June 30, 2020

Island Regulatory & Appeals Commission
PO Box 577
Charlottetown PE C1A 7L1

Dear Commissioners:

Pursuant to IRAC Order UE19-08, please find attached the Company's comprehensive Rate Design Study (the Study) as prepared by independent expert Robert P. Boutilier, P. Eng. dated June 29, 2020. The Study outlines a number of key findings and recommendations regarding the elimination of the Residential rate class second block, the migration of farm customers to the Small Industrial rate class, the need to gather and analyze additional metering data for the Residential and General Service rate classes, and the potential application of time-of-use rates to address electric vehicle charging load impacts and on-Island capacity concerns.

To date, the COVID-19 pandemic has prevented Maritime Electric from performing stakeholder consultations, a necessary step in developing a proposed rate structure incorporating the Study's findings and meeting Order UE19-08 timeliness to achieve revenue to cost (RTC) ratios for all rate classes between 95-105 per cent by March 1, 2022. As outlined in the Company's Farm Rate Study (Appendix C of the Rate Design Study), without mitigation measures, Farm customer bill increases may be as high as ten to twenty per cent on transition to the Small Industrial rate class and twenty to twenty-five per cent if remaining in the Residential rate class upon the elimination of the second block.

Nevertheless, Maritime Electric is optimistic that the consultation process can be conducted in the coming months so that a proposed rate structure can be developed that incorporates stakeholder feedback and any further direction from the Commission based upon its review of this filing. With this information and feedback in hand, Maritime Electric proposes to submit its plan for a proposed rate structure that builds upon the Commission's pending decision on the 2020-2021 General Rate Application and sets out a path that will see the elimination of the Residential second block and achieving RTC ratios between 95 to 105 per cent for all classes by March 1, 2022.

Yours truly,

MARITIME ELECTRIC

Jason C. Roberts
Vice President,
Finance & Chief Financial Officer

JCR23

ELECTRIC RATE DESIGN STUDY

Provided to MARITIME ELECTRIC COMPANY, LIMITED

Prepared by: Robert P. Boutilier, P.Eng.

June 29, 2020

Electric Rate Design Study

Prepared for

Maritime Electric Company, Limited

Robert P. Boutilier, P.Eng, June 29, 2020

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APPENDICES

Executive Summary

In November 2018, Maritime Electric Company, Limited (MECL) filed a General Rate Application which, in response to an Island Regulatory and Appeals Commission (IRAC) directive, contained information and recommendations with respect to rate design and the impact on the various rate classes.

IRAC did not approve the changes as filed and in the Cost and Rates section of its September 27, 2019 GRA Order, IRAC:

- Stated that rates charged from March 1, 2018 to February 28, 2019 shall continue in effect until February 28, 2020 pending review of MECL 2019 Year-end Financials
- Did not approve MECL's requested changes to rural residential service charge or the proposed increase in residential first block energy size
- Ordered that MECL is to submit a "Comprehensive Rate Design Study and Proposed Rate Structure" by June 30, 2020
- Stated that the proposed structure will provide Revenue-to-Cost (RC) ratios between 90% and 110% with longer term goal of reaching 95% to 105%
- Stated that the classification of costs set forth in the Point Lepreau Cost Allocation Classification Study are approved as filed

In response to the Commission's Order, MECL retained the consulting services of Mr. Robert P. Boutilier, P.Eng (the "Consultant") in December 2019[1]. This report provides the comprehensive rate design study requested.

The study provides discussion and commentary regarding:

- The nature and composition of electric rate classes
- The types of electric rate components; their purposes and general usage by type of class
- Comparison of MECL class and rate structures with sampled Canadian utilities
- Recommended changes to MECL tariffs

Summary of Findings and Recommendations

As discussed in further detail in this report, the Consultant's conclusions are summarized below.

1. The Residential rate must increase to bring its R/C ratio into the 95-105 range. The General Service rate must decrease to also fall within this range. The manner in which this takes place must take care to consider customer impacts, from both an overpayment and underpayment perspective, and should also consider any special circumstances which the COVID-19 pandemic may present during re-establishment of the economy.
2. The declining second block residential energy rate should be phased out by increasing the charge over a suitable but short period of time until it is equivalent to the first block charge, and then eliminated.
3. Large farms should be offered the choice of being served under this modified residential tariff or moving to the Small Industrial tariff. MECL should work with its customers to assist them in this decision based upon their load characteristics.
4. The residential Urban and Rural Service Charges should be set in common, using the Urban charge as proposed by MECL. Since this will result in all components of the rates being identical, the Rural rate should be eliminated. This is the same for the Residential Seasonal (rate code 131). I

[1] For Mr. Boutilier's CV please refer to Appendix E.

believe the Residential Seasonal (meter reading and billing) Option (rate code 133) should remain for customer billing convenience.

5. The interval metering projects already underway by MECL relating to farm load and more detail regarding Residential and General Service customers should continue with data archived and analyzed. This information should prove useful for further future cost causation and rate analysis.
6. When sufficient metering data is available, MECL should consider splitting its General Service class into subgroups which may be more homogeneous in nature and provide more accurate relationships between costs and revenues.
7. There is little to no predictable variation in MECL's contracted energy procurement costs within a calendar year. As discussed by MECL in its recent ECAM submission to IRAC[2], although the utility purchases the vast majority of its capacity and energy requirements under contracts, it remains exposed to unforeseeable cost variances that may result from factors beyond its control. As a result of this unpredictability, other than experimenting with rates which could help to avoid building the system peak year to year, there is little benefit in MECL introducing broad based time-of-use rates at this time. Such rates are usually designed to target predictable or probable periods of cost variance. However, as electric-intensive technologies such as at-home charging of electric vehicles are adopted, opportunities to develop targeted time-of-use rates should be considered.

[2] Section 5.0, MARITIME ELECTRIC COMPANY, LIMITED, COMPREHENSIVE REVIEW OF THE ENERGY COST ADJUSTMENT MECHANISM, June 1, 2020

Introduction

Since early in its history electricity has been a regulated service, meaning that its provision, price and services have been overseen by agencies whose purpose is to facilitate the service while protecting the public good at fair and equitable cost. This is largely because electricity is seen as an essential service, the equipment required to produce and distribute electricity is specialized, expensive and requires expertise for safe operation and reliable energy delivery, as well as the consideration that some equipment, particularly transmission and distribution, is better shared than unnecessarily replicated whenever possible.

While the industry has evolved over time and some jurisdictions have moved to open markets for some aspects of the service (largely generation and retail), many other jurisdictions have maintained use of Cost of Service Regulation for most if not all aspects of power supply, delivery and retail. Cost of Service Regulation is applied in PEI, however the introduction of an open access transmission tariff (OATT) provides a degree of market opening.

Maritime Electric Company, Limited ("Maritime Electric", "MECL", or the "Company") is a public utility subject to the PEI Electric Power Act ("EPA" or the "Act") engaged in the production, purchase, transmission, distribution and sale of electricity within Prince Edward Island. Maritime Electric is the primary provider of electricity on PEI delivering over 90 per cent of the energy supplied on the Island. Its System Operator manages power supplied by New Brunswick, MECL generators, and from renewable generation suppliers on the island. The Company's head office is located in Charlottetown with generating facilities in Charlottetown and Borden-Carleton. The Company has contractual entitlement to 30 MW of capacity and associated energy from NB Power's Point Lepreau nuclear generating station and an agreement for the purchase of capacity and system energy from NB Power delivered via four submarine cables. The cables are leased from the Province of Prince Edward Island. The Company also purchases 92.5 MW of wind powered energy under contract with the PEI Energy Corporation.

As a "public utility" MECL is subject to regulatory oversight and approvals of the Island Regulatory and Appeals Commission ("IRAC" or the "Commission"). The Commission's jurisdiction to regulate public utilities is founded in both the Electric Power Act and the Island Regulatory and Appeals Commission Act, R.S.P.E.I. 1988, Cap. I-11 (the "IRAC Act"). Under cost of service regulation, MECL's forecast total cost of operation, including an approved return to its shareholder, is reviewed and tested by IRAC. This cost is known as the utility's Revenue Requirement. A Cost of Service Study is done from time to time to check on how well the revenues collected from the various classes of customers match the corresponding estimated costs of providing service.

Electric rates are designed and applied by customer class, such that their summation is calculated to recover the forecast Revenue Requirement of the Company. The goal is to set rates which, when applied to forecast customer usage by class, return revenues which closely match the cost of providing service to each class. The accuracy of this revenue and cost matching (the "revenue to cost ratio", R/C ratio) is reviewed during IRAC rate review proceedings.

The Commission is required, in accordance with the EPA, to set rates, tolls and charges for electric service that are "reasonable, publicly justifiable, and non-discriminatory". In doing so, the Commission must balance the interests of ratepayers and the interests of the utility.

Over the past several years, these reviews have indicated that some structural rate changes may be required and that some rate classes are over-recovering their allocated costs while others are underrecovering. In particular, the declining block rate structure in the Residential class has been under discussion for more than a decade. Changes were proposed in 2015, however these were deferred by the approved General Rate Agreement of 2016 which set rates until February 28, 2019.

At that time, MECL proposed to consult with stakeholders and conduct a Rate Design Study to address R/C ratios including the appropriateness of the declining block structure of the residential class. In 2016, IRAC ordered MECL to conduct and file a Rate Design Study by April 30, 2018. On April 9, 2018 MECL requested a delay in the Rate Design Study until the earlier of October 31, 2018 or when the Company files its next General Rate Application. On April 17, 2018, the Commission issued Order UE18-02 approving the Company's request.

In November 2018, MECL filed its General Rate Application which contained information and recommendations with respect to rate design and the impact on the various rate classes. IRAC did not approve the changes as filed and in the Cost and Rates section of its September 27, 2019 GRA Order, IRAC:

- Stated that rates charged from March 1, 2018 to February 28, 2019 shall continue in effect until February 28, 2020 pending review of MECL 2019 Year-end Financials
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3. Large farms should be offered the choice of being served under this modified residential tariff or moving to the Small Industrial tariff. MECL should work with its customers to assist them in this decision based upon their load characteristics.
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[3] Section 5.0, MARITIME ELECTRIC COMPANY, LIMITED, COMPREHENSIVE REVIEW OF THE ENERGY COST ADJUSTMENT MECHANISM, June 1, 2020

Maritime Electric Energy Supply Costs

As shown in Schedule 8-1[4] of MECL's 2018 GRA, the vast majority of the electricity delivered by MECL is provided through contractual arrangements with NB Power (Point Lepreau Entitlement and Energy Purchase Agreements) and from on-Island wind generators. Contractual arrangements with NB Power provide capacity and energy unit costs which are fixed on an annual basis out to February 29, 2024. Wind generation is purchased under long term contracts with PEI Energy Corporation.

Schedule 8-1						
Forecast of Energy Costs by Source (%)						
	2016 Actual	**2017 Actual**	**2018 Forecast**	**2019 Forecast**	**2020 Forecast**	**2021 Forecast**
Point Lepreau Entitlement	18.9	20.3	18.7	18.9	17.7	17.5
Energy Purchase Agreement (System Energy)	53.7	51.8	51.7	49.7	49.1	45.2
On-Island Renewable (Wind)	21.4	19.8	20.6	19.7	21.5	25.7
Transmission, Interconnection & Other Charges	1.5	4.0	5.5	8.7	9.0	8.9
Company Generation Costs	4.5	4.1	3.6	3.0	2.7	2.6
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

These contractual arrangements provide a degree of forecast price stability and predictability. Except for system emergencies or unforeseen circumstances, there is generally little to no predictable short term variability in demand or energy costs to MECL. Contract prices are not predicted to vary by season, peak/off-peak or on an hourly basis within a year. This does not mean MECL's energy and capacity costs do not vary, simply that they can vary due to unforeseen and often external factors[5]. These factors include variance from load forecasts, performance of the Point Lepreau, fuel prices, market forces, weather, the economy, changing government policy and regulations both within and outside its service area.

Rate Structures

Electric "tariffs" comprise the various rate components and rates (e.g.; $/kW or $/kWh) that a utility uses to recover its costs from various customer classes. Under Cost of Service regulation, the goal is to charge customers approximately what it costs to serve them, recognizing different situations and cost causations. As a result, for cost determination and revenue collection purposes, a utility's customers are divided into different subgroups called "classes", grouping together customers determined to have similar uses for electricity. A Cost Allocation Study (CAS) analyzes, assigns and allocates total costs to the various classes on either a historical or forecast basis. Rate structures and rates are developed to recover revenues from the classes which are close to the costs required to serve them, as guided by the Cost Allocation Study.

Matching rate structure to the cost types allocated by class increases the chances that inefficient behaviors are lessened, adequate class revenue will be collected, resources required to serve the class will be efficiently utilized, and subsidies within the class are reduced[6].

[4] MECL November 2018 GRA, page 43

[5] See Section 5.0, MARITIME ELECTRIC COMPANY, LIMITED, COMPREHENSIVE REVIEW OF THE ENERGY COST ADJUSTMENT MECHANISM, June 1, 2020

[6] Reference http://files.brattle.com/files/5811_brattle_tariff_design_best_practices_june_2016.pdf

"Rate structure" refers to the mechanisms employed to collect revenue for various types of costs. For example, energy costs are generally recovered as cents per kWh (i.e.; the "rate") of consumption, fixed costs such as generation are collected by employing dollars per kW of the customer's maximum demand. While there are a wide variety of mechanisms which are designed for various reasons such as to send price signals to customers, or to balance the recovery of fixed and variable costs to the utility, collectively they are referred to as the rate structure. Rate structure is a matter of choice and design and can be modified to suit changing needs and conditions.

MECL's rate classes and structures result from the Maritime Electric Company, Limited Act (1994) which stipulated that the PEI rate structure would be the same as that used in New Brunswick, including as it may change from time to time. This Act was repealed in 2003 and superseded by the Electric Power Act. To date, while rates themselves have been adjusted over time, the rate class structure has essentially remained unchanged with the exception of the addition of OATT and net metering arrangements.

Reviewing rate structure from time to time is beneficial. It can highlight changes which can help to avoid or reduce subsidization among, or even within customer classes. Cross subsidization is considered to occur when the revenue to cost ratio (R/C ratio) for a class falls outside of the range set as being acceptable. IRAC has ordered MECL to bring all R/C ratios to 90-110% in the short term, and ultimately to between 95-105%. This means that the revenue received from a class will match the allocated costs by +/- 10% in the near term, and to within +/- 5% in the longer term.

A review and updated understanding of a utility's rate structure provides the utility with better understanding of cost causation and revenue sources which can be used to develop plans and rate structures which better meet changing customer and utility needs[7]. Rate structure review can assist in maintaining fair and equitable cost recovery including any necessary increases/decreases in rates, recognizing the various impacts changes may have on customer groups.

In addition, periodic rate studies provide a focus on the way in which revenue is collected, and highlight opportunities to adjust as may be necessary to send appropriate price signals.

Structures and Mechanisms in Use

Classes and Customer Groupings

There are a wide variety of class structures in use across jurisdictions. Customer groupings, or classes, have been designed with many considerations in mind which also vary by jurisdiction. Essentially however, the majority of classes are designed to reflect common electricity cost causation factors and usage behaviours. As a result, classes are most often based on the nature of the customer or enterprise consuming electricity; residential, commercial/general, or industrial. Depending upon the variety of customers within these broad sectors, utilities may separate customers into further subgroups, often by service requirements, magnitude of demand and/or energy requirements.

The selection of the number and type of rate classes used by a utility is a matter of choice and regulatory approval. As stated, MECL's current rate class structure was set by legislation in 1994 and required to be

[7] For example, the effects of growth in customer-owned renewable generation, or growth in electric loads such as the charging of electric vehicles

identical to that used in New Brunswick. While the MECL Act was repealed in 2003, the rate class structure has remained essentially intact.

MECL's 2019 class structure and share of annual energy requirement is as follows[8]:

- Residential
  - Urban 16%
  - Rural 32%
  - Seasonal 2%
- General Service 30%
  - Seasonal Operators Option 1%
- Small Industrial 7%
- Large Industrial 12%
- Wholesale
- Street and Yard Lighting
- Unmetered
- Miscellaneous
- Short Term Unmetered
- Rental and Customer-owned Facility Rates
- Open Access Transmission Tariff

The majority of electricity usage is therefore billed[9] under one of the following four broader classes:

- Residential 50%
- General Service 31%
- Small Industrial 7%
- Large Industrial 12%

Tables showing current class structures in use at a sample[10] of other Canadian utilities are provided in Appendix B. Key attributes of the various rate structures are summarized by class in Appendix A.

Some summary comments may help to highlight similarities and differences from this sampling.

With respect to Residential Classes:

- The inclusion of farms varies, but most utilities allow some small "business" load in this class, which could allow smaller farms in some cases. Farms are explicitly stipulated as being included in the residential class at MECL, NB Power and Hydro Quebec. Specific farm rates are however provided at SaskPower, Fortis Alberta and BC Hydro. Specific seasonal agricultural irrigation rates are available in Sask, Alta and BC.

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[8] Percentages are rounded. The load associated with the smallest classes represents less than 1% and therefore does not show in the figures.

[9] Per 2019 data provided by MECL

[10] The sample is not intended to be a complete representation of all utilities in Canada. Instead, it is a sampling of utilities which have some similarity to MECL with respect to considerations such as function, ownership, agricultural base, and regulatory environment. The mosaic of utility structures across Canada with varying degrees of deregulation and unbundling of services makes direct comparison difficult. Rate class definitions, inclusions and demand/energy eligibility also vary.

- About half of sampled utilities have a residential urban/rural rate distinction.

With respect to the General Service Classes:

- Only MECL and NB Power utilize only one class for all General Service customers, regardless of size or other defining characteristics
- Most utilities subdivide General Service customers into smaller classes based on demand requirements. NS Power defines the Small General Service class on the basis of annual energy requirement. There are a wide variety of thresholds used to define subclasses.
- SaskPower offers urban and rural general service rates.

With respect to the Industrial Classes:

- Several of the sampled utilities do not offer a class specific to industrial customers. Of those that do, there is often no particular distinction by customer size.
- Only MECL, NS Power and NB Power offer a Small Industrial class. Small industrial customers at the other utilities are included with medium sized customers. NS Power's small industrial is offered to smaller sized customers than NB Power's or MECL's. Farms are included in the Small Industrial class at NS Power. Some farming load measured using a separate meter is included in the Small Industrial class at MECL, while some associated farming load; e.g. a potato storage warehouse, measured using a separate meter, is included in General Service at MECL.
- NS Power's tariffs include a medium industrial class, while most of the sampled utilities do not. MECL and NB Power include such customers in their Large Industrial classes.

Overall, there is no "standard" regarding the set of customer classes employed across utilities. While the broad categories of residential, industrial and general service (or "commercial") are usually represented, further division of customer groups is often a function of the size and diversity of the customer base in a particular jurisdiction.

From a cost of service ratemaking perspective, the assessment as to which customer groups or classes should be employed is best determined through a CAS analysis of consumption and cost causation differences among potential subgroups. This can be assisted by the availability and analysis of load research, or interval metered data histories for samples of customer groups.

Maritime Electric Rate Class Definition and Availability

Residential Class:

MECL offers separate rates for urban and rural residential customers. It also offers a seasonal residential rate and a seasonal meter reading and billing option.

The class is defined in the Rate Application Guidelines as being available to customers who use electricity for living purposes in any of the following:

"Dwellings;

Dwelling out buildings; and

Individually metered, self contained dwelling units within an apartment building.

In addition, the Residential Rate applies to:

Services to farms and churches; and

Service for the construction phase of a dwelling.

A premises providing lodging with nine (9) beds or less, including boarding and rooming houses, special care establishments, senior citizen homes, nursing homes, hostels and transition homes.

The combined usage of a dwelling and a business operation measured by one meter, where the connected load of the business operation, excluding space heating and air conditioning, is two (2) kilowatts or less.

Seasonal

Customers who use electricity for living purposes in a dwelling other than the customer's principal residence; e.g., summer cottage."

General Service Class**:**

MECL offers a General Service class with a Seasonal Operators optional category. Availability is defined as being:

"That category of customers in all areas served by Maritime Electric who use electricity for purposes other than those specifically covered under Residential, Small and Large Industrial, Street Lighting or Unmetered Categories.

General Service seasonal operators with fully accessible outside meters may remain connected year round provided that the energy used during the period 1 November to 31 May inclusive does not exceed fifty percent (50%) of the total energy used between 1 June and 31 October of the preceding year. General Service seasonal operators whose 1 November to 31 May consumption exceeds this fifty percent (50%) shall be billed under the applicable General Service rate for the periods connected. Meters shall be read or estimated and bills shall be rendered for May, June, July, August, September and October."

The Rate Application Guidelines stipulate:

"General Service rate applications include the following:

Religious and charitable institutions, excluding churches;

Service for the construction phase of any premises other than a dwelling;

Dwellings providing lodging with more than nine (9) beds, including boarding and rooming houses, special care establishments, senior citizen homes, nursing homes, hostels and transition homes;

Combined usage of a dwelling and a business operation measured by one meter, where the connected load of the business operation, excluding space heating and air conditioning, is greater than two (2) kilowatts;

Bulk metered apartment buildings that combine the service to the dwelling units and/or the common use areas;

Service to common areas in apartment buildings;

Any business operation involving both manufacturing/processing and service/repair on which less than one half of the business volume is manufacturing/processing;

Warehousing, storage and distribution centres on the same property and forming part of a manufacturing or processing operation with one meter where the warehousing, storage and distribution load is greater than one half of the total electricity consumed;

A retail or wholesale operation on a farm must install a separate meter to measure that retail/wholesale load;

Water pumping, sewage lift stations, sewage lagoons, chlorinating plants and sewage treatment plants directly related to municipally owned water supplies or waste disposal systems are normally billed at General Service Rates. At the option of the customer, an Industrial Service Rate may be applied; and

General Service seasonal operators with fully accessible outside meters may remain connected year round provided that the energy used during the period 1 November to 31 May inclusive does not exceed fifty percent (50%) of the total energy used between 1 June and 31 October of the preceding year. Examples of eligible facilities include seasonal tourist accommodations, attractions or eateries."

Small Industrial Class:

This class is defined as that category of customers who use electricity chiefly for manufacturing or processing of goods or for the extraction of raw materials and have a minimum contracted demand of five (5) kilowatts.

