yukon Utilities Board. Appear before YUB as expert on revenue requirement matters, depreciation, net salvage, cost of service, rate design, and resource planning. Prepare analysis of major capital projects, financing mechanisms to reduce rate impacts on ratepayers.

For City of Swift Current (2013 - 2014): Utility system valuation.

For Municipal Customers of City of Calgary Water Utility (2012 - 2013): Analysis of proposed new development charges and reasonableness of water and wastewater rates (City of Chestermere, City of Airdrie, Town of Cochrane, and Town of Strathmore).

For Yukon Development Corporation (1998 - 2012): Prepare analysis and submission on energy matters to Government. Participate in development of options for government rate subsidy programs. Assist with review of debt purchase, potential First Nations investment in utility projects, and corporate governance.

For NorthWest Company Ltd. (2004 - 2006): Review rate and rider applications by Nunavut Power Corporation (Qulliq Energy), provide analysis and submission to rate reviews before the Utility Rates Review Council.

Project Development, Socio-Economic Impact Assessment and Mitigation

Provide support in project development, local investment opportunities or socio-economic impact mitigation programs for energy projects, including northern Manitoba, Yukon, and NWT. Support to local communities in resolution of outstanding compensation claims related to hydro projects.

Sample Projects:

For Government of Canada – Justice (2022-2023): Provide opinion evidence for proceeding before the Specific Claims Tribunal regarding transmission line valuation for 1950s transmission line crossing reserve land.

For the Government of the NWT (2021-2023): Assist in developing rate strategies and operational costing for major new generation and transmission facilities in NWT.

For Kivalliq Hydro-Fibre Link (2020-2022): Review and provide comment on drafts of business case for new transmission and fibre optic link to Nunavut.

For Hualapai Tribal Utilities (2017-2018): Support Tribal utility association in preparation of feasibility study to take over operations of power distribution on tribal lands.

For Government of NWT (2015-2016): Assist in analysis for hydro system resiliency study in response to Snare River drought.

For New World Dairy (2015-2017): Assist in negotiations regarding Non-Utility Generation and interconnection with Newfoundland Hydro

For Yukon Energy Corporation (2005 - 2015): Participated in preparation of resource plans, including Yukon Energy's 20-Year Resource Plan Submission to the Yukon Utilities Board in 2005 (including providing expert testimony before the YUB), advisor on 2010 update. Project Manager for all planning phases of the Mayo B hydroelectric project ($120 million project) including environmental assessment and licencing, preliminary project design, preparation of materials for Yukon Utilities Board hearing, joint YEC/First Nation working group on all technical matters related to project including fisheries, managing planning phase financing and budgets. Assistance in preparation of assessment documentation for Whitehorse LNG generation project.

For Northwest Territories Power Corporation (2005 - 2012): Participate in planning stages of $37 million dam replacement project; appear before Mackenzie Valley Land and Water Board (MVLWB) regarding environmental licence conditions; participate in contractor negotiations, economic assessments, and ongoing joint company/contractor project Management Committee. Provide economic and rate analysis of potential major transmission build-out interconnect to southern jurisdictions. Conduct business case analysis regulatory review of projects $400,000-$5 million, and major PUB Project Permit reviews of projects >$5 million.

For Tolko Manitoba (2014-2015): Assist in negotiations with Manitoba Hydro regarding expansion of steam generation capabilities.

For Kwadacha First Nation and Tsay Keh Dene (2002 - 2004): Support and analysis of potential compensation claims related to past and ongoing impacts from major northern BC hydroelectric development. Review options related to energy supply, including change in management contract for diesel facilities, potential interconnection to BC grid, or development of local hydro.

For Manitoba Hydro Power Major Projects Planning Department (1999 - 2002): Initial review of socio-economic impacts of proposed new northern generation stations and transmission. Participate in joint working group with client and northern First Nation on project alternatives (such as location of project infrastructure).

For Manitoba Hydro Mitigation Department (1999 - 2002): Provided analysis and process support to implementation of mitigation programs related to past northern generation projects, debris management program. Assist in preparation of materials for church-led inquiry into impacts of northern hydro developments.