The Rate Application Guidelines stipulate:

"Industrial Rates apply to the following S.I.C. groups:

Division C Major group:

04 Logging Industry

Division D Major groups:

06 Mining Industries

07 Crude Petroleum and Natural Gas Industries

08 Quarry and Sand Pit Industries

09 Service Industries Incidental to Mineral Extraction

Division E Manufacturing Industries.

In addition:

Fish hatcheries qualify for this rate.

Any business operation involving both manufacturing/processing and service/repair in which more than one half of the business volume is manufacturing/processing.

Warehousing, storage and distribution centres on the same property and forming part of a manufacturing or processing operation with one (1) meter where the manufacturing/processing load is greater than one half of the total electricity consumed.

A processing operation on a farm must install a separate meter to measure that processing load.

Customers whose demand is above 750 kW and less than 3000 kW may choose to be billed at the Small Industrial Rate but must meet certain conditions of the Large Industrial Rate; specifically, they must be metered at a primary voltage of 69 kV and own the step-down transformation from the primary service voltage or pay an equivalent rental charge."

Large Industrial Class:

This class is defined as that category of customers in all areas served by Maritime Electric who use electricity chiefly for manufacturing or processing of goods or for the extraction of raw materials and have a minimum contracted demand of 750 kW.

The Rate Application Guidelines stipulate:

"Industrial Rates apply to the following S.I.C. groups:

Division C Major group:

04 Logging Industry

Division D Major groups:

06 Mining Industries

07 Crude Petroleum and Natural Gas Industries

08 Quarry and Sand Pit Industries

09 Service Industries Incidental to Mineral Extraction

Division E Manufacturing Industries.

In addition:

Any business operation involving both manufacturing/processing and service/repair in which more than one half of the business volume is manufacturing/processing.

Warehousing, storage and distribution centres on the same property and forming part of a manufacturing or processing operation with one (1) meter where the manufacturing/processing load is greater than one half of the total load.

Customers whose demand is above 750 kW and less than 3000 kW may choose to be billed at the Small Industrial Rate but must meet certain conditions of the Large Industrial Rate; specifically, they must be metered at a primary voltage of 69 kV and own the step-down transformation from the primary service voltage or pay an equivalent rental charge."

Observations:

MECL's set of rate classes are not unusual from those in general use. There are however some changes to the current rate class structure that I recommend or recommend be considered as further information is available.

Residential

About half of the sampled Canadian utilities have separate customer charges for urban and rural customers however their service territories are often much more extensive than MECL's and there may well be larger cost differences in service in those jurisdictions. In its November 2018 GRA, MECL proposed to eliminate the urban/rural distinction regarding the residential Service Charge[11], stating that:

"With changes in meter reading technology and increases in customer density throughout PEI, the cost differential between these groups is no longer considered material. As a result, the Company believes it is no longer appropriate to segregate the Urban and Rural customer groups within the Residential rate class and, therefore, proposes that they be combined as one group with the same monthly service charge."

I agree with MECL's reasoning for merging the groups into one and recommend IRAC approval. MECL has proposed a single Service Charge and that the charge be set at the current Urban Service Charge level since it closely represents the customer costs as determined in the Cost Allocation Study. For future rate

[11] MECL November 2018 GRA, pages 128-129

making this single charge should be set to recover the customer costs of the combined group. The energy charges for the two groups are already identical.

MECL currently offers a seasonal residential rate (rate code 131) which is designed to serve residential load that is not used year-round. The rate offered is currently identical to the rural residential rate which has been recommended to be merged with the urban rate to form one customer group. Accordingly, I believe that the seasonal customer group should also be merged with urban and rural.

MECL has also offered seasonal customers an optional separate Service Charge based on reduced meter reading and billing costs (Residential Seasonal Option, rate code 133). New meter reading and billing technology and procedures may have reduced the costs upon which this option was originally premised, and as a result, there may be no direct cost basis to continue the option. The seasonal billing option may provide sufficient customer convenience to remain available.

Farms

Farming load is handled in a variety of ways. Some utilities include all farm load in the residential class, some just a portion, and some none at all. Some offer a separate rate class for farms[12], while others include farms in their General Service or Industrial rate classes.

MECL's residential class includes most farms in PEI. There is no right or wrong answer; the goal is to charge them fair and equitable rates such that they recover their costs within the approved range of R/C ratios.

MECL have stated that they believe smaller family-owned farms should remain on the residential rate[13], citing the following reasons:

- "More than half of the 2,200 Residential Rate accounts identified as farms have no second block energy usage, so they will not be affected by the elimination of the second block energy charge.
- It will help to support the tradition of the family farm in PEI. It appears that there is a growing interest in organic farming practices, in some cases on a small scale.
- It would be consistent with one of the provisions of the existing Residential Rate, under which a Residential Rate customer may operate a business from their home, provided that the electricity usage for the business does not exceed half of the total usage."

I support their recommendation in this regard. The inclusion of large farms in the residential class could however skew residential class characteristics and costs versus more typical residential load and this inclusion should be reviewed. This issue is tied to the concerns that have been expressed about the declining second block of the residential rate, which many large farms utilize. The residential class as a whole, and energy taken under the second block rate in particular, have R/C ratios below the range required to avoid cross subsidization between customer groups and classes. As a result, there is a need to eliminate the second block, which will result in increases to large residential consumers and large farms.

While SIC (Standard Industrial Classification) code records are perhaps somewhat inaccurate or incomplete, there are approximately 2200 MECL residential class customers (large and small) with

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[12] Of the utilities sampled for this study, SaskPower, Fortis Alberta, and BC Hydro utilize a separate class for farms

[13] MECL Farm Study, section 6

attached farming SIC codes[14], with about 2000-2100 served year-round[15]. In winter (February for example), about 1400 of these farms do not require more than first block energy and in summer (July for example) 1700 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. However in 2017, 28.8 GWh[16] of second block energy was purchased by large farm residential customers, representing 55% of total energy and 45% of revenue received for this subgroup of the class. Table 13-10 of MECL's November 2018 GRA indicates that there were 635 farm customers purchasing second block energy in February 2017, and 280 in July 2017.

Table 1-1 of MECL's Farm Study indicates that large farm customers would have seen an average increase of 17% by moving to a single block residential rate which produced the same overall residential energy revenue at 13.53 cents/kWh.

As part of its study to analyze farm load, in 2018 MECL installed interval metering at a sample of 87 farm sites across the province and has been collecting data since. The sample comprises 50 potato farms, 30 dairy farms, 3 hog farms and 4 poultry farms. MECL's initial review indicates that the cost of serving farm load exceeds that of typical residential load. As a result, the inclusion of large farm load in the residential class, particularly with the use of a declining block energy rate, means that farms are not paying their cost of supply.

Grouping large farm load with more typical domestic-use equipment, consumption and behaviour can introduce intra-class inequities and distort rates.

Options regarding large farms include leaving them in the residential class, moving them out of Residential Class and into their own class, the General Service Class or the Small Industrial Class. Migration does not resolve the issue of the residential second block rate for larger non-farm residential customers but may facilitate setting rates for large farm customers which most closely matches their cost of service. It also separates large farm load from large residential load which likely recognizes and addresses cost causation differences.

Options

1. Leave all large farm customers in the Residential class and manage the elimination of lower cost second block rate. If this is the case, I support the Multeese Consulting approach of a three year phased in increase in the second block rate to facilitate its ultimate elimination.
2. Create a new rate class for large farm customers. As a class, they represented $8.37 million in cost[17] in 2017. The revenue they provided under the Residential tariff was $6.87 million, resulting in a R/C ratio of 0.82. In order to increase this R/C ratio to the target of 0.95, an increase of 15.8% would be required. This would create a fairly small but functionally homogenous rate class[18], provide a rate that closely matches the costs of serving the group, and facilitate the potential design of targeted rate mechanisms which could help farms manage their

[14] MECL Farm Rate Study.
[15] MECL GRA filing, November 2018. Schedule 13-10.
[16] Table 3-2, MECL Farm Rate Study
[17] 2017 Chymko CAS, Appendix A, Schedule 1.0
[18] While small, the new Farm Class would not be much smaller than the current Small Industrial class with revenues of approximately $12 million

costs and provide system benefits[19]. Note however, that creating a separate and small class can potentially become problematic if other customer groups seek the same.

3. Migrate large farm load to the General Service class. The GS class is intended for customers who do not fall into categories included in other rates however, and this class is quite large and diverse in nature. It also has a 2017 R/C ratio of between 113% and 122% (seasonal and year-round), which is well above the target of 105% maximum. Adding significantly more load and cost[20] to this class is not recommended. In fact it is recommended that MECL look closely at the GS with respect to separating it into two or three new classes which may better reflect costs and revenues for each.
4. Migrate large farm load to the Small Industrial class. The small industrial rate has a 2017 R/C ratio of 102%, well inside the 95-105 target range. MECL's small industrial class definition does not currently include farming load, however there is precedent for this in Nova Scotia. NSPI's small industrial tariff does explicitly include farms. Table 4-2 of MECL's Farm Rate Study estimates that per unit costs for the sampled farms approximates, but are slightly less than the small industrial rate components. A wholesale migration to the Small Industrial would result in increases to farm customers between 20 and 25%, but if, as MECL proposes in its Farm Rate Study, these customers were given the option to self-select the Residential single-block tariff or the Small Industrial, rate increases would generally fall between 10 and 20% depending on the customer's load factor.

Recommendation

I believe there is merit in separating large farm load from residential load. The equipment in use and behavioural characteristics of electricity use are likely dissimilar and both customer groups may benefit from separating cost causation drivers.

While creating a separate rate class for large farms might provide the most accurate cost estimate for rate making for the group, the number of customers and size of the load would be quite small and class cost estimation could be affected by a few large customers.

MECL has estimated that the unit costs of serving large farm customers are close to the unit costs of serving small industrial customers. Adding large farm customers to this class is likely more efficient and manageable than creating a new and very small class. In addition, a demand charge is an appropriate price signal for this load, and rate mechanisms which may be offered to industrial customers to assist in their load and cost management will also then be available to large farms which may be able to take advantage of them.

I support MECL's recommendation that large farm customers move to the small industrial class. I also support their recommendation that migration be voluntary since electricity cost under each tariff depends on the customer's load factor and as such self-defines which rate is appropriate. I recommend that these customers migrate coincident with changes to the second block residential and that their annual increases during transition be limited to less than 5%.

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[19] For example, as suggested by MECL in its Farm Study, a time-of-use rate to reduce demand during peak times

[20] Adding farm customers would increase the costs allocated to the class by $8.3 million, which is approximately 17% of the current GS class costs. Reference MECL GRA filing, November 2018, Schedule 13-6.

General Service Class

At most utilities, General Service classes are used for customers who do not fall into the other defined classes available. As a result, although the majority of General Service customers are commercial in nature, their mix can be eclectic, comprising a variety of business types, electric use patterns and volumes. Some utilities have one large class, while others separate the class into subgroups based on commonalities.

Most sampled Canadian utilities have at least two levels of general service classes. The subdivision is usually based on demand requirements or service voltage, but NSPI's Small General class is based on annual energy requirement. The only sampled utility that separates urban and rural general service customers is SaskPower. MECL and NB Power have a single General Service class which applies to any customers who are not included in the other classes.

The single General Service class used by MECL could mean that some subgroups may be subsidizing others within the class. I recommend that MECL continue to gather data for cost allocation review and analysis with the potential for separating the class into smaller, perhaps more homogeneous classes. Separate classes might also facilitate the development and implementation of targeted rate mechanisms which can assist customer groups in managing their electric use and cost.This is discussed in a later section of this report.

Industrial Classes

Industrial customers are often defined as material extractors, processors and manufacturers, sometimes referencing particular SIC codes (as is the case with MECL). General Service customers, as discussed above, are usually not defined as such and are a default class for customers who do not fit the definitions of other classes. The drivers underlying the establishment and operation of industrial businesses can be different than commercial or "general" businesses and therefore it is useful to forecast their demand and revenue separately. Industrial rates are sometimes used as an economic growth tool, attracting/retaining industry and employment. Industrial processes often share common equipment types such as motor load and sometimes have more behaviourally flexible load than commercial customer loads which tend to be more must-run in nature, such as AC, refrigeration and lighting.

Having separate industrial rates allows for more targeted price/cost relationships and possibility of load management tools[21] which result in savings for them as well as system benefits for all customers.

Industrial rate structures vary from one jurisdiction to another, depending upon the industrial and economic base in the area. In my opinion, the current industrial rate structure (i.e; the classes and rate structures offered) is appropriate for Prince Edward Island.

Rate Structure Mechanisms and Components

Electric rates are designed on a prospective basis. That is, the customer power requirements are forecast (load forecast), the costs of supplying those power requirements (revenue requirement) are forecast, and

[21] For example, critical peak pricing or interruptible credits

the customer class billing determinants (e.g.; energy consumed, demand requirements) are forecast. Using these forecasts and the rate structure, rates (e.g.; cents per kWh of energy consumed) are set by rate class to provide the total revenue requirement forecast and class revenues which are intended to closely match the costs forecast by class. If R/C ratios will remain within the approved range, rates may be adjusted on an "across the board" basis, applying similar increases to each class. If not, the adjustments by class will be different, and care must be taken to manage the size of increases proposed by class.

Costs determined using a Cost Allocation approach are referred to as Embedded Costs. They represent the average costs of providing electricity over a forecast year.

The main considerations of rate structure design relate to the efficient and effective collection of revenue which match allocated costs. There are broad categories of cost which vary according to different factors. There are fixed and variable costs; large, intermittent costs such as generation asset additions, variable costs that vary based on the number of customers or sites served (customer-related), or costs that vary with the amount of energy consumed (energy-related) or point-in-time demand requirements (demand-related).

There are often reasons why a utility might want to signal and/or incent its customers to manage their electricity consumption in certain ways or during certain time periods so that costs to all customers can best be managed and kept as low as possible. Some rate mechanisms send these signals through component pricing. While there are a variety of rate mechanisms which can be employed, the overall goal is to collect fixed, customer, energy and demand costs from each customer class.

No rate study would be complete without including the time-honoured principles of good rate design published in Dr. James C. Bonbright's (Columbia School of Business) 1961 book, Principles of Public Utility Rates ("Bonbright's Principles").

They are:

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

These Principles continue to provide excellent guidance for ratemaking. However, it should be kept in mind that both cost of service and rate design are not exact sciences, but there are parameters guiding discussion. Cost of Service is calculated in a robust and accepted framework and principles of good tariff design reflect the societal goals from multiple perspectives with cost-causation as a common thread.

Customer Charges

Costs relating to service lines, metering, meter reading, billing, remittance & collection, uncollectibles & damage claims are all classified as site related. It is generally recognized that the cost of these functions will primarily vary with the number of customers served. Also, a portion of distribution transformer costs and distribution line costs are generally recognized as being a function of the number of customers served, and are classified as site related. These customer-related costs are most often recovered from smaller consumers via customer charges, usually set as a $/customer/billing period.

Since customer costs are the utility's site-related costs of providing electricity to an individual customer, including metering, meter reading and billing costs among others, it is important that the utility be provided regular and ongoing revenue to provide this cost recovery. These are costs which don't vary with the customer's demand or energy consumption. So rates that do not include a fixed component such as a customer charge, or that do not have a customer charge sufficient to recover these customer costs in full, risk under recovery for the utility. This can also be the case with net metering rates which can, if so structured, return a portion of customer cost revenue along with the reduced energy costs associated with customer self-generation. The loss of customer-related cost recovery for a growing number of net metering customers could become a financial concern for the utility. Removing customer costs from the amount credited to net metering customers recognizes the ongoing requirement for these customers to remain connected to the grid and the associated costs to the utility and its other customers.

Energy rates

Power supply costs are classified in the CAS as either demand-related or energy-related depending upon what the variable cost drivers are. Energy-related costs vary with the amount of energy consumed and are generally recovered through rates expressed in cents/kWh.

A "flat energy rate" denotes that all energy consumed in the billing period is billed at the same rate. Some utilities employ more than one rate and apply the rates to defined incremental energy "blocks" consumed during the billing period. If the incremental block rates are progressively more expensive with increasing consumption, it is known as an "inclining block" structure. If the block rates are progressively declining, it is known as a "declining block" structure. Generally, inclining block rates are expected to discourage or dampen increasing consumption while declining block rates are expected to facilitate or encourage increased consumption. Inclining block structures are set to recognize utility energy supply costs which increase as consumption increases, or may be set for societal reasons to encourage energy conservation. In some cases, block rates may be designed to recover average energy costs in the first block and marginal energy costs in a subsequent block.

Utilities have experimented with promoting energy conservation through the use of inclining block rates (IBR) for many years, particularly in California. While intuitively one may expect increasing prices for energy blocks will dramatically dampen consumption, studies have indicated that while this can happen, this is not always the case. There are many factors which affect customers' choices of end-use equipment and their usage of this equipment. While some studies indicate energy conservation results, others are less certain of the effect that inclining block rates have had. In the synopsis of his experience in studies indicating both results, Dr. Ahmad Faruqui of The Brattle Group states[22], "Thus there is no general rule which says that IBRs will promote energy conservation, or that "de-inclining" IBRs (e.g., flattening the existing rate blocks) will lead to loss of conservation.". The impacts of such rates vary for a number of factors which likely vary by region, economic conditions, consumer culture, end-use mix and utility rates.

Demand Charges

While energy consumption is a measure of power used over a period of time, demand is the power required during a very short time interval. Utility assets and operations are planned around energy requirements and also the accumulated peak demand over the planning period. While there may be sufficient generation available to generally provide energy needs over time, utilities must also prepare to have sufficient resources available to meet the peak demand needs, or have mechanisms in place to manage the peak demand on the system.

The customer's demand could be measured to be coincident with the distribution system peak, be based on the individual customer's maximum demand regardless of time of occurrence, or it could be based on a combination of the two to best recognize cost causation.

These considerations are addressed using price signals conveyed through the demand charge component of rates. This is a way of explicitly recognizing demand-related cost causation and recovery. Demand charges incent customers to consider their electric demand. Since the use of demand charges requires that special meters be used to capture demand as well as energy usage, they have generally been utilized for larger customers whose demand is significant enough to measure and impact the system. Residential and Small General customers do not usually have demand charges as a rate component but they do still contribute to demand-related costs through other components in their rates.

Demand charges are usually expressed as $/kW or $/kW/kWh. The $/kW/kWh approach takes into consideration the relationship between peak demand and energy consumption. This ratio is referred to as load factor. High load factor customers maintain a fairly consistent demand over the billing period, whereas low load factor customers utilize their power more intermittently, with higher demand spikes and lower overall energy usage.

Seasonality

Some utilities vary their rates by season. This may be done to reflect certain changes in the cost of supply by season or to send price signals to encourage or discourage the use of electricity in those seasons. Seasonality in rates is more prevalent with regard to demand charges in order to dampen system peak demands which are of relatively short duration but are expensive to serve.

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[22] The Paradox of Inclining Block Rates, What goes up doesn't always come down. Ahmad Faruqui, Ryan Hledik, and Wade Davis. Fortnightly Magazine - April 2015 https://www.fortnightly.com/fortnightly/2015/04/paradox-inclining-block-rates?authkey=6eb0815f18fd8ea697a9268ee673dc115525cd339a489c7062cb6646ba442f5e

Time of Use Rates (TOU)

Rates can be designed to send time-varying price signals as well. Where the costs of supplying power can vary significantly peak to off-peak, or even from hour to hour, when there is some increased probability or predictability to this variance, time-of-use based rates can be useful. Depending upon the "price elasticity" of the load affected, customers are incented to increase or decrease their consumption based on the varying price. The use of time-varying rates can send effective and efficient price signals upon which customers may choose to modify their consumption behaviour.

These signals are often related to the utility's cost structure and the manner in which its costs of production or delivery may vary reasonably predictably from one period to another. For example, if a utility's production fleet comprises several generation sources such as renewables, hydro, coal, oil and natural gas, the utility dispatches its generation assets in a least-cost manner. This means that typically[23] the lowest cost generation would be employed first, with other generation assets then dispatched in order of increasing cost as needed to serve load. This creates a situation where the hourly load profile is a reasonable predictor of hourly energy cost. If overall resources are limited, or there is opportunity for customers to assist in reducing the overall costs of electricity by modifying when they use electricity for certain end-uses, time-of-use rates are a good method of incenting customers to move their usage from higher cost periods to lower cost periods.

There are various time-based rate mechanisms which seek to achieve load shifting goals, including the use of credits for interrupting demand, critical peak pricing, and end-use-specific time-of-day rates (electric vehicles, for example). It is important to consider customer tools and capabilities however. Mandatory time of use rates introduced without ensuring that customers are able to manage their load can lead to high bills and customer dissatisfaction. Optional TOU provides the rate for those who are best able to take advantage of the price signals while also providing load shifting benefits to the utility. In Nova Scotia for example, TOU rates have only been available to those who utilize electric thermal storage heating systems with time of use controls.

While it is always important for both customers and the utility to efficiently oversee and manage the wise use of electricity, given MECL's contractual annual fixed price arrangements for the supply of power and lack of predictability around unforeseen external variances in its energy or capacity costs, there is no overriding benefit to hourly-varying time-of-use rates at this time. In my opinion, unless there is a somewhat predictable pattern to cost variance, TOU rates themselves would not currently be useful.

This is not to say that there is no potential for time-based rate structures in PEI. The management of annual system peak demand remains an important consideration under the contracts and therefore peak management pricing concepts may be useful in the long term. In addition, the introduction and effects of new electric-intensive technologies such as at-home charging of electric vehicles have the potential to change MECL's system load shape and peak demand. When significant growth in such technologies begins, MECL should consider the adoption of a time of use rate and associated smart metering in order to send price signals to distribute the load and avoid increasing peak demand.

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[23] This approach is adjusted for "must-run" units or "take or pay" power purchase contracts, etc which must be considered when setting dispatch order

Rates Based on Marginal Costs

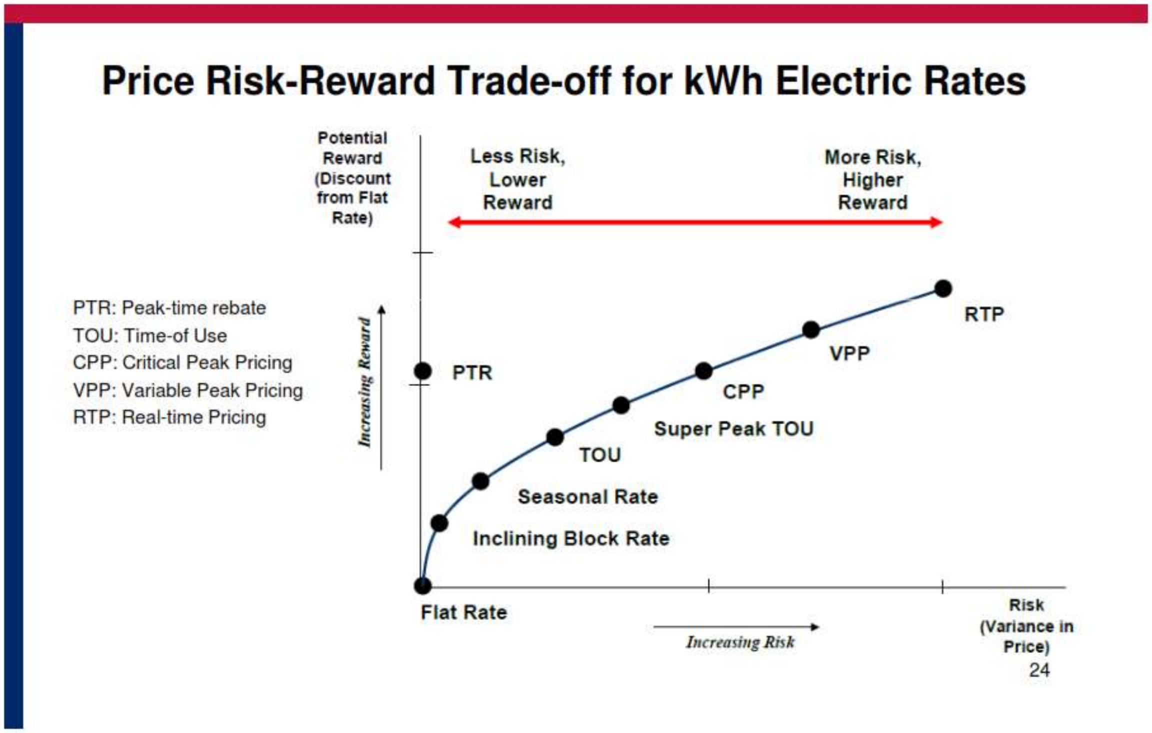
Under cost-of service regulation, utilities strive to recover their embedded costs of service as approved. There are however, other types of cost perspectives which are important to consider when designing rates to incent or discourage certain consumption behaviours.

“Avoided costs” represent the period-specific costs avoided when more expensive production or purchase is made unnecessary through a change in consumption. This is the cost measure often used to determine the amount that should be credited back to participating customers who interrupt at times of system peak.

“Marginal” costs are similar to period-specific avoided costs although they are usually more generically defined as the change in cost per kWh at any given instant in time for a tiny change in load. This represents the cost or value of the kWh that would be added or removed from the system at a given time considering the units or purchases which would be affected. Avoided costs usually represent an averaging or mix of marginal costs over a period of time.

While both avoided and marginal costs are very useful and efficient in sending accurate price signals to customers, there is a mismatch between their period-specific costs and revenue and that calculated from the embedded costs used to set annual Revenue Requirement and Rates. As a result, rates based on marginal costs can be complex and usually need to be adjusted to avoid over or under-recovery of approved embedded costs.

The graphic reproduced below[24] shows the relationship between simple and complex rate designs which require greater customer energy management, and the risk/reward relationship offered to customers.



[24] USAID/NARUC conference presentation by Jason N. Rauch, Ph.D., Maine Public Utilities Commission, March 27, 2014

Rate Structures in Use at Sampled Canadian Utilities

Included in this study is a comparison of contemporary rate structures in use at a sample of other utilities in Canada. The utilities were selected to represent various provinces across the country, and which shared some aspects of MECL's operating environment. The sample was not intended to be all inclusive since there is now a wide range of regulatory and operating environments in Canada.

The rate structure and attributes comparison tables included in Appendices A and B provide overview summaries of the various tariff structures and rates made available at the sampled utilities reviewed. The tables have been prepared specifically to assist in comparing rate classifications and rate mechanisms. As a result, only the relevant classifications and details of the utilities' tariffs are included in the table. Please refer directly to the utilities' tariff documents for full details. While rate levels have been included, the focus is more on the structure than the level of rate charged.

Residential

About half of the sampled utilities use a flat energy rate. MECL has the only declining block residential rate other than the SaskPower farm rate. Hydro Quebec, BC Hydro and Fortis BC[25] have inclining block structure. Few of the sampled utilities offer seasonally-varying rates or TOU. TOU rates are optionally available at NS Power coupled with the use of thermal storage heating systems with automated control. Hydro Quebec offers some seasonality and critical peak pricing (CPP) in this class.

General Service

There are a variety of definitions and eligibility requirements for general service class customers. Some utilities have several General Service classes, others have one. Most sampled utilities include a Service Charge for small and medium sized customer groups but less so for larger customers. About half utilize a demand charge for general service customers. Most employ declining block energy charges but block size varies due to diversity of class definition and customer size. BC Hydro and Fortis BC have flat energy charges. NL power offers seasonal demand charges and Hydro Quebec offers seasonal energy charges and critical peak pricing. Fortis Alberta has a three tier declining $/kW demand mechanism which may serve as a proxy for a Service Charge. TOU rate structures are not common among the sampled utilities for this class of customer however Hydro Quebec offers an Interruptible credit and Fortis BC has on/off peak pricing for large general service customers.

Industrial

Many of the sampled utilities do not differentiate industrial rates by customer size. Observations provided here relate to those that do.

Small Industrial

This class is only offered at NS Power, MECL and NB Power. The NS Power class is for smaller sized customers than MECL or NB Power. Farms are included in this class at NS Power, and farming load on a separate meter is currently included in this class at MECL. The tariffs here do not utilize an explicit Service

[25] Though this is being phased out.

Charge but do employ $/kW or $/kVA demand charges. Energy charges are declining block cents/kWh where the first block is essentially a proxy Service Charge.

Medium Industrial

Of the sampled utilities, only NS Power utilizes a medium industrial class. Other utilities combine customers of this size with larger customers as a class. At NS Power, there is no Service Charge, demand charges in $/kW or $/kVA are employed and energy is charged at a flat rate.

Large Industrial

NS Power, Hydro Quebec, SaskPower and BC Hydro offer large industrial rates. Only SaskPower employs a Service Charge for this class. Others generally collect customer costs, which represent a small portion of the cost of serving large customers, through demand charges. Demand is billed in $/kVA (rather than $/kW used for most other classes) to capture the effects of the customer's power factor.

Flat energy charges are most often employed. Often, specialized rates are available for large consumers which have large and discrete loads which can be controlled for use with interruptible or load-modifying rates when available. For example BC Hydro offers pricing where the energy price is lower for energy consumed under the customer's historical baseline load-shape (CBL) than above.

Rate Structure in use by Maritime Electric

Residential Class

Residential Urban

That category of residential customers located in all incorporated cities, towns and villages with population over 2000 served by Maritime Electric.

Rate (Code 110)

Service Charge:	$24.57 per Billing Period
Energy Charge:	14.37¢ per kWh for first 2000 kWh per Billing Period 11.42¢ per kWh for balance kWh per Billing Period

Residential Rural

That category of residential customers located in all other areas not included under Residential Urban category served by Maritime Electric.

Rate (Code 130)

Service Charge:	$26.92 per Billing Period
Energy Charge:	14.37¢ per kWh for first 2000 kWh per Billing Period 11.42¢ per kWh for balance kWh per Billing Period

Residential Seasonal

That category of Residential Customers who require service to a dwelling other than a principal residence (e.g., summer cottages).

<u>*Rate (Code 131)*</u>

Service Charge:	\$26.92 per Billing Period
Energy Charge:	14.37¢ per kWh for first 2000 kWh per Billing Period 11.42¢ per kWh for balance kWh per Billing Period

Residential Seasonal Option

Residential seasonal customers with fully accessible outside meters may remain connected year round provided that the energy used during the period 1 November to 31 May inclusive does not exceed fifty percent (50%) of the total energy used between 1 June and 31 October of the preceding year. Residential Seasonal customers whose 1 November to 31 May consumption exceeds this fifty percent (50%) shall be billed under the applicable residential service rate for the periods connected. Meters shall be read or estimated and bills shall be rendered for May, June, July, August, September and October.

<u>*Rate (Code 133)*</u>

Service Charge:	\$37.50 per Billing Period
Energy Charge:	14.37¢ per kWh for first 2000 kWh per Billing Period 11.42¢ per kWh for balance kWh per Billing Period

Discussion of Residential Second Block Rate

My comments and recommendations regarding the inclusion of farms in the class, the amalgamation of Urban and Rural Service Charges, elimination of the Residential Seasonal, and the continuance of the optional Seasonal Billing appear previously in this report in the Rate Classes and Structures section.

The structure of the customer Service Charge in \$/billing period is common and appropriate.

The two block rate however appears uncommon at this point. Utilities have experimented with both inclining and declining block rates to:

1. recover some portion of fixed costs through the use of the first block, charging a lower energy rate for the second block, or
2. encourage conservation through a higher second block rate, or
3. offer block rates which better reflect the utility's energy cost structure as consumption increases, or
4. offer declining block rates to encourage consumption or, within the bounds of regulation, facilitate more competitive rates for specific end uses or customer types

Almost all utilities sampled in this study have a single block rate and some have done so after offering block rates previously. I agree with the Commission, its consultant and MECL that the second block should be phased out and eliminated. It does not provide an appropriate price signal, and is a contributing factor to the lower than required R/C ratio of the class.

The decisions to increase the residential rate and to eliminate the declining second block have essentially already been made. The Commission's Order is clear that unless there is a compelling reason to keep it, the second block should be removed and the Order requires that all rate classes' R/C ratios fall between 0.95 and 1.05. The residential class falls below this and must be increased. The impact on some residential customers will be greater than others due to the use of the declining second block of the residential rate. The question is really how to manage the change on this group of customers. This group is made up of large residential customers and larger farms. I have already provided my recommendation that larger farms be offered the ability to move to the Small Industrial rate.

MECL have stated that they believe smaller family-owned farms should remain on the residential rate[26], citing the following reasons:

- "More than half of the 2,200 Residential Rate accounts identified as farms have no second block energy usage, so they will not be affected by the elimination of the second block energy charge.
- It will help to support the tradition of the family farm in PEI. It appears that there is a growing interest in organic farming practices, in some cases on a small scale.
- It would be consistent with one of the provisions of the existing Residential Rate, under which a Residential Rate customer may operate a business from their home, provided that the electricity usage for the business does not exceed half of the total usage."

I support their recommendation in this regard.

Residential consumers and farms are billed in the Residential Class, which includes a lower priced second block energy charge[27]. This lower block provides electricity at a discount of approximately 21% from the first block charge. Approximately 88% of class load[28] was billed within the first block energy limit of 2000 kWh/month, with the remaining 12% of class energy billed at the second block rate. While this has provided overall lower electricity costs for farms and large residential customers, it has also resulted in an 82% R/C ratio for the farm subgroup[29]. The R/C ratio for the overall Residential Class (including the farm load) is 91%, so there is the dual-increase challenge of bringing costs to farms up to the residential class average level and then increasing the class R/C ratio up to 95%.

If all energy currently billed under the Residential Class had been billed under a single rate for 2017, the energy rate would have been 13.53 cents/kWh in order to return the same annual revenue. Having paid 13.88 cents/kWh for first block energy one could say that first block customers have been subsidizing second block customers who have been paying 10.98 cents/kWh for that portion of their load. Moving all energy to this rate would result in an increase of 23% (2.55 cents/kWh) to second block load, and a decrease of 2.5% (0.35 cents/kWh) to first block load.

Large Residential non-farm

In 2017, 39.1 GWh[30] of second block energy was purchased by non-farm residential customers, representing 7.7% of total energy and 5% of the revenue received for this subgroup of the class. Customers consuming more than 2000 kWh/month will for the most part be larger homes and/or utilize

[26] MECL Farm Study, section 6

[27] Based on calendar year 2017, the average first block energy charge was 13.88 cents/kWh and the second block average energy charge was 10.98 cents/kWh.

[28] Based on 2017 billing data

[29] As calculated in the 2017 CAS. The estimate based on the first year of interval metered data for the farm sample indicates 86% R/C ratio.

[30] Table 3-2, MECL Farm Rate Study

electricity for heating/cooling. Phase-out and elimination of the lower priced second block rate will increase their costs but for a relatively small portion of their load.

Two examples of how to phase out the second block have already been suggested.

In their November 2018 GRA filing, MECL proposed to maintain the second block definition and rate until March 2021, at which time the first block definition would be modified to encompass load up to 5000 kWh/month, and to eliminate the second block entirely in March 2022.

Multeese Consulting, IRAC's consultant is not supportive of this approach, and proposes to increase the second block rate in increments over a three year period, until it is equivalent to the first block, at which time the second block would be eliminated[31].

The Multeese approach is similar to the approach requested by FortisBC in 2018[32] where that utility sought approval to phase out the existing inclining second block of its residential tariff by adjusting it gradually over a five year period. This was approved by the BCUC in 2019[33].

The impact of the MECL-proposed and Multeese-proposed approaches upon customers is different. While the timing of rate changes may need to be adjusted as time marches on pinching previously set target dates, I support the price change approach with immediate start, and longer phase out period. This is the approach put forward by Multeese Consulting. This provides clear signals that second block pricing itself is increasing and will be phased out on a schedule rather than continuing the discount on a specific portion of load.

Continued load research analysis in this class could assist in developing further rate design adjustments as cost causation factors and load shapes are better understood.

General Service Class

General Service

That category of customers in all areas served by Maritime Electric who use electricity for purposes other than those specifically covered under Residential, Small and Large Industrial, Street Lighting or Unmetered Categories.

Billing Demand

The greater of the maximum kW demand or 90% of the maximum kVA demand in the billing period.

Rate (Code 232):

Service Charge:	$24.57 per Billing Period
Demand Charge:	No charge for first 20 kW or less per Billing Period

[31] Multeese Consulting, Whalen Evidence, page 22, line 15
[32] FortisBC Inc. 2017 Cost of Service Analysis and Rate Design Application, FINAL SUBMISSION, October 17, 2018
[33] BCUC Order G-40-19 | FBC 2017 COSA & RDA Decision

	$13.43 per kW for balance kW per Billing Period
Energy Charge:	17.67¢ per kWh for first 5000 kWh per Billing Period 11.54¢ per kWh for balance kWh per Billing Period

General Service - Seasonal Operators Option

General Service seasonal operators with fully accessible outside meters may remain connected year round provided that the energy used during the period 1 November to 31 May inclusive does not exceed fifty percent (50%) of the total energy used between 1 June and 31 October of the preceding year. General Service seasonal operators whose 1 November to 31 May consumption exceeds this fifty percent (50%) shall be billed under the applicable General Service rate for the periods connected. Meters shall be read or estimated and bills shall be rendered for May, June, July, August, September and October.

Rate (Code 233):

Service Charge:	$24.57 per Billing Period
Demand Charge:	No charge for first 20 kW or less per Billing Period $13.43 per kW for balance kW per Billing Period
Energy Charge:	17.67¢ per kWh for first 5000 kWh per Billing Period 11.54¢ per kWh for balance kWh per Billing Period

The rate components which comprise this tariff are appropriate and generally consistent with other commercial tariffs.

The service charge of $24.57/billing period effectively recovers site-related and demand-related costs up to 20kW of the customer's demand. Based on the component costs presented in Table 12 of the Chymko CAS[34], the customer "site-related" costs for this class are approximately $31/mo for customers billed year-round. From this perspective there is opportunity to increase the customer charge.

The $13.43/kW for demand greater than 20kW is in the range of the demand charges shown in CAC Table 12 ($11.78/kW seasonal and $15.43/kW year-round).

The first block energy charge (17.67 cents/kWh for first 5000 kWh/billing period) is significantly higher than the energy related costs allocated in Schedule 1.1[35] of Appendix A of the CAS. This tends to offset the lower customer charge and to some extent acts as a proxy additional customer charge. The second block rate of 11.54 cents/kWh is also higher than the average energy-related costs shown in CAS Schedule 1.1. The energy charges of this rate should be reduced when changes are made to adjust R/C ratios.

This declining energy block rate structure is similar to those in use for small and medium General Service customers at most of the utilities sampled in this study although the kWh threshold sizes of the blocks vary. While there is no standard demand used as a demand charge threshold that I am aware of across

[34] Included in paragraph 83 of 2017 Chymko MECL Cost Allocation Study, June 26 2018 report.
[35] Page 5 of Appendix A.

utilities, it appears as though the vast majority of MECL's General Service class customers fall below the current 20kW/billing period threshold. Also, given the important seasonal nature of residence and business in PEI, I support the continuation of the seasonal meter reading and billing option.

The levels of each of the tariff's rate components should be designed to recover overall class revenues which closely reflect costs. This is not the case at the present time. For some years, the General Service class R/C ratio has been higher than it should be in order to avoid cross subsidization between classes. This should be corrected.

There may be two aspects to this however.

The first aspect is to bring the existing class R/C into the acceptable range of 95-105. My recommendation is to do so as quickly as possible to reduce their overpayment of costs, but to do so in concert with increases in the residential tariff and migration of large farms to the small industrial rate such that the utility is able to continue to reasonably expect recovery of its revenue requirement during the transition. In his 2019 evidence[36], Mel Whalen, IRAC's consultant proposed general guidelines[37] for making adjustments to class revenues while also considering R/C ratio calibration. I believe these guidelines represent a fair and equitable approach which could also be considered for use in PEI subject to limitations on the size of the percentage changes it would produce.

The second aspect deals with the composition of the class. While the overall revenue from the class needs to be reduced to improve the R/C ratio, the class comprises a wide variety of customer types and sizes. This creates the possibility that some customers are paying too much and some are paying too little, even within the existing class. I recommend that the customer composition of the class be investigated to see if some subgroupings become apparent for CAS purposes. As an example, NS Power's rate structure does provide for small, medium and large General Service classes.

An initial review of MECL's 2017 General Service monthly billing data by energy and demand strata shows that of the approximately 7200 customers in the class[38], about 5200 do not have meters which record demand and are therefore assumed to require less than the 20kW threshold for demand charges. Approximately 1000 more have demand meters but generally require less than 20kW, with annualized load factors of less than 40%.

There is a second group of approximately 900 customers with billing demands between 20.1 kW and 250 kW. Their annualized load factors are generally between 40 and 50%.

And finally, there is a group of approximately 35 large customers in this class whose billing demand exceeds 250kW and whose annualized load factors average about 60%.

As shown in Table D-1 and D-2 of Appendix D, these groups, or groups defined using a similar approach could represent potential new levels of General Service classes, depending upon their consumption profiles and costs of service. Table D-1 is based on a review of demand strata and Table D-2 is based on energy strata. Each provides similar numbers of customers in the potential subclasses.

[36] MECL GRA Nov 2018, Direct Evidence of Mel Whalen, P.Eng., May 23, 2019, page 21.

[37] These guidelines are similar to those used by the Nova Scotia Utilities and Review Board in 2002

[38] I report these figures as approximate because the dataset utilized was monthly and listed by demand and energy stratum, so the number of customers in a particular stratum varied by month.

Different customer groups can have quite different cost allocators depending upon determinants such as coincident and non-coincident peaks, service voltage, etc. The groups highlighted in Appendix D are examples of three groups which, with perhaps with more load research information and costing analysis within the CAS may be candidates for separate general service classes. I recommend this if CAS analysis shows they are sufficiently distinct and that doing so improves the cost allocation and recovery accuracy.

Small Industrial Class

Small Industrial

That category of customers who use electricity chiefly for manufacturing or processing of goods or for the extraction of raw materials and have a minimum contracted demand of five (5) kilowatts.

Billing Demand: The greatest of:

- The monthly maximum kW demand;
- 90% of the monthly maximum kVA demand; or
- 5 kW.

As a result of installed metering, both the monthly maximum kW demand and 90% of the monthly maximum kVA demand noted above may not apply.

Rate (Code 320):

Demand Charge:	$7.46 per kW of billing demand per month
Energy Charge:	17.31¢ per kWh for first 100 kWh per kW of billing demand per month 8.72¢ per kWh for balance of kWh per month

To be eligible for service with a contracted demand, customers must sign the Contract for Electrical Service under Section C - Agreements and Forms.

The rate components which comprise this tariff are appropriate and generally consistent with other industrial tariffs.

The demand charge is less than the $12.14/kW shown in Schedule 1.1 of CAS Appendix A[39], however the charge is applied using a minimum billing demand of 5kW so may recover sufficient demand cost recovery overall. The first block energy charge, which appropriately recognizes the customer's load factor, is set at a rate much higher than the allocated energy costs from Schedule 1.1 of CAS Appendix A and serves to also assist in collecting both customer and demand costs. The second block energy rate is set very near the allocated energy costs shown in Schedule 1.1 of the CAS Appendix A.

In general, demand costs are recovered through the demand charge which is applied to a minimum contract 5kW billing demand, and from higher actual metered demand. The declining block energy rate

[39] Page 4 of Chymko CAS Appendix A.

(with the first block dependent upon billing demand, kWh/kW) is similar to those used at NS Power and NB Power. This mechanism is designed to recognize customer load factor through an energy charge.

MECL, in its Farm Rate Study, has recommended that larger farms currently included in the Residential class be offered the Small Industrial Rate as an alternative to a revised Residential rate which has a single energy charge. As stated earlier in this report, I support this recommendation. Once MECL has assessed which customers would move and which would stay, the costing and rate setting procedure should include their load in the Small Industrial class in the next CAS.

Large Industrial Class

Large Industrial

That category of customers in all areas served by Maritime Electric who use electricity chiefly for manufacturing or processing of goods or for the extraction of raw materials and have a minimum contracted demand of 750 kW.

Billing Demand: The greatest of:

- The monthly maximum kW demand;
- 90% of the maximum kVA demand;
- 90% of the firm amount reserved in the contract for non-curtailable customers or 100% of the total contracted amount for curtailable customers;
- 90% of the maximum demand recorded during the current calendar year excluding April through November; or
- 90% of the lesser of the average demand recorded during the previous calendar year, or the previous calendar year excluding April through November.