For International Joint Commission (1998): Analysis of current floodplain management policies in the Red River basin, and assessment of the suitability of alternative floodplain management policies.

For Nelson River Sturgeon Co-Management Board (1998 and 2005): An assessment of the performance of the Management Board over five years of operation and strategic planning for next five years.

GOVERNMENT OF NORTHWEST TERRITORIES, YELLOWKNIFE, NORTHWEST TERRITORIES
1996 – 1998 Land Use Policy Analyst

Conducted research into protected area legislation in Canada and potential for application in the NWT. Primary focus was on balancing multiple use issues, particularly mining and mineral exploration, with principles and goals of protection.

Patrick Bowman - Experience in Utility Regulatory Proceedings

Utility	Proceeding	Work Performed	Before	Client	Year	Oral Testimony
Yukon Energy Corporation	Final 1997 and Interim 1998 Rate Application	Analysis and Case Preparation	Yukon Utilities Board (YUB)	Yukon Energy	1998	No
Manitoba Hydro	Curtailable Service Program Application	Analysis, Preparation of Intervenor Evidence and Case Preparation	Manitoba Public Utilities Board (MPUB)	Manitoba Industrial Power Users Group (MIPUG)	1998	No
Yukon Energy	Final 1998 Rates Application	Analysis and Case Preparation	YUB	Yukon Energy	1999	No
Westcoast Energy	Sale of Shares of Centra Gas Manitoba, Inc. to Manitoba Hydro	Analysis and Case Preparation	MPUB	MIPUG	1999	No
Manitoba Hydro	Surplus Energy Program and Limited Use Billing Demand Program	Analysis and Case Preparation	MPUB	MIPUG	2000	No
West Kootenay Power	Certificate of Public Convenience and Necessity - Kootenay 230 kV Transmission System Development	Analysis of Alternative Ownership Options and Impact on Revenue Requirement and Rates	British Columbia Utilities Commission (BCUC)	Columbia Power Corporation/Columbia Basin Trust	2000	No
Northwest Territories Power Corporation (NTPC)	Interim Refundable Rate Application	Analysis and Case Preparation	Northwest Territories Public Utilities Board (NWTPUB)	Northwest Territories Power Corporation (NTPC)	2001	No
NTPC	2001/03 Phase I General Rate Application	Analysis and Case Preparation	NWTPUB	NTPC	2000 - 2002	No - Negotiated Settlement
Newfoundland Hydro	2002 General Rate Application	Analysis, Preparation of Intervenor Evidence and Case Preparation	Board of Commissioners of Public Utilities of Newfoundland and Labrador (NLPUB)	Newfoundland Industrial Customers	2001 - 2002	No
NTPC	2001/02 Phase II General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2002	Yes
Manitoba Hydro/Centra Gas	Integration Hearing	Analysis and Case Preparation	MPUB	MIPUG	2002	No
Manitoba Hydro	2002 Status Update Application/GRA	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2002	Yes
Yukon Energy	Application to Reduce Rider J	Analysis and Case Preparation	YUB	Yukon Energy	2002 - 2003	No
Yukon Energy	Application to Revise Rider F Fuel Adjustment	Analysis and Case Preparation	YUB	Yukon Energy	2002 - 2003	No
Newfoundland Hydro	2004 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	NLPUB	Newfoundland Industrial Customers	2003	Yes
Manitoba Hydro	2004 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2004	Yes
NTPC	Required Firm Capacity/System Planning hearing	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2004	Yes
Nunavut Power (Qulliq Energy)	2004 General Rate Application	Analysis, Preparation of Intervenor Submission	Nunavut Utility Rate Review Commission (URRC)	NorthWest Company (commercial customer intervenor)	2004	No
Qulliq Energy	Capital Stabilization Fund Application	Analysis, Preparation of Intervenor Submission	URRC	NorthWest Company	2005	No
Yukon Energy	2005 Required Revenues and Related Matters Application	Analysis, Preparation of Company Evidence and Expert Testimony on all areas of Revenue Requirement, including Depreciation	YUB	Yukon Energy	2005	Yes
Manitoba Hydro	Cost of Service Methodology	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2006	Yes
Yukon Energy	2006-2025 Resource Plan Review	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2006	Yes
Newfoundland Hydro	2006 General Rate Application	Analysis, Preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2006	No - Negotiated Settlement
NTPC	2006/08 General Rate Application Phase I	Analysis, Preparation of Company Evidence & Expert Testimony on all areas of Revenue Reqt, COS and Rate Design, incl Depreciation	NWTPUB	NTPC	2006 - 2008	Yes
Manitoba Hydro	2008 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	MPUB	MIPUG	2008	Yes
Manitoba Hydro	2008 Energy Intensive Industrial Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2008	Yes
Yukon Energy	2008/2009 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2008 - 2009	Yes
FortisBC	2009 Rate Design and Cost of Service	Analysis and Case Preparation, Support to Legal Counsel	BCUC	BC Municipal Electrical Utilities	2009 - 2010	No
Yukon Energy	Mayo B Part III Application	Analysis, Preparation of Company Evidence	YUB	Yukon Energy	2010	No