Rates (Code 310):

Demand Charge:	$14.50 per kW of the billing demand per month
Energy Charge:	7.14¢ per kWh for all kWh per month

Rental Charges

- Primary distribution voltage to customer's utilization voltage

At the Customer's request, Maritime Electric will supply, own and maintain the substation equipment at the Customer's premises, including from the primary distribution voltage switches to the low voltage terminals of the step-down transformers, provided such transformation satisfies Maritime Electric Standards. The charge for such rental equipment is 1 5/6% per month of the installed costs. The Customer will supply the low voltage switch gear, concrete substation foundation pads and necessary protective fencing.

Losses Charge

- 69 kV to primary distribution voltage

At the discretion of Maritime Electric, electricity may be supplied at a primary distribution voltage between 4 kV and 25 kV. In such cases, the monthly demand and energy consumption will be increased by 1½% to compensate for transformation losses.

- Primary distribution voltage to Customer's utilization voltage

At the discretion of Maritime Electric, electricity may be supplied at the Customer's utilization voltage. In such cases, the monthly demand and energy consumption will be increased by 1 1/2% to compensate for transformation losses. This charge will be in addition to the losses charge for transformation from 69 kV to the primary distribution voltage.

Transformation Charge

-69 kV to primary distribution voltage

When a Customer is provided service at a primary distribution voltage between 4 kV and 25 kV, the customer will also be charged an "equivalent kVA rental" charge equal to 1 5/6% per month of the costs of the equivalent substation kVA utilized by the Customer's electrical load. The equivalent kVA charge is the Customer's kVA demand multiplied by $1.25 per kVA per month.

Contracts

A Customer supplied at the Large Industrial Rate is required, and is deemed, to have entered a firm contract providing for the payment of the rate, for an initial term of five (5) years, in the case of a Customer considered by Maritime Electric to be a new Customer, and for an initial term of one year for a Customer considered by Maritime Electric to be an existing Customer. The contract will continue thereafter on a firm basis subject to termination by either the Customer or Maritime Electric at the end of the initial term, or any date thereafter by either party giving at least twelve months notice in writing.

Metering

The metering point shall be at or near the transmission line terminals (69 kV).

The rate components which comprise this tariff are appropriate and generally consistent with other industrial tariffs. The manner in which monthly billing demand is determined is somewhat complex however it does provide some continuity of demand billing and significant price signal for customers to manage their peak demand. The demand charge of $14.50/kW is set much higher than the demand-related costs allocated in Schedule 1.1 of CAS Appendix A however this approach is designed to also recover customer-related costs and to send price signals to incent customer demand management. The energy charge in set close to the energy-related costs allocated by the CAS.

Other Maritime Electric Tariffs

This study did not find issues with any of MECL's other tariffs, namely:

Wholesale Rate Schedule

Street and Yard Lighting

Unmetered Rate Schedules

Unmetered Rate Application Guidelines

Miscellaneous Rate Schedules

Short Term Unmetered Rate Schedule

Short Term Unmetered Rate Application Guidelines

Rental Facility Rate Schedules

Customer Facility Rate Schedule

Open Access Transmission Tariff

APPENDICES

APPENDIX A

COMPARISON of

CLASS RATE ATTRIBUTES

At

SAMPLED CANADIAN UTILITIES

Table A-1 RESIDENTIAL CLASS							
Utility	Customer types included	Farms included?	Urban/rural distinction?	Service amp distinction?	Seasonal price variance?	Energy block type	TOU rate available?
NL Power	Domestic use plus business load if <3000W excl SH[40]	"Business load" <3000W excl SH	N	Y	N	Flat	N
NS Power	Domestic, churches, charities[41]	N	N	N	N	Flat	Y[42]
MECL	Domestic, churches and farms	Y[43]	Y	N	N	Declining after first 2000 kWh	N
NB Power	Domestic, churches and farms	Y	Y	N	N	Flat	N
Hydro Quebec	Various Domestic, and farms	Y[44]	N	N	Y	Inclining after first ~1200 kWh	N[45]
Manitoba Hydro			N	Y	N	Flat	N
Sask Power	Domestic	N	Y	N	N	Flat	N
	Farms	Y[46]	N	N	N	Declining after first 16,000 kWh	N
Fortis Alberta	Domestic use plus business load if <1000W	N[47]	N	N	N	Flat	N
BC Hydro	Domestic	N[48]	Y by zone	N	N	Inclining after 675 kWh/mo	N
Fortis BC	Domestic	N	N	N	N	Inclining after 800 kWh/mo	Closed to new entrants

40 Space Heating

41 As permitted within the provisions of Section 73 of the NS Public Utilities Act

42 Use is restricted to customers employing thermal storage systems and TOU controls

43 For both MECL and NB Power, Availability clause stipulates farms, but also states that "The combined usage of a Dwelling and a business operation measured by one meter, where the connected load of the business operation, excluding space heating and air conditioning, is two (2) kilowatts or less".

44 Availability clause stipulates farms, but also states that "When the electricity is not exclusively for habitation purposes, Rate D applies on condition that the installed capacity for purposes other than habitation does not exceed 10 kilowatts".

45 Critical peak rates are available which vary by season, and temperature-dependent rates are available for dual-energy heating customers

46 SaskPower offers specific Farm Rate which includes both domestic and agricultural use. The rate has a demand charge for demand greater than 50kVA. Has a maximum permitted demand of 3,000kVA. In addition, a specific rate is available for Irrigation.

47 FortisAlberta offers a specific farm rate.

48 BC Hydro offers a specific farm rate and an irrigation rate.

Table A-2 SMALL GENERAL SERVICE CLASS						
Utility	Customer Eligibility	Service Charge	Demand Charges	Energy Charges	Seasonal price variance[49]?	TOU rate available?
NL Power	<100kW	Varies by service voltage	Seasonal	Declining block after first 3500kWh	demand	N
NS Power	<32,000 kWh/yr	$/mo	none	Declining block after first 200kWh	N	N
MECL	No distinction by customer demand/energy	See Medium General comparison				
NB Power	No distinction by customer demand/energy	See Medium General comparison				
Hydro Quebec	<65kW	$/mo	$/kW above 50kW	Declining block after first 15,090 kWh	Available	CPP available
Manitoba Hydro	2 levels: A: <50kVA or B: 0-200kVA	Varies by service voltage	A: N B: $/kVA	A: Two block declining after 11,000 kWh B: Three block declining after 11,000 and additional 8500 kWh	Available	N
Sask Power	<75 kVA Urban/Rural distinction	Varies by service transformation	$/kVA varies urban/rural	Declining two block after ~14,000 kWh	N	N
Fortis Alberta	<75kVA	none	Declining block after first 2kW/day	Declining block after first 6.575 kWh/kW/day	N	N
BC Hydro	<35kW	Cents/day	N	Flat energy charge	N	N
Fortis BC	<40kW	$/mo	N	Flat energy charge	N	N

[49] Excluding rate differences for seasonal customers with reduced meter reading & billing

Table A-3 MEDIUM GENERAL SERVICE CLASS						
Utility	Customer Eligibility	Service Charge	Demand Charges	Energy Charges	Seasonal price variance[50]?	TOU rate available?
NL Power	110 – 1000 kVA	$/mo	Seasonal $/kVA	Declining block after first 200 kWh/kW up to 50,000 kWh	demand	N
NS Power	>32,000 kWh/yr	none	$/kW	Declining block after first 200kWh/kW	N	N
MECL	Non res/industrial customers	$/mo	$/kW over 20kW	Declining block after first 5,000	Yes?	N
NB Power	Non res/industrial customers	$/mo	$/kW over 20kW	Declining block after first 5,000	N	N
Hydro Quebec	>50kW	none	$/kW	Declining block after first 210,000 kWh/mo per kW	N	N
Manitoba Hydro	200 -750 kVA	$/mo	$/kVA over 50kVA	Three block declining after 11,000 and additional 8500 kWh	Available	N
Sask Power	75 – 3000 kVA	$/mo varies by urban/rural	$/kVA varies urban/rural	Declining block after ~16,000 kWh. Urban/rural distinction	N	N
Fortis Alberta	<2000 kVA	none	Three tier declining $/kVA plus a peak demand charge	Flat energy charge	N	N
BC Hydro	35-150 kW and <550,000 kWh/year	Cents/day	$/kW	Flat energy charge	N	N
Fortis BC	40 – 500 kW	$/mo	$/kW over 40 kW	Declining block after first 8000 kWh	Available	On/off peak available

[50] Excluding rate differences for seasonal customers with reduced meter reading & billing

Table A-4 LARGE GENERAL SERVICE CLASS						
Utility	Customer Eligibility	Service Charge	Demand Charges	Energy Charges	Seasonal price variance?	TOU rate available?
NL Power	> 1000 kVA	$/mo	Seasonal $/kVA	Declining block after first 75,000 kWh	demand	N
NS Power	>2,000 kVA	none	$/kW current mo or ratcheted prev winter	Flat energy charge	N	N
MECL	No Large General					
NB Power	No Large General					
Hydro Quebec	>5,000 kW	none	$/kW	Flat energy charge	N	N but interruptible credit
Manitoba Hydro	Available at 3 levels of service voltage and demand requirements	$/mo	$/kVA	Flat energy charge	N	N
Sask Power	75 – 3000 kVA	$/mo varies by urban/rural	$/kVA varies urban/rural	Declining block after ~16,000 kWh. Urban/rural distinction	N	N
Fortis Alberta	<2000 kVA	none	Three tier declining $/kVA plus a peak demand charge	Flat energy charge	N	N
BC Hydro	>150 kW and >550,000 kWh/year	Cents/day	$/kW	Flat energy charge	N	N
Fortis BC	>500 kVA	$/mo	$/kVA	Flat energy charge	Y	On/off peak available

Table A-5 SMALL INDUSTRIAL CLASS						
Utility	Customer Eligibility	Service Charge	Demand Charges	Energy Charges	Seasonal price variance?	TOU rate available?
NL Power	No industrial classes at NL Power					
NS Power	< 250 kVA includes farms	none	$/kVA current	Declining block after first 200 kWh/kW-mo	N	N
MECL	5 – 750 kW includes farm load on separate meter	none	$/kW	Declining block after first 100 kWh/kW-mo	N	N
NB Power	5 – 750 kW	none	$/kW	Declining block after first 100 kWh/kW-mo	N	N
Hydro Quebec	No small industrial class offered					
Manitoba Hydro	No small industrial class offered					
Sask Power	No small industrial class offered					
Fortis Alberta	No small industrial class offered					
BC Hydro	No small industrial class offered					
Fortis BC	No small industrial class offered					

Table A-6 MEDIUM INDUSTRIAL CLASS						
Utility	Customer Eligibility	Service Charge	Demand Charges	Energy Charges	Seasonal price variance?	TOU rate available?
NL Power	No industrial classes at NL Power					
NS Power	250 – 2,000 kVA	none	$/kVA current	Flat energy charge	N	N
MECL	>750 kW	none	$/kW	Flat energy charge	N	N
NB Power	>750 kW	none	$/kVA current	Flat energy charge	N	N
Hydro Quebec	No Medium industrial class offered					
Manitoba Hydro	No Medium industrial class offered					
Sask Power	No medium industrial class offered					
Fortis Alberta	No medium industrial class offered					
BC Hydro	No medium industrial class offered					
Fortis BC	No medium industrial class offered					

Table A-7 LARGE INDUSTRIAL CLASS						
Utility	Customer Eligibility	Service Charge	Demand Charges	Energy Charges	Seasonal price variance?	TOU rate available?
NL Power	No industrial classes at NL Power					
NS Power	>2,000 kVA	none	$/kVA current . Interr available	Flat energy charge	N	N
MECL	See Medium Industrial					
NB Power	See Medium Industrial					
Hydro Quebec	>5,000 kVA	none	$/kVA current . Peak day pricing. Interr available	Flat energy charge	N	N
Manitoba Hydro	No industrial classes offered					
Sask Power	>3,000 kVA	$/mo varies by service voltage	$/kVA	Flat energy charge	N	Y
Fortis Alberta	No large industrial class offered					
BC Hydro	Transmission level customers	none	$/kVA	Flat price under CBL, increased price above CBL	Y	CBL-based
Fortis BC	No large industrial class offered					

APPENDIX B

RATE STRUCTURES

At

SAMPLED CANADIAN UTILITIES

Table B-1 NL Power[51]						
Class	Customer type	Customer Chg	Demand Chg	Energy Chg 1	Energy Chg 2	Comments
Residential	(Domestic)	Service Chg $15.97/mo (200A or less service) $20.97/mo (>200A service)		Flat energy charge 12.203¢/kWh		Flat energy charge. Domestic energy uses only[52]. Seasonal available with energy chg adjustments
Small General Rate 2.1	Avail for custs with < 100kW demand	Service Chg $12.13/mo unmetered $20.13/mo single phase $32.13/mo three phase	Demand chg above 10kW: $9.79/kW winter $7.29/kW summer	Energy charge block 12.062 ¢/kWh first 3500kWh	Energy charge block 9.074 ¢/kWh for remainder	Declining energy blocks. Seasonal demand differentiation
General Service Rate 2.3	Avail for custs requiring between 110 and 1000 kVA	Service Chg $49.38/mo	Demand chg: $8.21/kW winter $5.71/kW summer	Energy charge blocks: 10.270 ¢/kWh for first 150 kWh/kW up to 50,000 kWh	Energy charge block 8.292 ¢/kWh for remainder	Declining energy blocks. Seasonal demand differentiation. Curtailable demand credit option
Large General Rate 2.4	Avail for custs requiring > 1,000 kVA	Service Chg $86.05/mo	Demand Chg $7.88/kVA winter $5.38 summer	Energy charge block 9.905 ¢/kWh first 75,000 kWh	Energy charge block 8.211 ¢/kWh for remainder	Declining energy blocks. Seasonal demand differentiation Curtailable demand credit option

[51] As at October 2019. Municipal Tax and Rate Stabilization Adjustments generally apply to all classes. Net Metering Option available to all above classes. No classes specific to "industrial load".

[52] connected load for commercial or non-domestic purposes exceeding 3000 watts, exclusive of space heating, the Service shall not qualify for the Domestic Service Rate.

Table B-2 NS Power[53]						
Class	Customer type	Customer Chg	Demand Chg	Energy Chg 1	Energy Chg 2	Comments
Residential	(Domestic)	Service Chg $10.83/mo		Flat energy charge 15.603¢/kWh		Includes churches and charities. Flat energy charge Additional charges for DSM costs and FAM. Optional Green Rider
Residential TOU	Time of Use (Domestic)	Service Chg $18.82/mo	Winter ¢/kWh : 07:00 am to 12:00 pm 19.961 12:00 pm to 04:00 pm 15.603 04:00 pm to 11:00 pm 19.961 11:00 pm to 07:00 am 8.676	Summer ¢/kWh : 07:00 am to 11:00 pm 15.603 11:00 pm to 07:00 am 8.676	Weekend and Holiday ¢/kWh : All hours at 8.676	Available to customers employing thermal storage systems. Domestic use only Farm load separately classified and metered
Small General	Avail for custs using < 32,000 kWh/year	Service Chg $12.65/mo		Energy charge block 16.285 ¢/kWh for ≤ 200 kWh	Energy charge block 14.471 ¢/kWh for remainder	Declining energy blocks. DSM and FAM applied
General Service	Avail for custs using 32,000 kWh/year or more		Demand Chg $10.497/kW billing demand per month	Energy charge block 12.012 ¢/kWh first 200 kWh/mo per kW maximum demand	Energy charge block 8.733 ¢/kWh for remainder	Declining energy blocks. DSM and FAM applied
Large General	Avail for custs requiring > 2,000 kVA		Demand Chg $13.345/kVA current mo or prev winter ratcheted	Energy charge 9.526 ¢/kWh		Flat energy charge. DSM and FAM applied
Shore Power	Avail Apr-Nov to port authorities to serve cruise ship load >2,000kVA interruptible			Energy charged by voltage level at approved forecast annual marginal energy costs		Tariff designed to facilitate shore-based electricity to visiting cruise ships.

[53] As at April 2019. More specific and detailed tariffs such as the Generation Replacement and Load Following Rate, One-part Real Time Pricing tariffs, Wholesale Backup/Top-up Service, Wholesale Market Non-Dispatchable Supplier Spill Tariff, Shore Power Tariff, Load Retention Tariff, Outdoor Lighting and Unmetered, have not been included in the Table.

				plus fixed cost adder		
Small Industrial	Avail for custs requiring < 250 kVA		Demand Chg \$7.714/kVA	Energy charge block 10.929 ¢/kWh first 200 kWh/mo per kW maximum demand	Energy charge block 8.546 ¢/kWh for remainder	Includes Farming. Declining energy blocks. DSM and FAM applied
Medium Industrial	Avail for custs requiring 250 to 2,000 kVA		Demand Chg \$12.501/kVA	Energy charge block 8.044 ¢/kWh		Flat energy charge. DSM and FAM applied
Large Industrial	Avail for custs requiring >2,000 kVA		Demand Chg \$11.995/kVA current mo or prev winter ratcheted. \$3.43 /mo/kVA reduction in demand charge for billed interruptible demand	Energy charge 8.325¢/kWh for Firm custs 7.976 for Interruptible custs		Flat energy charge. DSM and FAM applied. Reduction in demand and energy charges for interruptibility.
Wholesale (Municipal)			Demand Chg \$12.445/kVA current mo or prev winter ratcheted	Energy charge 8.480¢/kWh		Flat energy charge. DSM and FAM applied

Table B-3 Maritime Electric[54]

Class	Customer type	Customer Chg	Demand Chg	Energy Chg 1	Energy Chg 2	Comments
Residential	Urban	Service Chg $24.57/billing period		Energy charge block 14.37¢/kWh First 2000 kWh	Energy charge block: 11.42 ¢/kWh remainder	Includes farms and churches. Urban/ rural distinction. Applies to Res with bus load > 2kW. Declining energy block.
	Rural or Seasonal	Service Chg $26.92/billing period		Energy charge block 14.37¢/kWh First 2000 kWh	Energy charge block: 11.42 ¢/kWh remainder	
Residential Seasonal	Non principal residences (e.g.; summer cottages)	Service Chg $26.92/billing period		Energy charge block 14.37¢/kWh First 2000 kWh	Energy charge block: 11.42 ¢/kWh remainder	Same as Res Rural rate Declining energy block.
Residential Seasonal Option	Seasonal rate with optional meter reading/billing schedule	Service Chg $37.50/billing period (May-Oct months)		Energy charge block 14.37¢/kWh First 2000 kWh	Energy charge block: 11.42 ¢/kWh remainder	Meters read and bills issued May-Oct. Declining energy block.
General Service	Non-res/industrial/ lighting/ Unmetered, churches	Service Chg $24.57/billing period	Demand Chg $13.43/kW over 20 kW	Energy charge block 17.67 ¢/kWh for ≤ 5000 kWh	Energy charge block 11.54 ¢/kWh for ≥ 5000 kWh	Religious & charitables excl churches. Warehouse & storage if >50% load. Declining energy blocks
General Service Seasonal	Custs with "winter" requirements <50% of summer	Service Chg $24.57/billing period	Demand Chg for demand ≥ 20 kW. $13.43/kW	Energy charge block 17.67 ¢/kWh for ≤ 5000 kWh	Energy charge block 11.54 ¢/kWh for ≥ 5000 kWh	Warehouse & storage if >50% load. Declining energy blocks
Small Industrial	Material processing or manufacturing >5kW <750kW[55]		Demand Chg $7.46/kW	Energy charge block 17.31¢/kWh for first 100 kWh/billing kW	Energy charge block 8.72¢/kWh for excess	Declining energy blocks. ? Minimum of 5kW billing demand. Includes separately metered processing on farm.
Large Industrial	>750kW		Demand Chg: $14.50/kW	Energy charge 7.14¢/kWh		Flat energy charge. Billing Demand is formulaic.[56]

[54] As at October 2019. Rates are inclusive of Energy Cost Adjustment. General, Small Industrial billing demands determined by higher of actual kW demand, or 90% of metered KVA peak. Tariffs for Miscellaneous loads not included in table.

[55] Customers with demand >750kW but less than 3000kW may take service under this rate if they are primary metered at 69kV and own their own distribution transformer.

[56] *Billing Demand:* The greatest of:

- The monthly maximum kW demand;
- 90% of the maximum kVA demand;

			of billing demand			Rate is Costed for 69kV delivery. Load attraction/ expansion, surplus and interruptible options
Wholesale (Municipal)	Long term (10 year) contract option		Demand Chg: $15.51/kW/ mo	Energy charge 9.81¢/kWh		City of Summerside
Wholesale (Municipal)	Short term (1 year) contract option		Demand Chg: $16.79/kW/ mo	First block[57] Energy charge 9.81¢/kWh	All remaining at 8.14¢/kWh	City of Summerside
Unmetered		Min charge $11.67/mo		Energy charge 17.38¢/kWh		8, 12 and 24 hour operating hour rates

- 90% of the firm amount reserved in the contract for non-curtailable customers or 100% of the total contracted amount for curtailable customers;
- 90% of the maximum demand recorded during the current calendar year excluding April through November; or
- 90% of the lesser of the average demand recorded during the previous calendar year, or the previous calendar year excluding April through November.

[57] First block energy defined as minimum monthly energy required by customer from previous year under normalized customer generation conditions.

Table B-4 NB Power[58]						
Class	Customer type	Customer Chg	Demand Chg	Energy Chg 1	Energy Chg 2	Comments
Residential	Urban	Service Chg $22.39/billing period		Flat energy charge 11.18¢/kWh		Includes farms and churches. Business portion ≤ 2 kW. Flat energy charge Urban/ rural distinction
	Rural or Seasonal	Service Chg $24.56/billing period		Flat energy charge 11.18¢/kWh		
General Service	Non-res/industrial/ lighting/ unmetered	Service Chg $23.36/billing period	Demand Chg $10.75/kW over 20 kW	Energy charge block 13.45 ¢/kWh for ≤ 5000 kWh	Energy charge block 9.54 ¢/kWh for ≥ 5000 kWh	Applies to Res with bus load > 2kW. Warehouse & storage if >50% load. Declining energy blocks
General Service II	Closed	Service Chg $23.36/billing period	Demand Chg for demand ≥ 20kW. Lesser of: $7.18/kW or 3.577 ¢/kWh	Energy charge block 13.46 ¢/kWh for ≤ 5000 kWh	Energy charge block 10.32 ¢/kWh for ≥ 5000 kWh	Closed to new/ modifying entrants. Declining energy blocks
Small Industrial	5 – 750 kW		Demand Chg $7.14/kW	Energy charge block 13.84¢/kWh for ≤ 100 kWh	Energy charge block 6.54¢/kWh for > 100 kWh	Declining energy blocks. Process load on a farm separately metered on this rate.
Large Industrial	>750kW		Demand Chg: $14.55/kW	Energy charge 5.38¢/kWh		Billing Demand is formulaic. See tariff. Load attraction/ expansion, surplus and interruptible options
Wholesale (Municipal)			Demand Chg: $14.64/kW	Energy charge 6.86¢/kWh		St. John and Edmundston

[58] As at September 2019

Table B-5 Hydro Quebec[59]						
Class	Customer type	Customer Chg	Demand Chg	Energy Chg 1	Energy Chg 2	Comments
Residential D	(Domestic Rate D) Max demand <65kW	Service Chg $0.4064/day of contract period		Energy charge block 6.08 ¢/kWh up to 40kWh*# of days in contract period	Energy charge block: 9.38 ¢/kWh remainder	Weekly contracts. May include farm load if <10kW. Flat energy charge. INCLINING energy charge. Net metering option. Winter Credit Option (50¢/kWh) for critical peak period (CPP) reduction when HQ requests
Residential "Rate Flex D"	Residential Winter demand and energy management incentive rate	Service Chg $0.4064/day of contract period		Energy charges Winter: 4.28 ¢/kWh up to 40kWh*# of days in contract period (nonCPP) 7.36 ¢/kWh (nonCPP) residual 50.00 ¢/kWh during CPP	Energy charges Summer: 6.08 ¢/kWh up to 40kWh*# of days in contract period 9.38 ¢/kWh residual	Seasonal energy charges. Critical peak period pricing. INCLINING energy block pricing.
Residential DP	Demand metered (Domestic)	minimum bill $12.18/mo single-phase or $18.27 three-phase	Demand charge for >50kW: Winter $6.21/kW Summer $4.59/kW	Energy charge block 5.88 ¢/kWh for ≤ 1200 kWh/mo	Energy charge block 8.94 ¢/kWh for remainder	Seasonal Demand charges for residential custs. INCLINING energy charge. Photosynthetic Lighting rate option available.
Residential DM	Multi-res buildings					Closed to new entrants in 2009
Residential DT	Dual energy residential (primary elec space heat with fuel backup)	Service Chg $0.4064/day of contract period	Demand charge: $6.21 /kW/mo above base base demand amount	Energy charge block 4.37 ¢/kWh when temp higher than -15 C 25.55 ¢/kWh when temp		System switches automatically based on outside temperature. Ability to apply to multi-res.

[59] As at April 2019. HQ tariffs are primarily designed based on size of demand and energy requirements (i.e. ; medium, large) rather than General or Industrial classifications. Rate Class GD has not been included (IPP backup tariff). Tariffs also include provision for testing and run-up of new customer equipment. Additional Electricity, Economic Development, Industrial Revitalization, Customer Owned Generation Backup, Auxiliary Boiler Backup, and Load Retention tariffs have not been included. HQ has Interruptible Credit options available to several classes, and includes day-ahead as well as real-time notification options.

				lower than -15 C		and small farms.
Small General G	Avail for custs requiring < 65kW	Service Chg $12.33 /mo	Demand charge for >50kW: $17.64/kW	Energy charge block 9.90 ¢/kWh for ≤ 15,090 kWh	Energy charge block 7.62 ¢/kWh for remainder	Declining energy blocks[60]. Net metering option available. Winter CPP Credit (50¢/kWh) available.
Small General "Rate Flex G"	Small General Winter demand and energy management incentive rate	Service Chg $12.33 /mo		Energy charges Winter: 8.26¢/kWh (nonCPP) 50.00 ¢/kWh during CPP	Energy charges Summer: 9.9 ¢/kWh	Seasonal energy charges. Critical peak period pricing
General Service M	Avail for custs requiring > 50kW		Demand Chg $14.58/kW billing demand per month	Energy charge block 5.03 ¢/kWh first 210,000 kWh/mo per kW maximum demand	Energy charge block 3.73 ¢/kWh for remainder	Declining energy blocks. Some flexibility of which class load is billed, contract period etc. Interruptibility credit option.
Medium General G9	Avail for custs requiring limited use of billing demand but > 65kW		Demand Chg $4.23/kVA	Energy charge 10.08 ¢/kWh		Flat energy charge. Some flexibility of which class load is billed, contract period etc.
Experimental BR	Avail for custs employing DC vehicle charging stations			Energy charge block 11.04 ¢/kWh based on the product of the maximum power demand up to 50 kW, the load factor and the number of hours in the consumption period	Energy charge block 20.69 ¢/kWh in excess of 50 kW that is, the product of the excess power demand, the load factor up to 3%, and the number of hours 16.27¢ /kWh for remainder	Three energy blocks, INCLINING rate. HQ collecting individual consumption data
"Rate Flex M"	Avail to Rate M custs to assist with critical peak management		Demand Chg $14.58/kW	Energy charges Winter: 3.17¢/kWh (nonCPP)	Energy charges Summer: 5.03 ¢/kWh first	Experimental. Seasonal energy charges. Declining summer block rates.

[60] As of 2019, HQ is setting out to reduce/eliminate this declining block pricing structure over time. This is to be achieved by increasing the second block price.

				50.00 ¢/kWh during CPP	210,000 kWh 3.73 ¢/kWh for remaining	
“Rate Flex G9”	Avail to Rate G9 custs to assist with critical peak management		Demand Chg $4.23/kW	Energy charges Winter: 8.10¢/kWh (nonCPP) 50.00 ¢/kWh during CPP	Energy charges Summer: 10.08 ¢/kWh	Experimental. Seasonal energy charges. Flat energy charge in summer and nonCPP winter.
Large General LG	Avail for custs requiring >5,000 kW but non-industrial		Demand Chg $13.26/kW	Energy charge 3.46¢/kWh		Flat energy charge. Interruptibility credit options.
Large Industrial L	Avail for custs requiring >5,000 kW Primarily industrial		Demand Chg $12.90/kW	Energy charge 3.28¢/kWh		Flat energy charge. Peak day Demand price surcharge for kW above contract. Interruptibility credit options.
Large Power H	Avail for custs whose use is primarily outside of winter peak days		Demand Chg $5.31/kW	Energy charge 5.36¢/kWh outside of winter peak days 18.08¢/kWh on winter peak days		Flat energy charge other than peak days.

Table B-6 Manitoba Hydro[61]						
Class	Customer type	Customer Chg	Demand Chg	Energy Chg 1	Energy Chg 2	Comments
Residential	(Domestic)	Service Chg $8.62/mo <200A service $17.24/mo >200A service Seasonal cust $103.44/yr		Flat energy charge 8.740¢/kWh		Different cust chg for 200A+ service. Flat energy rate.
Residential First Nations on Reserve		Service Chg $8.08/mo <200A service $16.16/mo >200A service		Flat energy charge 8.196¢/kWh		Different cust chg for 200A+ service. Flat energy rate.
Small General Non-demand	Avail for custs using < 50kVA	Service Chg $20.09/mo single phase $31.58/mo three phase		Energy charge block 9.012 ¢/kWh for ≤ 11,000 kWh	Energy charge block 6.662 ¢/kWh for remainder	Declining energy blocks.
Small General Demand	Avail for custs using 51-200 kVA	Service Chg $20.09/mo single phase $31.58/mo three phase	Demand Chg $10.78/kVA above 50 kVA	Energy charge block 9.012 ¢/kWh for ≤ 11,000 kWh	Energy charge block 6.662 ¢/kWh next 8500 kWh Block 4.211 ¢/kWh remainder	3 Declining energy blocks. Seasonal rate and billing option available
General Service Medium	Avail for custs using > 200kVA but less than 750 kVA	Service Chg $31.58/mo	Demand Chg $10.78/kVA above 50 kVA	Energy charge block 9.012 ¢/kWh for ≤ 11,000 kWh	Energy charge block 6.662 ¢/kWh next 8500 kWh Block 4.211 ¢/kWh remainder	3 Declining energy blocks. Seasonal rate and billing option available
Large General	Avail for custs using > 750 V but less than 30 kV		Demand Chg $9.14/kVA	Energy charge 3.955 ¢/kWh		Availability Based on service voltage. Flat energy rate
Large General II	Avail for custs using > 30 kV but less than 100 kV		Demand Chg $7.75/kVA	Energy charge 3.639 ¢/kWh		Availability Based on service voltage. Flat energy rate
Large General III	Avail for custs using > 100 kV		Demand Chg $6.90/kVA	Energy charge 3.529 ¢/kWh		Availability Based on service voltage. Flat energy rate.

61 As at June 2019. MH tariffs are primarily designed based on size of demand, voltage and/or energy requirements (i.e. ; medium, large) rather than General or Industrial classifications. Some tariffs such as the Diesel Gen Supply rate have not been included here. MH offer options for low load factor General customers, Surplus rate and Curtailable demand.

Table B-7 SaskPower[62]						
Class	Customer type	Customer Chg	Demand Chg	Energy Chg 1	Energy Chg 2	Comments
Residential	(Domestic)	Service Chg $22.79/mo urban $32.90/mo rural		Flat energy charge 14.228¢/kWh urban 14.229 ¢/kWh rural		Urban/rural differentiation. Does not include farms. Flat energy rate. Plus 0.3095 ¢/kWh Fed carbon chg
Farm Standard Rate	For farm and associated res load <3,000 kVA	Service Chg $34.97/mo	Demand Chg $12.848/kVA above 50 kVA	Energy charge block 12.658 ¢/kWh up to 16,000 kWh	Energy charge block 5.488 ¢/kWh for remainder	Includes associated residential load. Declining energy blocks. Plus 0.2994 ¢/kWh Fed carbon chg
Farm Irrigation Rate[63]	For irrigation pump load used April 1 – Oct 31	Season service chg $480.28		Flat energy charge 7.078¢/kWh		Flat energy charge. Plus 0.2994 ¢/kWh Fed carbon chg
Small General	Avail for custs using < 75kVA Served at 25kV or less SaskPower-owned transformation	Service Chg $31.14/mo urban $41.49/mo rural	Demand Chg[64] above 50 kVA: $15.148/kVA Urban $15.475 /kVA rural	Energy charge block first 14,500 kWh: 13.669 ¢/kWh urban 14.399 ¢/kWh rural first 13,000 kWh	Energy charge block for remainder: 7.218 ¢/kWh urban 7.406 ¢/kWh rural	Urban/rural distinction. Declining energy blocks. Plus 0.3025 ¢/kWh Fed carbon chg
General Demand Standard Rate	Avail for custs using 75-3000 kVA SaskPower-owned transformation	Service Chg $57.94/mo urban $65.03/mo rural	Demand Chg above 50 kVA: $15.600/kVA Urban $15.600 /kVA rural	Energy charge block first 16,750 kWh: 11.987 ¢/kWh urban 11.987 ¢/kWh first 15,500 kWh rural	Energy charge block for remainder: 7.674 ¢/kWh urban 7.270 ¢/kWh rural	Urban/rural distinction. Declining energy blocks. Plus 0.3025 ¢/kWh Fed carbon chg
Small General **Customer-owned transformatio n**	Avail for custs using < 75kVA Served at 25kV or less Customer-owned transformation	Service Chg $31.14/mo urban $41.49/mo rural	Demand Chg[65] above 50 kVA: $14.618/kVA Urban $14.923 /kVA rural	Energy charge block first 14,500 kWh: 13.669 ¢/kWh urban 14.399 ¢/kWh rural first 13,000 kWh	Energy charge block for remainder: 7.218 ¢/kWh urban	Urban/rural distinction. Declining energy blocks. Plus 0.3025 ¢/kWh Fed carbon chg

[62] As at March 2018. Non-farm Irrigation Rate, Oil Field rates and Unmetered Rate not included here.

[63] Interruptible option available for pumping stations >1,000 kVA. Closed to new entrants after 1997.

[64] Small and Standard Rate TOU metered customers' (both SaskPower-owned transformation and customer-owned rates) billing demand is the greater of the on-peak demands or 85% of overall monthly maximum demand

[65] Small and Standard Rate TOU metered customers' (both SaskPower-owned transformation and customer-owned rates) billing demand is the greater of the on-peak demands or 85% of overall monthly maximum demand

					7.406 ¢/kWh rural	
General Demand Standard Rate **Customer-owned transformation**	Avail for custs using 75-3000 kVA Served at 25kV or less Customer-owned transformation	Service Chg $242.35/mo urban $299.13/mo rural	Demand Chg above 50 kVA: $13.953/kVA Urban $13.953 /kVA rural	Energy charge 7.253 ¢/kWh urban & rural		Urban/rural distinction re Service Chg. Flat energy rate. Plus 0.3025 ¢/kWh Fed carbon chg
Power Standard Rate 25kV[66]	Large commercial and industrial customers >3,000 kVA at 25kV service Customer-owned transformation	Service Chg $6188.90/mo	Demand Chg $10.906/kVA	Energy charge 6.902 ¢/kWh		Flat energy charge. Plus 0.2784 ¢/kWh Fed carbon chg
Power Standard Rate 75kV	Large commercial and industrial customers >3,000 kVA at 75kV service Customer-owned transformation	Service Chg $7093.95/mo	Demand Chg $8.405/kVA	Energy charge 6.227 ¢/kWh		Flat energy charge. Plus 0.2784 ¢/kWh Fed carbon chg
Power Standard Rate 100kV+	Large commercial and industrial customers >3,000 kVA at 100kV+ service Customer-owned transformation	Service Chg $7615.80/mo	Demand Chg $8.284/kVA	Energy charge 6.109 ¢/kWh		Flat energy charge. Plus 0.2784 ¢/kWh Fed carbon chg
Power TOU Rates[67]	Available to large commercial, farm and industrial loads Customer-owned transformation	Service Chg $6188.90/mo	Demand Chg $10.906/kVA	Energy charges: 7.475 ¢/kWh on-peak 6.475 ¢/kWh off-peak		Non-seasonal TOU-varying energy prices on and off-peak. Plus 0.2784 ¢/kWh Fed carbon chg

[66] Power Standard Rates effective October 2018

[67] Only 25kV tariff shown for illustrative purposes. Tariffs are also available to customers served at 75 and 100kV+.

Table B-8 Fortis Alberta[68]						
Class	Customer type	Customer Chg	Demand Chg	Energy Chg 1	Energy Chg 2	Comments
Residential	Domestic	Service Chg: $0.8124/day		Energy charge 6.299 ¢/kWh		Flat energy charge
Farm Service	Rural Domestic use plus farm load served from distn[69]		Demand chgs: $0.5078/kVA /day first 5kVA $0.4227/kVA residual	Energy charge 4.144 ¢/kWh		Specific farm rate. Flat energy charge.
Farm Irrigation Rate	Farm irrigation Apr-Oct		Demand chgs: $0.1647/kW /day	Energy charge 7.7145 ¢/kWh		Specific farm rate. Flat energy charge.
Small General Demand	General service customers requiring <75kW		Demand chgs: $0.77807/k W/day first 2kW $0.51425/k W residual	Energy charge 1.8856 ¢/kWh first 6.575 kWh/kW/day 0.5626¢/ kWh/kW/day residual		Customer charge via demand charges.
General Service	General customers with <2000 kW demand		Demand chgs: $0.37073/k W/day first 50kW $0.23420/k W next 450kW $0.20798/k W residual Peak metered demand $0.26971/k W-day	Energy charge 5.759 ¢/kWh		Customer charge via demand charges. Additional direct charge for peak demand in month.
Large General	>2,000 kW	Service Charge $20.35/day plus $0.12/kW/day of capacity plus $17.79/km connection/day	Peak Demand charge: $0.23467 \kW-day	Energy charge 0.5588 ¢/kWh		Complex service charge. Flat energy charge

[68]Alberta has competitive electricity generation service and retail choice. Some companies provide generation, some transmission, some local distribution, some retail to customers, and some provide combinations of these services. Transmission and distribution services and tariffs are fully regulated, but generation is based on a competitive market model and the retail service sector is partly regulated. As a result, comparison of tariffs in Alberta with those in PEI is of limited value. Fortis Alberta selected because it has specific farm rates (As at January 2019).

[69] A separate tariff is offered (REA farm) for Rural Electrification Association customers and farmers who own complete electric service extension. Not included in this table.

Table B-9 BC Hydro[70]						
Class	Customer type	Customer Chg	Demand Chg	Energy Chg 1	Energy Chg 2	Comments
Residential	(Domestic)	Zone 1 Service Chg 20.9¢/day [71]		Energy charge block 9.45 ¢/kWh up to 675 kWh/mo	Energy charge block 14.17 ¢/kWh	Does not include farms. Inclining block energy rate.
Exempt Residential	For Zones I and 1B farms	Service Chg 22.29¢/day		Flat energy charge 11.32¢/kWh		Includes residential load. Flat energy charge.
Farm Irrigation Rate	For irrigation pump motor load >746W used seasonally	Minimum Chg: $6.12/kW connected load 8 mos irrigation season $48.94/kW if non-irr season energy >500kWh		Energy charge: 6.12¢/kWh irrigation season 6.12¢/kWh first 150kWh , 48.52¢/kWh remaining non irr season		Flat energy charge during irrigation season. High cost if used during non-irrigation season
Small General	Avail for custs using < 35kW	Service Chg 36.45/¢/day		Flat energy charge 12.53¢/kWh		
Medium General Demand	Avail for custs using 35-150 kW and <550,000 kWh/year	Service Chg 26.73/¢/day	Demand Chg $5.42/kW	Flat energy charge 9.68¢/kWh		
Large General	Avail for custs using >150 kW and >550,000 kWh/year	Service Chg 26.73/¢/day	Demand Chg $12.34/kW	Flat energy charge 6.06¢/kWh		
Shore Power Rate	Avail to port customers serving ship load on an interruptible basis	Service Chg $150/mo		Flat energy charge 10.510¢/kWh		Tariff to facilitate service to vessels in port
Transmission Service Stepped Rate	Avail for custs served at 60kV+		Demand Chg $8.697/kVA [72]	Energy charge 5.098¢/kWh pre-CBL establishment 4.535¢/kWh for up to 90% of CBL energy, 10.160¢/kWh for additional		Higher rate for energy above 90% of historical encourages conservation. Peak demand pricing encourages peak management.
Transmission Service TOU Rate	Avail for custs served at 60kV+		Demand Chg $8.697/kVA	Seasonal (W,Spring, Other) HLH and LLH[73] pricing. Increasing energy block charges above 90% of CBL.		

[70] As at March 2019. BC Hydro offers a variety of rates across three zones in BC. Not all rates offered are shown in this table.

[71] BC Hydro also provides separate rates for residential services in Zone II (remote and northern).

[72] Demand charge based on demand in High Load Hours

[73] High Load Hours and Low Load Hours as defined in tariff

Table B-10 Fortis BC[74]						
Class	Customer type	Customer Chg	Demand Chg	Energy Chg 1	Energy Chg 2	Comments
Residential	Domestic use incl motors of <5HP	Service Chg $34.56 for two month billing period		Energy charge block 10.799 ¢/kWh up to 1600 kWh/2mo (800kWh if monthly)	Energy charge block 14.320 ¢/kWh for remainder	Bi-monthly billing period. Monthly cost and kWh threshold is half. Does not include farms. Inclining block energy rate.
Exempt Residential	For domestic incl farms	Service Chg $37.76 for two month billing period		Flat energy charge 11.866¢/kWh		Includes associated residential load. Requires BC farm designation. Flat energy charge.
Farm Irrigation and Drainage Rate	For irrigation or drainage pump motor load used Apr-Oct[75]	Service Chg $22.31/mo		Flat energy charge 7.312¢/kWh		Flat energy charge during irrigation season. Meter is read/estimated and bill rendered monthly or bi-monthly.
Small General	Avail for custs using < 40kW	Service Chg $46.46/2 mos		Flat energy charge 10.100¢/kWh		Flat energy charge.
General Demand	Avail for custs using 40-500 kW	Service Chg $41.92/mo	Demand Chg $10.52/kW for >40kW	Energy charge block: 7.497¢/kWh first 8000 kWh	Energy charge block: 7.084 ¢/kWh remaining	Declining energy block rate.
Commercial Secondary TOU	General custs <500kW and served at secondary distn[76]	Service Chg $16.64/mo		Summer: On-peak 15.273¢/kWh Off-peak 4.949¢/kWh Other: On-peak 15.273¢/kWh Off-peak 4.949¢/kWh		Season price variation enabled but only definition of on and off peak vary. Prices and period definitions vary for Primary service customers.

[74] Interim rates effective January 2020. Pending BCUC approval of FortisBC multi-year rate plan and 2020 rates. Fortis BC has been included as an example because it has specific rates for farm load. No specific tariffs for industrial load. Not all tariffs offered are necessarily shown in this table (e.g.; Commercial Standby tariff, Wholesale tariff, Lighting). Green Power may be purchased through use of a Rider on most tariffs.

[75] Customer is transferred to other-wise applicable commercial rate for consumption outside of irrigation season. A year-round seasonally varying TOU tariff is also available for customers who wish to use it.

[76] General customers <500kW served at primary distribution voltage also have TOU rate available. Rates vary by season and include a Shoulder period.

Large General	Avail for custs using >500 kVA	Service Chg $954.49/mo	Demand Chg $9.28/kVA	Flat energy charge 5.627¢/kWh		Flat energy charge.
Large General TOU Rate	Avail to General customers >500kVA and served at Primary Distn[77]	Service Chg $2255.49/mo		Winter: On-peak 22.902¢/kWh Off-peak 4.669¢/kWh Summer: On-peak 21.987¢/kWh Off-peak 3.634¢/kWh Shoulder: On-peak 5.274¢/kWh Off-peak 2.782¢/kWh		

[77] A similarly structured tariff is offered for Large Commercial customers served at transmission voltage levels.

APPENDIX C

MARITIME ELECTRIC COMPANY, LIMITED

FARM RATE STUDY
Preliminary draft – June 2020

MARITIME ELECTRIC COMPANY, LIMITED

FARM RATE STUDY
Preliminary draft – June 2020

TABLE OF CONTENTS

Executive summary

The context for this Study is the declining block rate structure in Maritime Electric's existing Residential Rate, and the desire to eliminate the lower price for the second block energy charge. However, elimination of the second block would result in a significant increase in electricity bills for large farms. The purpose of this Study is to investigate possible alternative rates for large farms.

This preliminary draft is essentially the same as the preliminary draft circulated internally at Maritime Electric in November 2019 for discussion. It is based on 12 months of hourly metered load data. A final report is planned for late in 2020, based on 24 months of hourly metered data.