Patrick Bowman - Experience in Utility Regulatory Proceedings

Utility	Proceeding	Work Performed	Before	Client	Year	Oral Testimony
Yukon Energy	2009 Phase II Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2009 - 2010	Yes
Newfoundland Hydro	Rate Stabilization Plan (RSP) Finalization of Rates for Industrial Customers	Analysis, Preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2010	No
Manitoba Hydro	2010/11 and 2011/12 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2010 - 2011	Yes
NTPC	Bluefish Dam Replacement Project	Analysis, Preparation of Company Evidence and Expert Testimony	Mackenzie Valley Land and Water Board	NTPC	2011	Yes
Newfoundland Hydro	Depreciation Methodology	Analysis, Support of Expert Witness, Advisor to Legal Counsel	NLPUB	Newfoundland Industrial Customers	2012	No
NTPC	2012/14 General Rate Application	Analysis, Preparation of Company Evidence & Expert Testimony on all areas of Revenue Reqt, COS and Rate Design, incl Depreciation	NWTPUB	NTPC	2012	Yes
Manitoba Hydro	2012/13 and 2013/14 General Rate Application	Analysis, Preparation of Intervenor Evidence & Expert Testimony on all areas of Revenue Reqt, COS and Rate Design, incl Depreciation	MPUB	MIPUG	2013	Yes
Manitoba Hydro	Needs For and Alternatives To Investigation	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2014	Yes
Manitoba Hydro	2015/16 General Rate Application	Analysis, Preparation of Intervenor Evidence & Expert Testimony on all areas of Revenue Reqt, COS and Rate Design, incl Depreciation	MPUB	MIPUG	2015	Yes
Newfoundland Hydro	Amended 2013 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	NLPUB	Newfoundland Industrial Customers	2015	No - merged into 2015 General Rate Application
Newfoundland Hydro	2015 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	NLPUB	Newfoundland Industrial Customers	2015	Yes
Manitoba Hydro	2016 Cost of Service review	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2016	Yes
Chestermere Utilities Inc.	2017 Rate Increase Request	Analysis, Preparation of Rate Review	City of Chestermere City Council	City of Chestermere City Council	2016	Presentation to Council
Newfoundland Hydro	2017 General Rate Application	Pre-Filed Testimony and Negotiated Settlement, including Depreciation	NLPUB	Newfoundland Industrial Customers	2017 - 2018	No - Negotiated Settlemen
Altalink Management Limited	2017-18 General Tariff Application	Analysis, Support of Consumer Advocate during Negotiated Settlement Process on Depreciation matters	Alberta Utilities Commission (AUC)	Alberta Utilities Consumer Advocate (UCA)	2016 - 2017	No - Negotiated Settlemen
ATCO Pipelines	2017-18 General Rate Application	Analysis, Preparation of Intervenor Evidence on Depreciation matters	AUC	UCA	2016 - 2017	No - Written Process only
Manitoba Hydro	2017/18 and 2018/19 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2017 - 2018	Yes
ATCO Pipelines	2017-18 GRA Review and Vary	Analysis and Case Preparation for SCADA Depreciation	AUC	UCA	2017 - 2018	No
ATCO Pipelines	2019-20 General Rate Application	Analysis, Preparation of Intervenor Evidence including Depreciation	AUC	UCA	2018	No - Written Process only
Altalink Management Limited	2019-21 General Tariff Application	Analysis, Support of Consumer Advocate during Negotiated Settlement Process on depreciation matters, Preparation of Intervenor Evidence and Expert Testimony	AUC	UCA	2018	Yes
Newfoundland Hydro	Cost of Service Methodology	Analysis and Case Preparation	NLPUB	Newfoundland Industrial Customers	2018	No
ATCO Pipelines	Keephills Transmission Facilities Assessment	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2018 - 2019	No - Written Process only
Manitoba Hydro	2019/20 Electric Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2019	Yes
Chestermere Water, Wastewater, Stormwater and Solid Waste Utility	2019 Rate Request	Analysis, Preparation of Rate Review	City of Chestermere City Council	City of Chestermere City Council	2019	Presentation to Council
ATCO Electric Distribution	Distribution Depreciation	Analysis and Case Preparation	AUC	UCA	2019	No
AltaGas	Distribution Depreciation	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2019	No - Written Process only