Maritime Electric operates under cost of service regulation, which means that the rates charged to customers are intended to recover the cost of providing service. The 2017 Cost Allocation Study estimated a revenue to cost ratio of 82 % for farms served under the Residential Rate. This indicates that moves to better match revenues and costs will result in significant increases in bills for large farms.

To gain a better understanding of electricity usage by farms, in the first half of 2018 Maritime Electric installed meters capable of storing hourly load data at 88 of the larger farms in PEI. Based on the first 12 months of hourly metered load data (July 2018 to Jun 2019), the estimated 2017 revenue to cost ratio for farms is 86 %. This is greater than the 82 % estimate in the 2017 Cost Allocation Study, but still less than the minimum acceptable level of 90 % in the short term and 95 % for the long term.

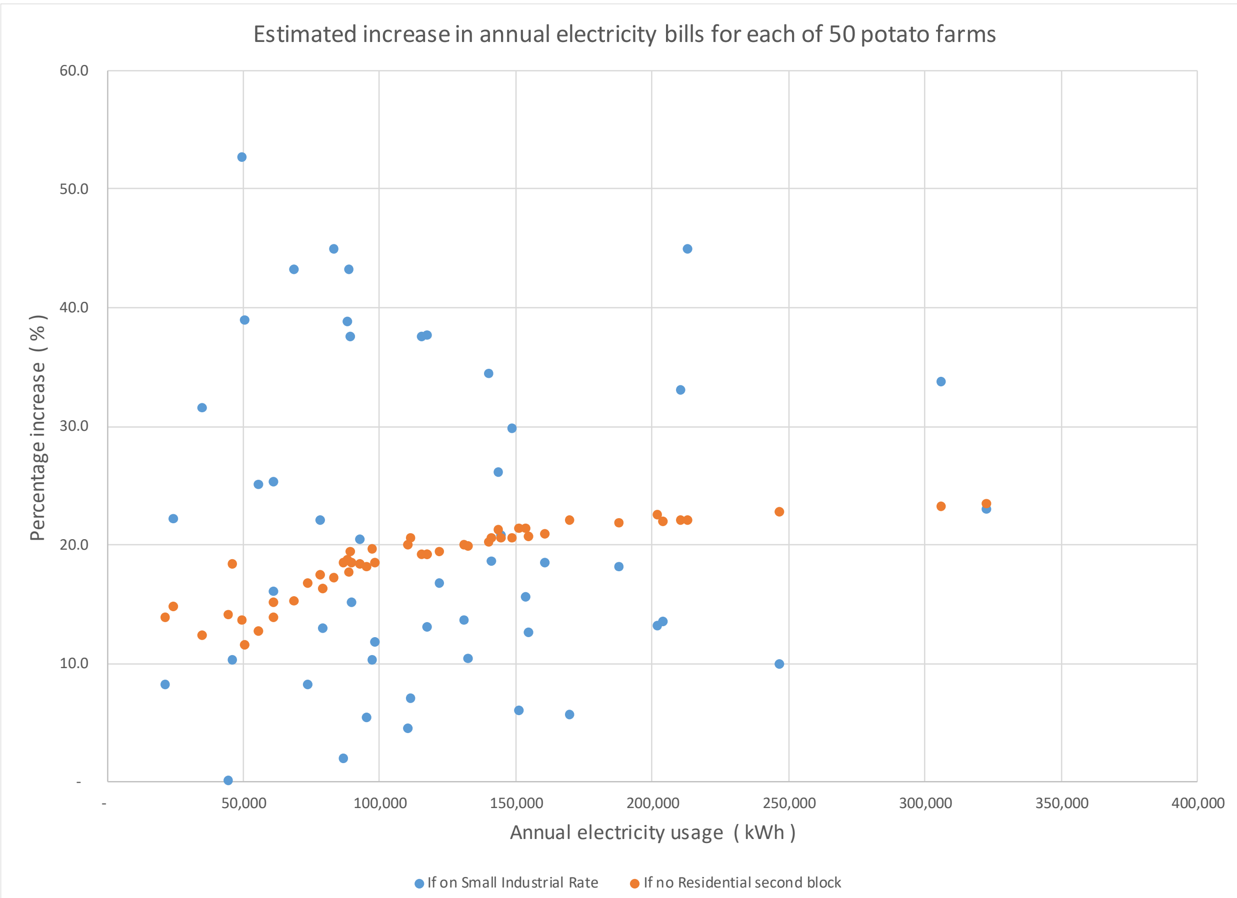
The breakdown of the 88 hourly data meters by farm types is as follows:
50 for potato farms
30 for dairy farms
3 for hog farms
5 for poultry farms (effectively 4 farms – one meter was installed on a grain dryer load)
88 in total

An option that was considered as an alternative to the Residential Rate for large farms is to create a separate rate class for farms. However, when the 2017 average allocated costs for the 88 farms with hourly metering were compared to the March 1, 2017 charges under Maritime Electric's existing Small Industrial Rate, there was a good match between the two. This means that a separate rate class created just for farms would normally be similar to the Small Industrial Rate. Also, the 2017 Cost Allocation Study estimated a revenue to cost ratio of 102 % for the Small Industrial Rate. For these reasons it is recommended to make farms eligible for service under the Small Industrial Rate.

Making farms eligible for service under the Small Industrial Rate will mitigate the impact on large farms of elimination of the second energy block in the Residential Rate. Of the 87 large farms for which hourly metered data was collected, approximately half would be better off moving to the Small Industrial Rate when the Residential second energy block is eliminated. On the Small Industrial Rate their bill increases would be mostly in the 10 % to 20 % range, as compared to increases of 20 % to 25 % under the Residential Rate with no second energy block.

The other half of the 88 large farms would be better off staying on the Residential Rate. They would experience bill increases mostly in the 10 % to 20 % range after the second energy block is eliminated. However, for both groups these are still large increases. A phase in period is recommended, with increases limited to no more than 5 % in any one year.

The following chart provides a graphical summary of the above discussion. It shows the estimated increases in electricity bills for the 50 potato farms with hourly metering. Similar results apply for the other 37 farms with hourly metering.



There appears to be potential for a Time of Use (TOU) rate. Some of the large farms could save an estimated 10 % on average on their bills under a TOU rate. The saving would come from lower demand charges by shifting load away from the 4:30 p.m. to 7:30 p.m. time period, which is when the annual system peak load occurs. This time period is also when the majority of Maritime Electric's monthly peak loads occur during the course of a year. However, consultation with farmers would be necessary to confirm that such load shifting would not be disruptive to their operations.

'1. Introduction

The context for this Study is the declining block rate structure in Maritime Electric's existing Residential Rate, and the desire to eliminate the lower price for the second block energy charge. However, the impediment to eliminating the second block has been the fact that farms are eligible for service under the Residential Rate, with no limit on the amount of electricity used. Elimination of the second block would result in a significant increase in electricity bills for large farms, as shown in the table below.

Table 1-1: INDICATIVE IMPACT OF ELIMINATION OF SECOND ENERGY BLOCK

			Monthly bill for a large farm customer			
			With second block		With second energy block eliminated	
Rural Residential Rate effective March 1, 2017			(kWh)	($)	(kWh)	($)
Monthly service charge	26.92	$ / month		26.92		26.92
First block energy	0.1396	$ / kWh	2,000	279.20	10,000	1,396.00
Second block energy	0.1108	$ / kWh	8,000	886.40	-	-
			10,000	1,192.52	10,000	1,422.92
Reduction in first block	0.0043	$ / kWh	for same revenue from Residential			(43.00)
						1,379.92
With the second energy block eliminated, the monthly bill would have been					16	% higher.

The purpose of this Study is to investigate possible alternative rates for large farms before the elimination of the second block energy charge in the Residential Rate.

'2. Estimates of farm electricity usage

The first step in this Study was to gain an understanding of electricity usage by farms. Three different approaches were used:

- Available data from Maritime Electric's billing system
- Top down estimate using industry energy intensity factors
- Installation of meters at a some of the larger farms to gather hourly load data

Available data from Maritime Electric's billing system

There are approximately 2,200 Residential Rate accounts in the Maritime Electric billing system that have a farm Standard Industrial Classification (SIC) code assigned to them. In 2017 these customers used a total of 52,329 MWh. The annual usage per customer covers a wide range, from more than 500,000 kWh per year at the high end of the range to less than what a small household uses at the low end of the range. The majority of these customers would not be affected by the elimination of the second block energy charge, because they had little or no second block energy usage.

	Table 2-1: RESIDENTIAL RATE ELECTRICITY USAGE BY SIC CODE FOR FARMS FOR 2017		
Assigned SIC Code	Standard Industrial Classification (SIC) Description	Usage (MWh)	Number of customers
011	Livestock Farms (Except Animal Specialties)	16,368	836
012	Other Animal Specialty Farms	2,989	172
013	Field Crop Farms	16,792	532
014	Field Crop Combination Farms	2,887	108
015	Fruit and Other Vegetable Farms	487	27
016	Horticultural Specialties	3,090	9
017	Livestock, Field Crop and Horticultural Comb. Farms	8,954	527
103	Fruit and Vegetable Industries	762	12
	Subtotal for 2017 Cost Allocation Study (Residential - Farms)	52,329	2,223
Note:	The 2017 Cost Allocation Study shows 2094 as the average number of bills per month for farms. This differs from the 2,223 number of customers shown above because some of the accounts are seasonal and thus only billed during half of the year.		

The SIC codes assigned to Farms in the Company's billing system have two shortcomings. The first is that they do not provide a breakdown by individual farm types, such as potato farms and dairy farms. A breakdown by individual farm type can assist in estimating the loads and costs imposed on the electricity system by the various types of farms, which could then inform rate design. The second shortcoming is that not all farms served under the Residential Rate have been assigned a farm SIC code. This has not been a problem in the past because all farms are currently eligible for service under the Company's Residential Rate, regardless of size. However, for the 2017 Cost Allocation Study this was the best information available and was used to analyze "farms" as a subset of the Residential Rate class.

Top down estimate using industry energy intensity factors

To obtain an estimate of the electricity used by the different types of farms in PEI, a top-down approach was taken. The starting point was production statistics for PEI's agriculture sector. Electricity intensity factors were applied to the various production volumes to obtain estimates of annual electricity usage. The table below shows the results for 2017.

	Table 2-2: ESTIMATED PEI FARMS ELECTRICITY USAGE FOR 2017					
		Intensity of	2017 PEI farming statistics			Estimated
Type	Main	electricity	Area			electricity
of crop /	uses for	usage	harvested	Production	Production	usage
farming	electricity	(kWh / **)	(acres)	quantity	units	(MWh)
Potato:	Fan power for storage	kWh / tonne	83,200	(24.46 million cwt)		
- table/seed	cooling and ventilation	68	35 %	389,000	tonnes	23,807
- processing		24	65 %	723,000	tonnes	15,617
Grain crops:	Fan power for drying	kWh / tonne				
- wheat	and storage ventilation	13.3	37,000	56,800	tonnes	755
- barley		10.6	54,000	78,400	tonnes	831
- oats		10.6	11,000	11,100	tonnes	118
Soybeans	Fan power for drying	5.6	50,000	49,000	tonnes	273
	and storage ventilation	kWh / tonne				
Dairy (milk)	milk cooling, water heating,	0.10		117	million kg	11,700
	milking machinery, ventilatic	kWh / kg		(117 million litres)		
Hog	Ventilation and	30		76,000	hogs	2,280
	radiant heating	kWh / hog				
Poultry - meat	Ventilation, lighting	0.23		5.0	million kg	1,150
	and feeding	kWh / kg				
Poultry - eggs	Ventilation, lighting	0.21		3.7	million dozen	777
	and feeding	kWh / dozen				
Total						57,307
	For potatoes the estimate is based on 10 % of the crop being used directly					
	from the field, with 90 % going into storage.					

The table shows that potato storage and handling is by far the largest user of electricity in the agriculture sector in PEI, accounting for over two thirds of electricity usage, with dairy farms being the second largest user.

In order to compare the above estimate of electricity usage by farms with the Residential Rate quantity shown in Table 2-1, a number of other factors must be taken into account. The table below does this. While the resulting reconciliation is not exact, it shows that the two approaches to estimating farm electricity usage give values that are within 10 % of each other.

Table 2-3: RECONCILIATION OF ESTIMATED FARMS ELECTRICITY USAGE WITH BILLING DATA			
			GWh
Estimate of farms electricity usage for 2017 based on intensities (Table 2-2)			57.3
	(does not include all farm types)		
Plus:	Usage by farm types not included in Table 2-2 estimate:		8.0
	(e.g. beef farms, mink farms, greenhouses, fruit and vegetable)		
Total			65.3
Electricity usage by	2,223	Residential farm accounts for 2017 (Table 2-1)	52.3
Plus:	Farm usage by Residential accounts with a non-farm SIC code		10.0
Plus:	Usage by potato warehouses on General Service Rate		8.0
Plus:	Usage for drying by grain elevators on Small Industrial Rate		1.0
			71.3
Less:	Domestic usage from same meter as for farm usage		10.9
	(estimated as the 3.5 GWh for 1,000 Residential farm accounts using less		
	than 8,100 kWh annually, and 8,100 kWh x 75 % of balance of accounts)		
Total			60.4

Installation of meters to gather hourly load data

In addition to the energy usage, measured in kilowatthours (kWh), we want to know the peak loads imposed on the grid by each farm type (referred to as NCP, or Non-Coincident Peak loads), and the amount of load for each farm type that coincides with Maritime Electric's annual system peak load (referred to as CP, or Coincident Peak loads).

To provide data for estimating farm coincident peak and non-coincident peak loads, in the first half of 2018 Maritime Electric installed meters capable of storing hourly kWh load values at 88 of the larger farms, as follows:

50 for potato farms
30 for dairy farms
3 for hog farms
5 for poultry farms (effectively 4 farms – one meter was installed on a grain dryer load))
88 in total

The following three tables summarize the metered data for July 2018 through June 2019, the first 12 months for which complete data are available.

	Table 2-4: COINCIDENT PEAK AND NON-COINCIDENT PEAK LOADS											
	2018	-	-	-	-	2018	2019	-	-	-	-	2019
	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
MECL monthly system peak load:												
- date	25	1	6	18	22	27	3	26	7	5	22	28
- hour ending	18:00	18:00	17:00	19:00	18:00	18:00	18:00	19:00	8:00	9:00	10:00	12:00
- net MWh / h	200.5	197.4	171.6	187.2	241.5	243.2	243.1	245.8	221.2	192.0	184.2	165.7
Coincident Peak loads (kW):												
- 50 potato farms	425	425	275	665	1,315	1,095	1,180	970	935	875	727	712
- 30 dairy farms	690	699	639	630	756	789	732	801	801	678	607	480
- 3 hog farms	243	223	289	175	176	187	198	211	220	247	243	292
- 4 poultry farms	81	95	69	45	69	53	50	70	56	57	65	67
	1,439	1,442	1,272	1,515	2,316	2,124	2,160	2,052	2,012	1,857	1,642	1,551
Farms as a group NCP loads (kW):												
- date	5	2	4	22	19	5	2	11	1	11	13	3
- hour ending	17:00	9:00	10:00	9:00	9:00	9:00	10:00	9:00	9:00	9:00	9:00	17:00
- 50 potato farms	779	562	326	1,118	1,586	1,616	1,451	1,252	1,241	857	831	833
- 30 dairy farms	613	741	711	696	736	730	738	800	768	700	655	627
- 3 hog farms	255	237	283	253	217	260	243	234	284	290	253	304
- 4 poultry farms	83	73	82	54	92	80	83	93	68	86	64	52
	1,730	1,614	1,401	2,120	2,630	2,686	2,515	2,379	2,360	1,933	1,803	1,816
Energy consumption (MWh):												
- 50 potato farms	331	219	137	442	842	831	737	641	578	412	436	430
- 30 dairy farms	400	416	377	356	355	403	417	388	391	356	350	362
- 3 hog farms	162	181	160	147	144	143	142	135	143	148	151	156
- 4 poultry farms	38	47	30	37	36	40	41	35	40	35	35	31
	930	863	704	982	1,377	1,417	1,338	1,199	1,151	951	972	979

Table 2-5: NON-COINCIDENT PEAK LOADS FOR INDIVIDUAL FARM TYPES											
	2018	-	-	-	-	2018	2019	-	-	-	-	2019
	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
Individual farm type NCP loads:												
50 Potato farms												
- monthly peak load (kW)	780	570	390	1,120	1,585	1,616	1,451	1,365	1,305	995	881	881
- date	5	2	27	22	19	5	2	28	1	1	21	4
- hour ending	17:00	11:00	15:00	9:00	9:00	9:00	10:00	14:00	14:00	14:00	14:00	10:00
30 Dairy farms												
- monthly peak load (kW)	783	777	768	750	771	801	816	846	804	744	719	746
- date	29	29	3	30	24	26	12	27	1	22	22	29
- hour ending	9:00	9:00	9:00	9:00	8:00	8:00	8:00	8:00	8:00	8:00	8:00	8:00
3 Hog farms												
- monthly peak load (kW)	316	389	335	329	377	314	306	314	298	301	297	338
- date	17	24	4	4	13	6	18	14	14	25	29	13
- hour ending	11:00	14:00	14:00	15:00	14:00	10:00	12:00	15:00	12:00	11:00	14:00	15:00
4 Poultry farms												
- monthly peak load (kW)	115	128	96	98	100	104	107	118	100	107	84	89
- date	31	7	6	18	27	19	24	27	28	16	30	11
- hour ending	16:00	14:00	14:00	14:00	10:00	12:00	9:00	11:00	10:00	10:00	14:00	14:00

Table 2-6: ANNUAL LOAD FACTORS FOR INDIVIDUAL FARM TYPES				
	50 potato farms	30 dairy farms	3 hog farms	4 poultry farms
Individual farm type NCP loads:	1,616	846	389	128
Annual consumption (MWh):	6,036	4,571	1,812	444
Farm type annual load factors (%):	43	62	53	40

The following charts show how electricity usage varies through the year for each of the four types of farms. Each chart shows the combined daily kWh consumption for the metered farms of that type. The usage by dairy, hog and poultry farms is more or less steady throughout the year, whereas the usage by potato farms appears to be largely a function of the quantity of potatoes in storage, with a minimum at the end of the summer and a peak in mid-November.

Of interest is that on each chart the major system outage on November 29, 2018 shows up as a significant reduction in usage for that day.

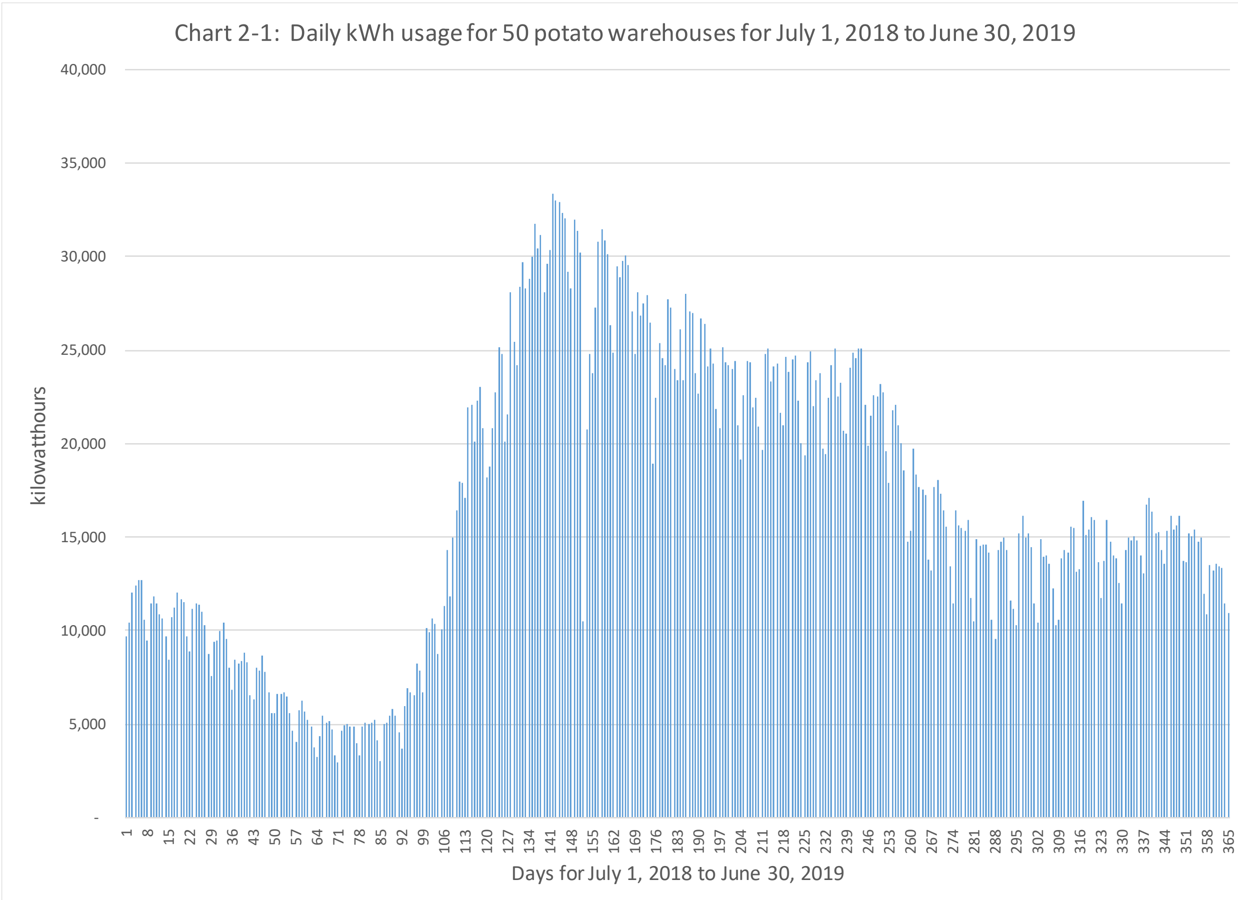


Chart 2-1: Daily kWh usage for 50 potato warehouses for July 1, 2018 to June 30, 2019
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
-
kilowatthours
1
8
15
22
29
36
43
50
57
64
71
78
85
92
99
106
113
120
127
134
141
148
155
162
169
176
183
190
197
204
211
218
225
232
239
246
253
260
267
274
281
288
295
302
309
316
323
330
337
344
351
358
365
Days for July 1, 2018 to June 30, 2019