Patrick Bowman - Experience in Utility Regulatory Proceedings

Utility	Proceeding	Work Performed	Before	Client	Year	Oral Testimony
ATCO Gas	Distribution Depreciation	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2019	No - Written Process only
Nalcor Energy, Newfoundland and Labrador Hydro	Muskrat Falls Rate Mitigation Hearing	Analysis, Preparation of Intervenor Evidence and Expert Testimony. Included Depreciation Rate Mitigation Options	NLPUB	Newfoundland Industrial Customers	2019	Yes
Kinder Morgan Canada (Jet Fuel) Inc.	2019 Tariff Filing Application	Review pipeline tolling application on revenue requirement and depreciation, prepare interrogatories and draft issues for evidence	BCUC	Vancouver Airport Fuel Facilities Corporation (VAFFC)	2019 - 2021	No
BC Hydro	Fiscal 2020 to 2021 Revenue Requirements Application	Analysis, Preparation of Intervenor Evidence	BCUC	Association of Major Power Consumers of BC (AMPCBC)	2019-2020	Yes
FortisAlberta	Town of Fort Macleod RCN-D Valuation Application	Analysis, Preparation of Intervenor Evidence on Depreciation and Valuation matters	AUC	UCA	2019-2020	No - Written Process only
Manitoba Public Insurance	2021 General Rate Application	Review insurer evidence, draft IRs and prepare evidence on regulatory and rate setting principles	MPUB	Taxicab Coalition	2020	Yes
ATCO Gas	2020 Cost of Service and Phase II Application	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2020	No - Written Process only
Chestermere Water, Wastewater, Stormwater and Solid Waste Utility	2021 Rate Request	Analysis, Preparation of Rate Review	City of Chestermere City Council	City of Chestermere City Council	2020	Presentation to Council
ATCO Pipelines	Acquisition of Pioneer Pipeline	Review evidence, draft IRs. Evidence	AUC	UCA	2020	No - Written Process only
ATCO Electric Transmission	2020-2022 GTA Depreciation Expert	Analysis and support of intervenor evidence	AUC	UCA	2020-2021	No - Written Process only
Direct Energy Regulated Services (DERS)	2020-2022 DRT and RRT Application	Analysis, Support of Consumer Advocate during Negotiated Settlement Process	AUC	UCA	2021	No - Negotiated Settlement
AltaLink Management Ltd.	2022-23 General Tariff Application, and Review and Variance Application	Analysis, Support of Consumer Advocate during Negotiated Settlement Process, Preparation of Intervenor Evidence on Depreciation Matters.	AUC	UCA	2021-2022	No - Written Process only
Manitoba Hydro	2021 Interim Rate Application, Review and Variance Application	Analysis, Support of Intervenor position	MPUB	MIPUG	2021	No
NTPC	2022/23 General Rate Application, Interim Rate Application, and Taltson Hydro Major Project Permit Application	Analysis, support preparation of utility filing, responses to IRs on matters of revenue requirement, rate design and depreciation	NWT PUB	NTPC	2022	No
Nelson Hydro	Cost of Service and Rate Design Proceeding and 2022 Revenue Requirements proceeding	Support to Nelson Hydro on preparation of Cost of Service model and specified studies	BCUC	Nelson Hydro	2020-2022	No
Epcor Distribution and Transmission Inc (EDTI)	EDTI Phase II (Cost of Service and Rate Design) Distribution Tariff AUC proceeding 27018	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2022	No - Written Process only
Newfoundland Hydro	Electrification, Conservation and Demand Management	Analysis, Preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2021-2022	No - Written Process only
Centra Gas Manitoba	2021 Cost of Service Methodology	Analysis, Preparation of Intervenor Evidence	MPUB	Industrial Gas Users of Manitoba (IGU)	2021-2022	No - Written Process only
BC Hydro	Fiscal 2022 to 2025 Revenue Requirements Application	Analysis, Preparation of Intervenor Evidence, primarily focused on depreciation	BCUC	AMPCBC	2022	Yes
DERS	2023 DRT and RRT Application	Analysis, Support of Consumer Advocate during Negotiated Settlement Process	AUC	UCA	2023	No - Negotiated Settlement and written process
EDTI	2023-2025 Transmission Facility Owner Revenue Requirement	Analysis, Preparation of Intervenor Evidence on Depreciation	AUC	UCA	2023	No - Negotiated Settlement
ENMAX Power Corporation (EPC)	2023-2025 Transmission General Tariff Application	Analysis, Preparation of Intervenor Evidence on Depreciation	AUC	UCA	2023	No - Negotiated Settlement and written process
BC Hydro	2021 Intergrated Resource Plan	Analysis, Preparation of Intervenor Evidence	BCUC	AMPCBC	2023	Yes
Enbridge Gas Inc (EGI)	2024 Rebasing	Analysis, Preparation of Intervenor Evidence	Ontario Energy Board (OEB)	OEB Staff	2023	Yes
New Brunswick Power	Matter 529 - 2022 Rate Design Application	Analysis, Preparation of Intervenor Evidence	New Brunswick Energy and Utilities Board	J. D. Irving	2023	Yes
Manitoba Hydro	2023-24 and 2024-25 GRA	Analysis, Preparation of Intervenor Evidence	MPUB	MIPUG	2023	Yes