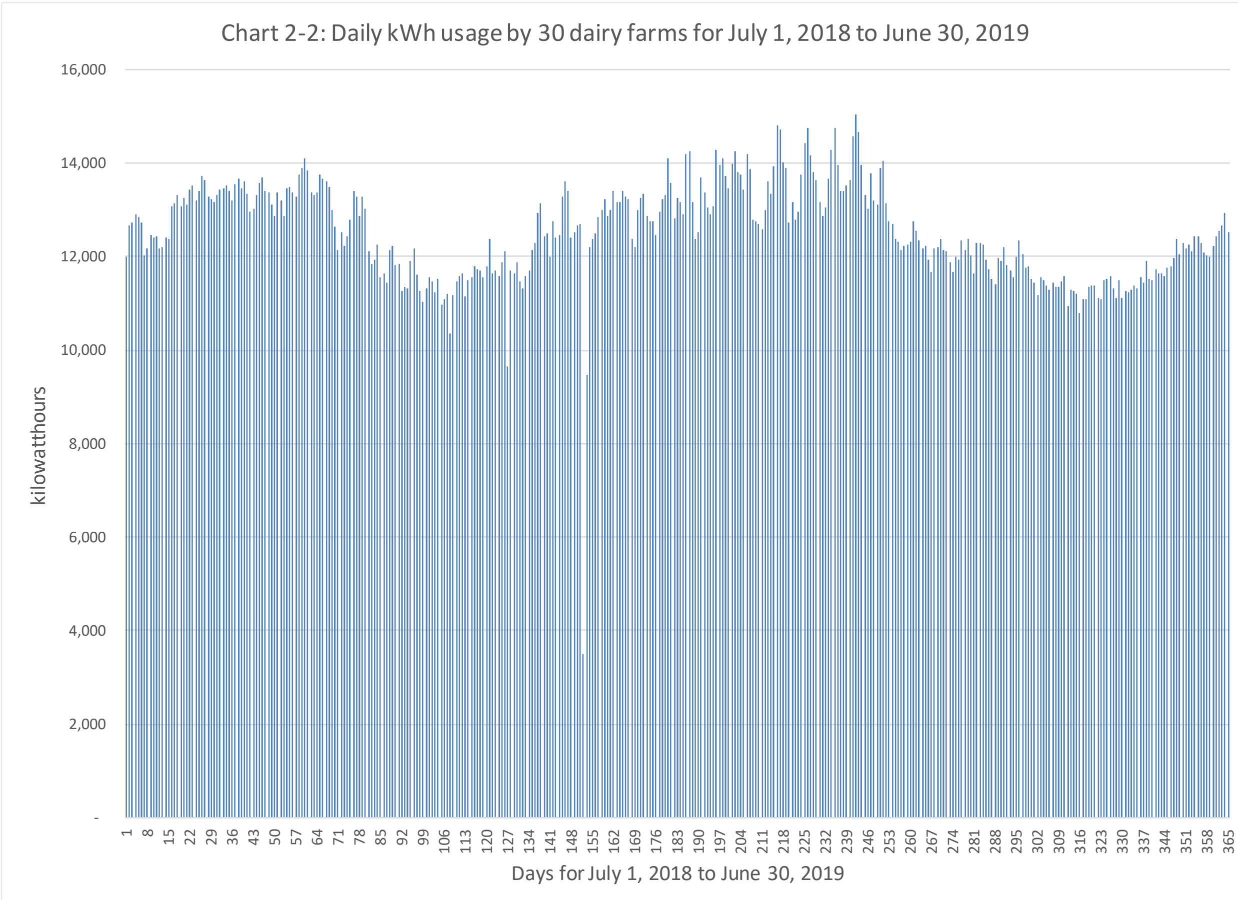


Chart 2-2: Daily kWh usage by 30 dairy farms for July 1, 2018 to June 30, 2019
kilowatthours
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
-
Days for July 1, 2018 to June 30, 2019

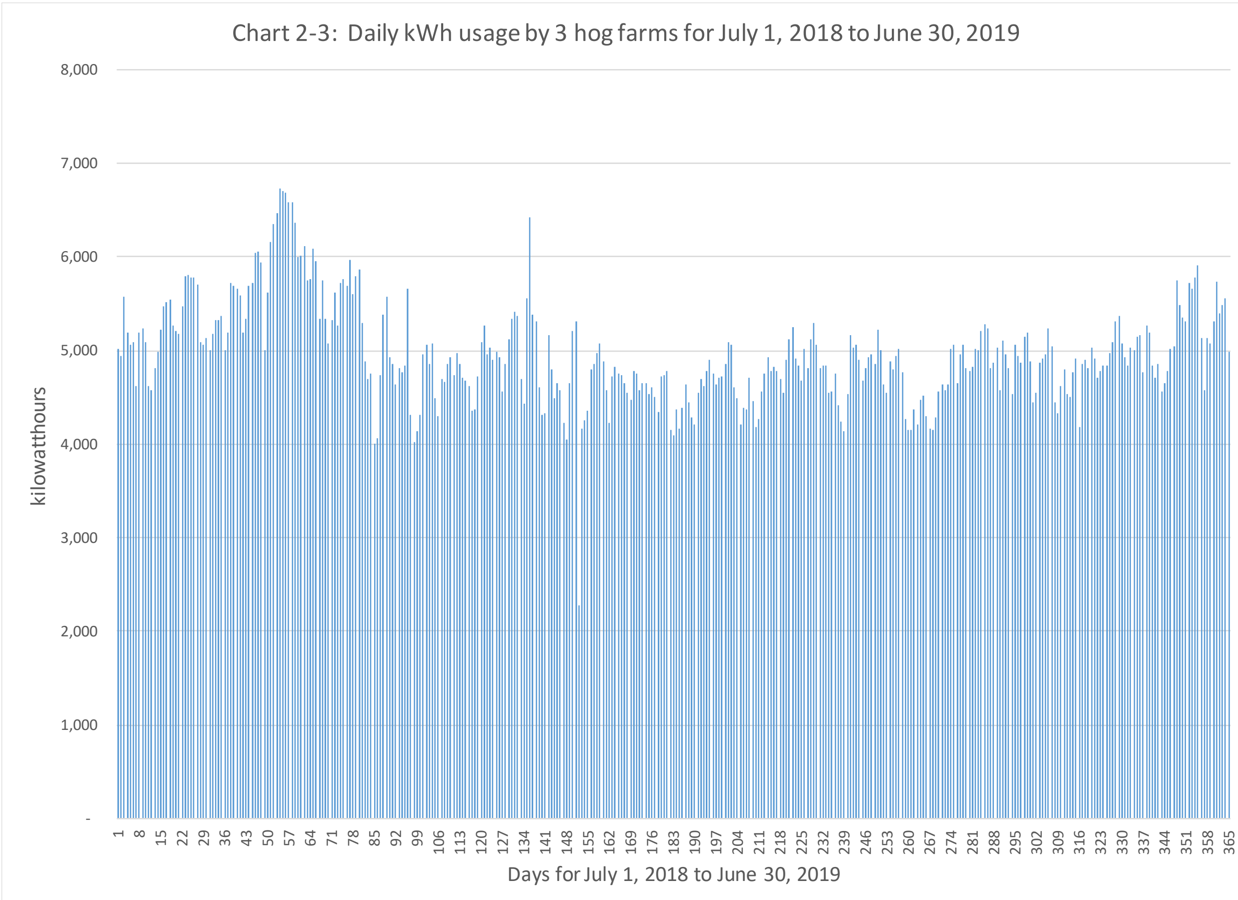
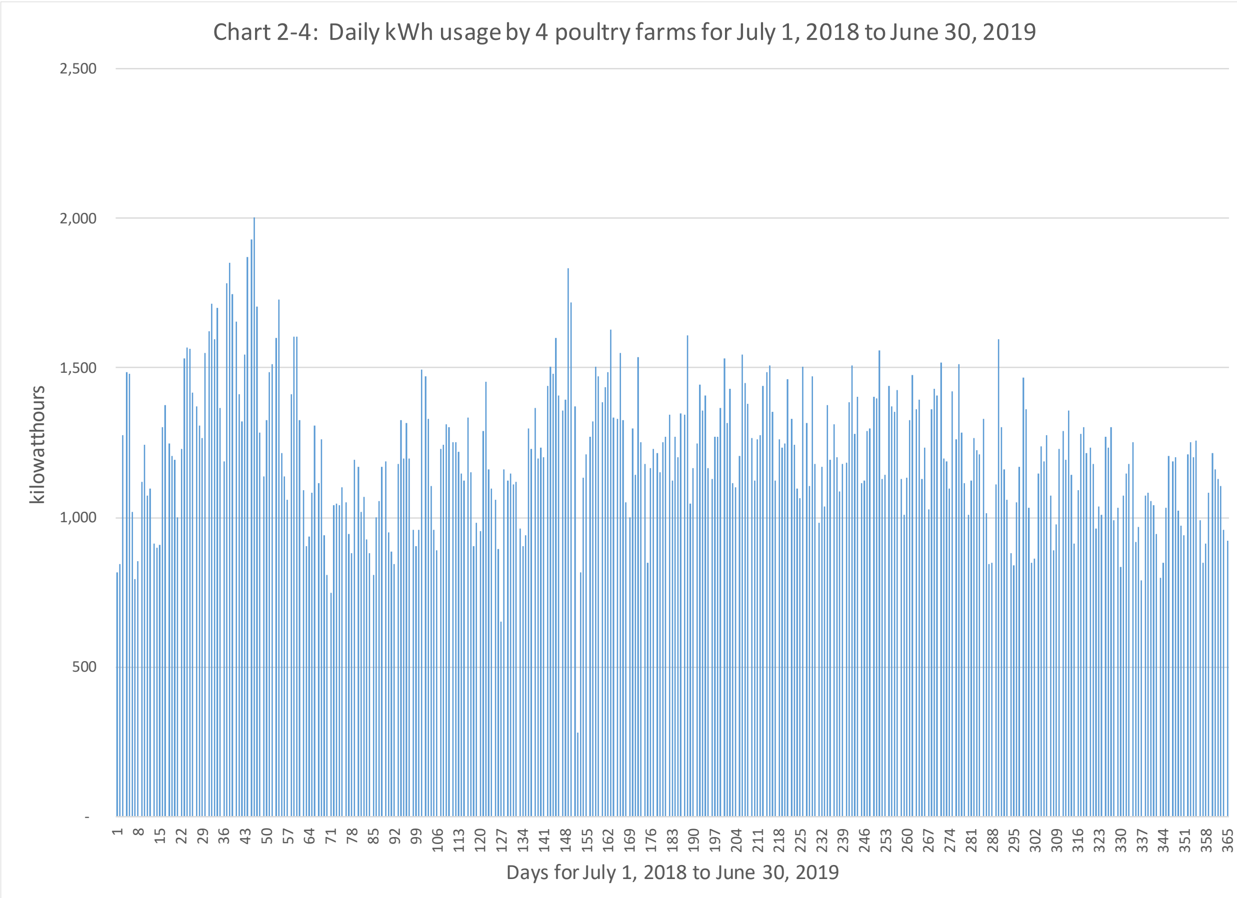


Chart 2-3: Daily kWh usage by 3 hog farms for July 1, 2018 to June 30, 2019
kilowatthours
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
-
Days for July 1, 2018 to June 30, 2019



'3. Cost allocation for farm electricity usage

Maritime Electric operates under cost of service regulation, whereby electricity rates are intended to recover the cost of providing the service. Thus the next step in this study is to use the load data to estimate the cost of providing the service.

Using the metered coincident and group non-coincident peak loads shown in the Table 2-4, the following two tables show how a revenue to cost ratio was estimated for each farm type, using the results of the 2017 Cost Allocation Study. To do the calculations, 2017 costs are allocated to the metered loads as if those loads had been served in 2017 (see Table 3-3), and the corresponding revenue that would have been collected in 2017 is based on the loads being billed on the March 1, 2017 Rural Residential Rate (see Table 3-2). To provide context for the calculations, the 2017 Cost Allocation Study results for the Residential Rate are included in the tables.

The Cost Allocation Study allocates costs to the various rate classes by means of a three step process. These steps are:
'1. Functionalization – All of the Company's costs for a year are assigned to one or more of the functions involved in the supply of electricity to customers; e.g. generation, transmission, substations, distribution lines, metering, billing.

‘2. Classification – The costs so assigned are then classified as one or more of the following:

- Customer – These are costs related to the number of customers on the system
- CP (Coincident Peak) Demand – These are costs related to the size of the annual system peak load, which include generating capacity and the transmission system through to distribution substations.
- NCP (Non-Coincident Peak) Demand – These are costs related to the size of the maximum load for a particular class of customers, which may not occur at the same time as the annual system peak load. These costs include a portion of primary (distribution) lines, distribution transformers and secondary lines.
- Energy – These are costs related to the number of kWh supplied.

‘3. Allocation – The classified costs are allocated to the various rate classes based on:

- For Customer costs, the numbers of customers in each rate class.
- For CP Demand costs, the load of each rate class at the time of annual system peak.
- For NCP Demand costs, the maximum load for each rate class as a percentage of the total of the maximum loads for all the rate classes.
- For Energy, the amount of kWh used by each rate class.

For Maritime Electric’s 2017 Cost Allocation Study, the results of the Functionalization and Classification steps are summarized in the table below. The unit costs shown can be applied to distribution system customer loads to allocate estimated costs for serving those loads in 2017.

Table 3-1: Unit costs (from 2017 Cost Allocation Study)

- Customer related	295	$ / yr
- CP Demand related	184.46	$ / kW-yr
- NCP Demand related	53.80	$ / kW-yr
- Energy related	83.00	$ / MWh

2019-10-10	Table 3-2: ESTIMATED REVENUE ALLOCATION FOR INDIVIDUAL FARM TYPES						
	(based on 2017 Cost Allocation Study)						
March 1, 2017 Residential Rate charges:				2017 total number of bills			
- Urban monthly service chge	24.57	$ / month		Urban		303,682	
- Rural monthly service chge	26.92	$ / month		Rural		408,486	
- First 2,000 kWh monthly	0.1396	$ / kWh					
- Second block energy	0.1108	$ / kWh					
	Residential for 2017			Jul 2018 to Jun 2019 hourly metered data			
				50	30	3	4
	Year round	Farms		Potato farms	Dairy farms	Hog farms	Poultry farms
Sales data:							
- annual sales (MWh)	505,169	52,322		6,036	4,571	1,812	444
First block MWh	466,014	23,545		1,043	720	72	95
Second block MWh	39,155	28,777		4,993	3,851	1,740	349
- average bills per month	57,286	2,094		50	30	3	4
Application of Rate ($ x 1,000):							
- service charges	17,781	676		16	10	1	1
- first block energy	65,056	3,287		146	101	10	13
- second block energy	4,338	3,189		553	427	193	39
- estimated revenue as billed	87,175	7,152		715	537	204	53
Revenue as billed	86,682	7,115		711	534	203	53
Less ECAM	1,226	127		15	11	4	1
Revenue as reported	85,456	6,988		696	523	198	52
Less rate of return adjustment	1,622	122		19	15	6	1
Plus weather normalization	26	2		0	0	0	0
Base (allocated) revenue	83,860	6,868		677	508	193	50

Table 3-3: ESTIMATED REVENUE TO COST RATIOS FOR INDIVIDUAL FARM TYPES
(Based on 2017 Cost Allocation Study)

	Unit costs (from 2017 Cost Allocation Study)		Potato farms	Dairy farms	Hog farms	Poultry farms	Year round Residentl for 2017
Jul 2018 to Jun 2019 metered farm data:							
- Number customers			50	30	3	4	57,286
- Coincident Peak Demand		(kW)	1,095	789	187	53	131,478
- Group Non Coincident Peak Demand		(kW)	1,616	730	260	80	161,888
- Energy		(MWh)	6,036	4,571	1,812	444	505,169
Allocated costs ($ x 1,000):							
- Customer related	295	$ / yr	15	9	1	1	16,915
- CP Demand related	184.46	$ / kW-yr	202	146	34	10	24,253
- NCP Demand related	53.80	$ / kW-yr	87	39	14	4	8,710
- Energy related	83.00	$ / MWh	501	379	150	37	41,928
			805	573	200	52	91,805
Allocated revenues for 2017 ($ x 1,000)			677	508	193	50	83,860
Estimated revenue to cost ratios (%)			84	89	96	97	91

The above table shows different revenue to cost ratios for the different farm types, with hog farms and poultry farms having the highest values. However, it is important to keep in mind that the above table is based on the NCP for the farms as a group; i.e. it takes into account the diversity between the loads of the four types of farms, which is appropriate when the farms are considered as a group. If the individual NCP's for each farm type (shown in Table 2-5) were used instead, the revenue to cost ratios would be as follows:

- 84 % for potato farms (the same)
- 87 % for dairy farms (lower)
- 93 % for hog farms (lower)
- 92 % for poultry farms (lower)

To provide an overall revenue to cost ratio for farms served under the Residential Rate, we need a weighted average of the revenue to cost ratios for the individual farm types. This is shown in the table below. The weighting is based on the estimated total annual electricity usage by each farm type. The result is a revenue to cost ratio of 86 %, which is higher than the 82 % result in the 2017 Cost Allocation Study, but still below a minimum acceptable value of 90 % in the short term and 95 % for the long term.

Table 3-4: ESTIMATED REVENUE TO COST RATIO FOR RESIDENTIAL RATE FARI

	Estimated 2017 electricity usage			For Residential Rate usage	
Farm sector	From Table 2-2 Total (GWh)	For storage facilities under GS or SI rates (GWh)	Estimated Residential Rate usage (GWh)	Estimated revenue to cost ratios (%)	Weighted average revenue to cost ratio (%)
Potato	39.4	8.0	31.4	84	54.6
Dairy	11.7	-	11.7	89	21.6
Hog	2.3	-	2.3	96	4.6
Poultry	1.9	-	1.9	97	3.8
Cereal crops	2.0	1.0	1.0	84	1.7
	57.3	9.0	48.3		86.3

Storage facilities served under the General Service and Small Industrial Rates are not part of a farm. They provide storage as a service to others.

Storage for cereal crops was assigned the same revenue to cost ratio as potato warehouses because of assumed similarity of operations.

‘4. Alternatives to the Residential Rate for large farms

As a start to considering alternatives to the Residential Rate for large farms, the following table shows estimated average increases in bills for two scenarios; 1) staying on the Residential Rate after the second energy block is eliminated, and 2) moving to the Small Industrial Rate. The 2017 allocated revenue for the two scenarios is calculated in the same way as shown in Table 3-2 for the March 1, 2017 Residential Rate. The table shows that the increases in bills would be smaller under the Small Industrial Rate, but still significant.

Table 4-1: IMPACT IF RESIDENTIAL SECOND BLOCK ELIMINATED OR MOVED TO SMALL INDUSTRIA						
		50	30	3	4	
		Potato farms	Dairy farms	Hog farms	Poultry farms	Weighted average
2017 allocated cost (from Table 3-3)	($)	805	573	200	52	
2017 Residential Rate						
- revenue (from Table 3-2)	($)	677	508	193	50	
- revenue to cost ratios	(%)	84	89	96	97	86
2017 Residential Rate - no second block						
- revenue	($)	820	619	242	60	
- revenue to cost ratios	(%)	102	108	121	116	105
- revenue increase over Residential	(%)	21	22	26	20	
2017 Small Industrial Rate						
- revenue	($)	818	594	214	62	
- revenue to cost ratios	(%)	102	104	107	119	103
- revenue increase over Residential	(%)	21	17	11	23	

The starting point for considering a separate rate for farms is Maritime Electric's existing Small Industrial Rate. The reasons for this are:

- The Small Industrial Rate would be the most appropriate of the Company's existing rates for large farming operations.
- The 2017 Cost Allocation Study estimated a revenue to cost ratio of 102 % for the Small Industrial Rate.

The table below is an analysis of the 2017 allocated costs for the farms July 2018 to June 2019 metered data, compared to the March 1, 2017 Small Industrial Rate charges. Customer costs are assumed to be recovered through the Demand charge, which is a reasonable simplification given that Customer costs are less than 2 % of the total allocated cost.

The result is a good match between the average allocated costs and the corresponding Small Industrial Rate charges, which indicates that the existing Small Industrial Rate would be appropriate for large farms. Thus, rather than have a separate rate for large farms, a more straightforward approach is to make farms eligible for service under the existing Small Industrial Rate.

2020-05-14	Table 4-2: COMPARISON OF FARMS ALLOCATED COST TO SMALL INDUSTRIAL RATE					
		(based on 2017 Cost Allocation Study)				
				Energy		Total
			First	Second		allocated
	Customer	Demand	Block	Block	Total	cost
			(first 100 kWh/kW-mo)			
2017 allocated costs for Jul 2018 to Jun 2019 loads:	($ x 1,000)				($ x 1,000)	($ x 1,000)
- 50 potato farms	15	289			501	805
- 30 dairy farms	9	185			379	573
- 3 hog farms	1	49			150	200
- 4 poultry farms	1	14			37	52
total	26	536			1,068	1,630
Jul 2018 to Jun 2019 billing determinants:		(kW-mo)	(MWh)	(MWh)	(MWh)	
- 50 potato farms	n/a	22,738	2,228	3,808	6,036	
- 30 dairy farms	n/a	15,385	1,539	3,032	4,571	
- 3 hog farms	n/a	4,698	470	1,342	1,812	
- 4 poultry farms	n/a	1,760	176	268	444	
total		44,581	4,413	8,450	12,863	
	Weighting	($ / kW-mo)	($ / kWh)	($ / kWh)	($ / kWh)	
- 50 potato farms	0.66	7.00	0.1478	0.0830		
- 30 dairy farms	0.25	6.58	0.1430	0.0830		
- 3 hog farms	0.05	5.35	0.1346	0.0830		
- 4 poultry farms	0.04	4.69	0.1231	0.0831		
- 2017 weighted average costs		6.72	0.1450	0.0830	0.0830	
March 1, 2017 Small Industrial Rate		($ / kW-mo)	($ / kWh)	($ / kWh)		
		7.46	0.1682	0.0844		

Notes: 1. Average 2017 cost for Demand includes Customer costs and an assumed 50 % of Demand costs.

2. Average 2017 cost for First Block Energy includes the Second Block Energy charge plus an assumed 50 % of Demand costs.