Patrick Bowman - Experience in Utility Regulatory Proceedings

Utility	Proceeding	Work Performed	Before	Client	Year	Oral Testimony
Manitoba Hydro	SCT 4002-12 Brokenhead Ojibway FN vs HMTK	Opinion on Transmission Line Valuation	Specific Claims Tribunal	Government of Canada	2023	No - Negotiated Settlement
NTPC	Hay River Franchise Disposition	Analysis, support preparation of regulatory principles, rate impacts	NWT PUB	NTPC	2024	Yes
Nelson Hydro	Generic Cost of Capital Review - Stage 2	Support to Nelson Hydro on preparation of utility evidence	BCUC	Nelson Hydro	2024	No
New Brunswick Power	Matter 554 - Class Cost Allocation Study Methodology Review	Analysis, Preparation of Intervenor Evidence	New Brunswick Energy and Utilities Board	J. D. Irving	2024	Yes
Naka Power (NWT)	2025 General Rate Application	Analysis, Preparation of Intervenor Evidence	NWT PUB	NTPC	2025	Yes
NTPC	2024-25 and 2025-26 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2025	Yes
Centra Gas Manitoba	2025 General Rate Application	Analysis, Preparation of Intervenor Evidence	MPUB	IGU	2025	Yes
Fortis BC	2025 Cost of Service and Revenue Rebalancing	Analysis, Support of Intervenor position	BCUC	BC Municipal Electrical Utilities	2025	No
Nova Scotia Power	M11475 Cost of Service Study	Analysis, Support of Intervenor position	Nova Scotia Energy Board	Industrial Group (IG)	2024-ongoing	pending