3. Table 4-1 shows a revenue to cost ratio of 103 % for large farms on the Small Industrial Rate.

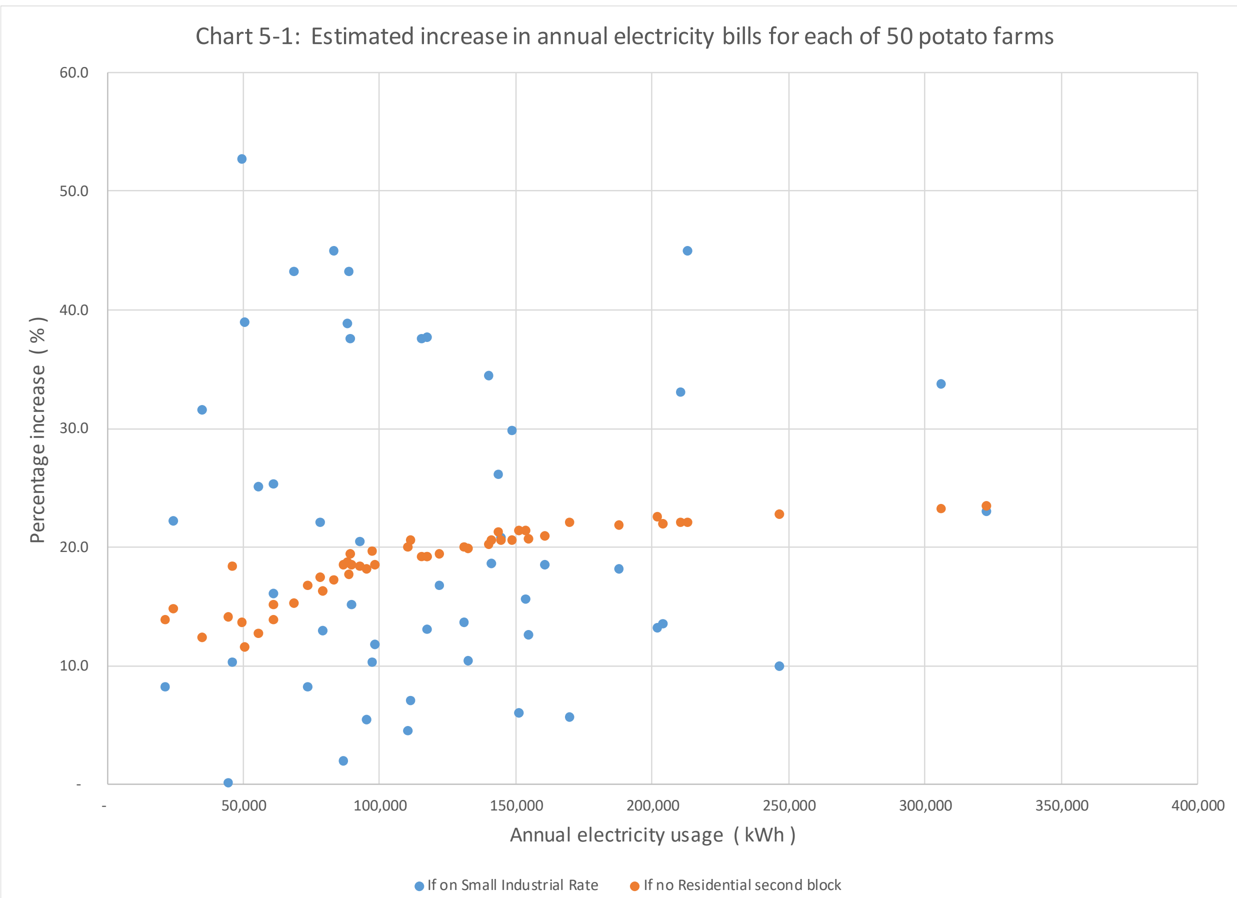
4. July 2018 to June 2019 billing determinants are for assumed service under Small Industrial Rate.

‘5. Transition of large farms to Small Industrial Rate

Table 4-1 showed estimated increases in electricity bills for the July 2018 to June 2019 usage for large farms had they been served under the March 1, 2017 Residential Rate with the second energy block eliminated and under the March 1, 2017 Small Industrial Rate, both as compared to the March 1, 2017 Residential Rate. The estimated increases are summarized in the table below.

	Table 5-1: ESTIMATED INCREASES IN ANNUAL ELECTRICITY BILLS (%)							
					50 Potato farms	30 Dairy farms	3 Hog farms	4 Poultry farms
If on 2017 Residential Rate - no second block					21	22	26	20
If moved to 2017 Small Industrial Rate					21	17	11	23

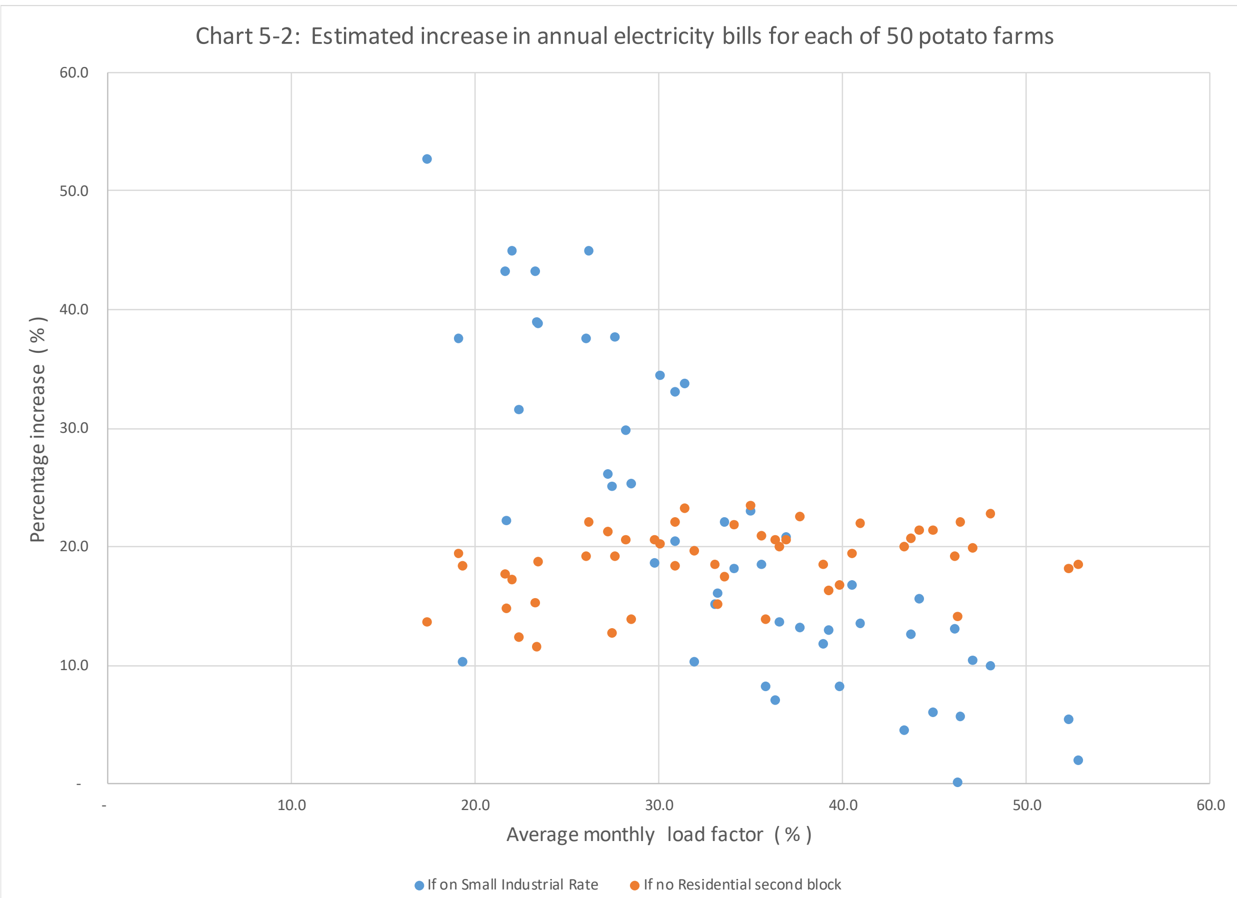
The increases in electricity bills in the above table are averages. There are significant variations above and below the average value for individual farms. The chart below shows the estimated increases for each of the 50 potato farms if on the Small Industrial Rate, as well as the estimated increases for the Residential Rate with the second energy block removed.



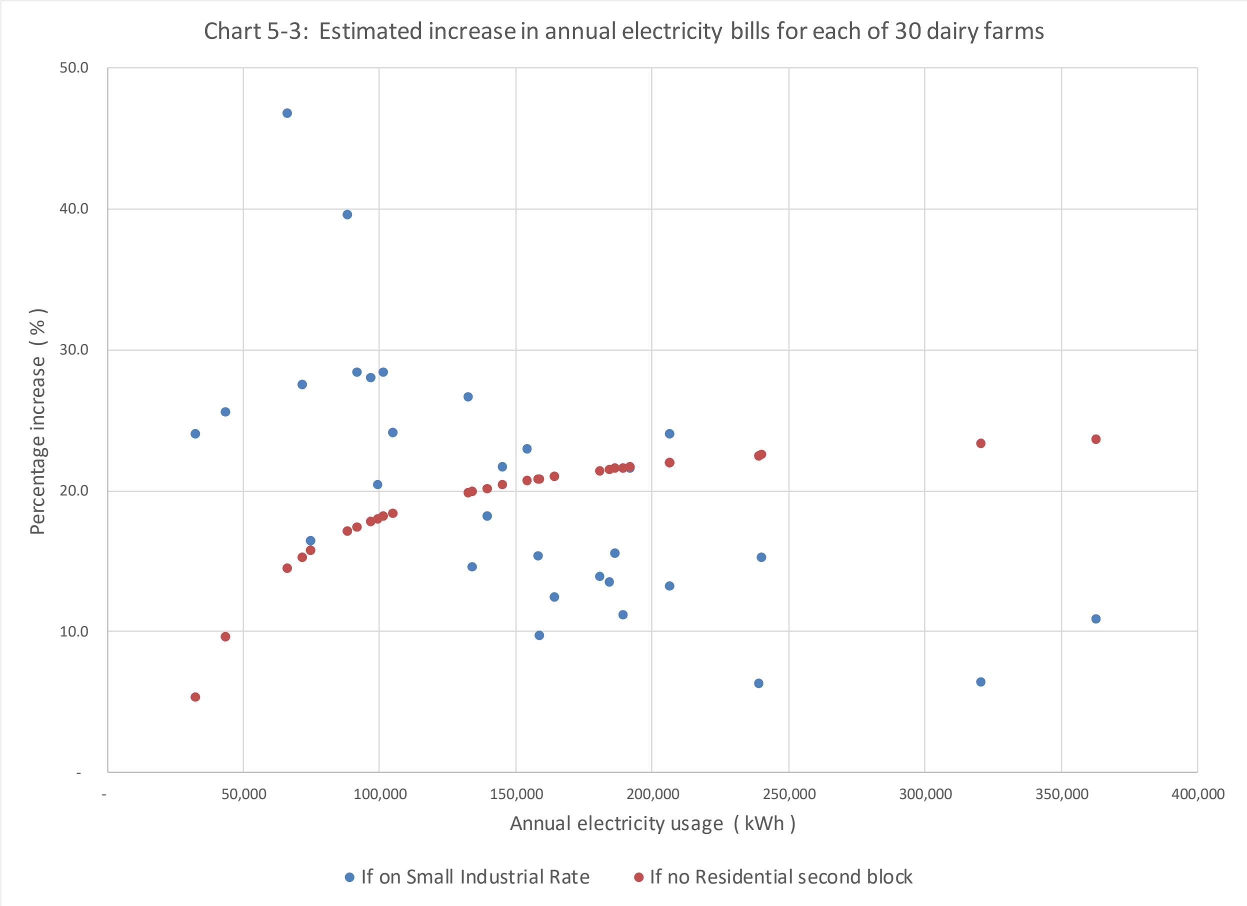
The chart shows a wide ranges on increases for individual farms. The chart indicates that when the second energy block is eliminated from the Residential Rate, approximately half of the 50 potato farms would experience a smaller increase by remaining on the Residential Rate as compared to moving to the Small Industrial Rate. If farms are given a choice between staying on the Residential Rate or moving to the Small

Industrial Rate, the maximum increase in bills would be 20 %, with the increase for most farms being between 10 % to 20 %.

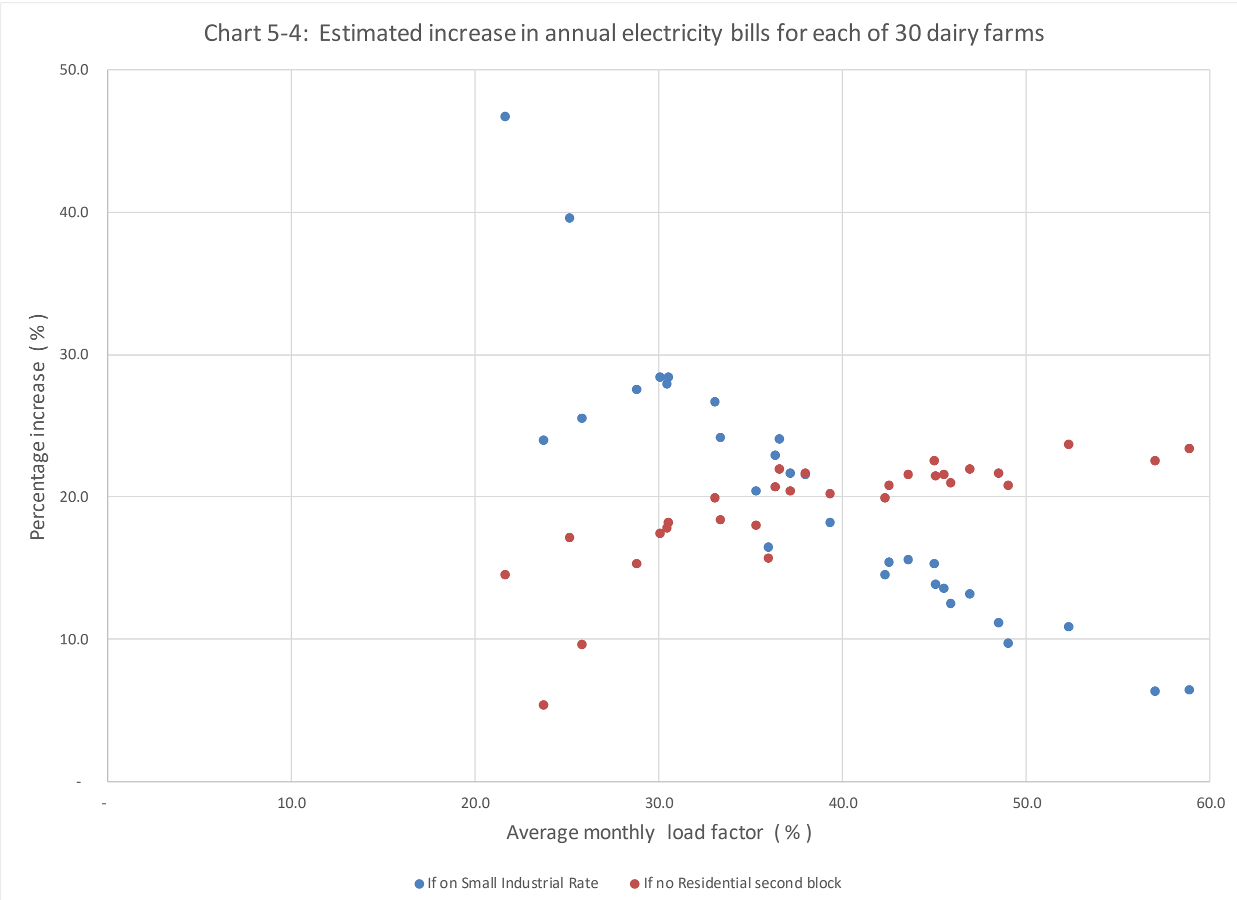
Much of the variation in increases associated with moving to the Small Industrial Rate is a function of load factor, as the next chart shows. Generally, the lower the load factor the higher the increase. The reason for this is that the lower the load factor, the larger the portion of kWh that are billed at the (higher) first block energy charge. Conversely, the higher the load factor, the larger the portion of kWh that are billed at the (lower) second block energy charge. A lower second block energy charge is appropriate for the Small Industrial Rate because the Rate has a demand charge, such that the Demand related costs are recovered through the demand charge and first energy block charge. To a good approximation only Energy related costs are incurred in supplying second block energy, and the second energy block charge is intended to recover only Energy related costs.



The next chart shows the estimated increases for the 30 dairy farms if on the Small Industrial Rate, as well as the estimated increases for the Residential Rate with the second energy block removed.



Similar to the potato farms, approximately half of the 30 dairy farms would experience a smaller increase by remaining on the Residential Rate after the second energy block is eliminated as compared to moving to the Small Industrial Rate. Also, the variation in increases associated with moving to the Small Industrial Rate is even more a function of load factor than for the potato farms, as the next chart shows.



'6. Transition considerations

Maritime Electric proposes that small farms should remain eligible for service under the Residential Rate, provided that at least half of the electricity usage is for a year-round occupied residence. This proposal is based on the following considerations:

- More than half of the 2,200 Residential Rate accounts identified as farms have no second block energy usage, so they will not be affected by the elimination of the second block energy charge.
- It will help to support the tradition of the family farm in PEI. It appears that there is a growing interest in organic farming practices, in some cases on a small scale.
- It would be consistent with one of the provisions of the existing Residential Rate, under which a Residential Rate customer may operate a business from their home, provided that the electricity usage for the business does not exceed half of the total usage.

The proposal to make farms eligible for service under the Small Industrial Rate is intended for larger farms. A requirement for eligibility of service under the Small Industrial Rate would be that the customer is a bona fide farmer, as per the designation as used by the Province of PEI for eligibility for farm land assessment and marked gasoline and marked diesel oil permits (the main criterion is for the individual or corporation to own a farm and be earning at least $ 10,000 or 25% of their gross annual income from farming). Also, to be eligible for the Small Industrial Rate, electricity usage would have to be for a facility that is an integral part of a bona fide farming operation. Thus, for example, a stand-alone potato warehouse owned by a bona fide farmer would be eligible for service under the Small Industrial Rate as long as at least 50% of the product being stored was grown on the owner's farmland.

Many of the farm accounts that would move to the Small Industrial Rate include domestic usage, with the farm operations and house being served from one meter. Maritime Electric proposes that this arrange be grandfathered for existing accounts. For new accounts applying for service under the Small Industrial Rate, there would be a requirement to separate farm operations from domestic usage, with the farm operations served under the Small Industrial Rate and the house served under the Residential Rate.

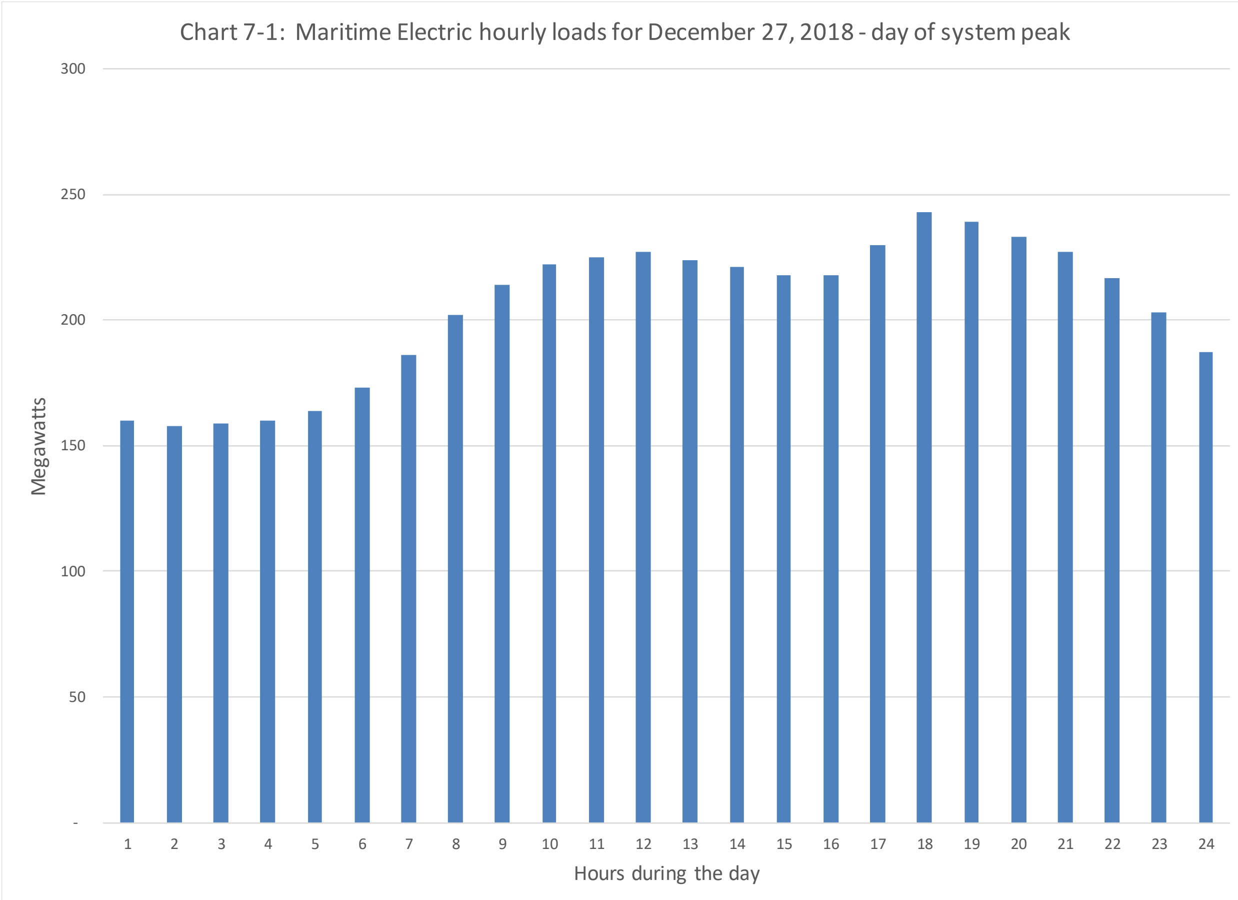
Still to do – provide an estimate of numbers of farms and associated electricity usage that would be moved to the Small Industrial Rate.

'7. Potential for a Time of Use (TOU) rate for farms

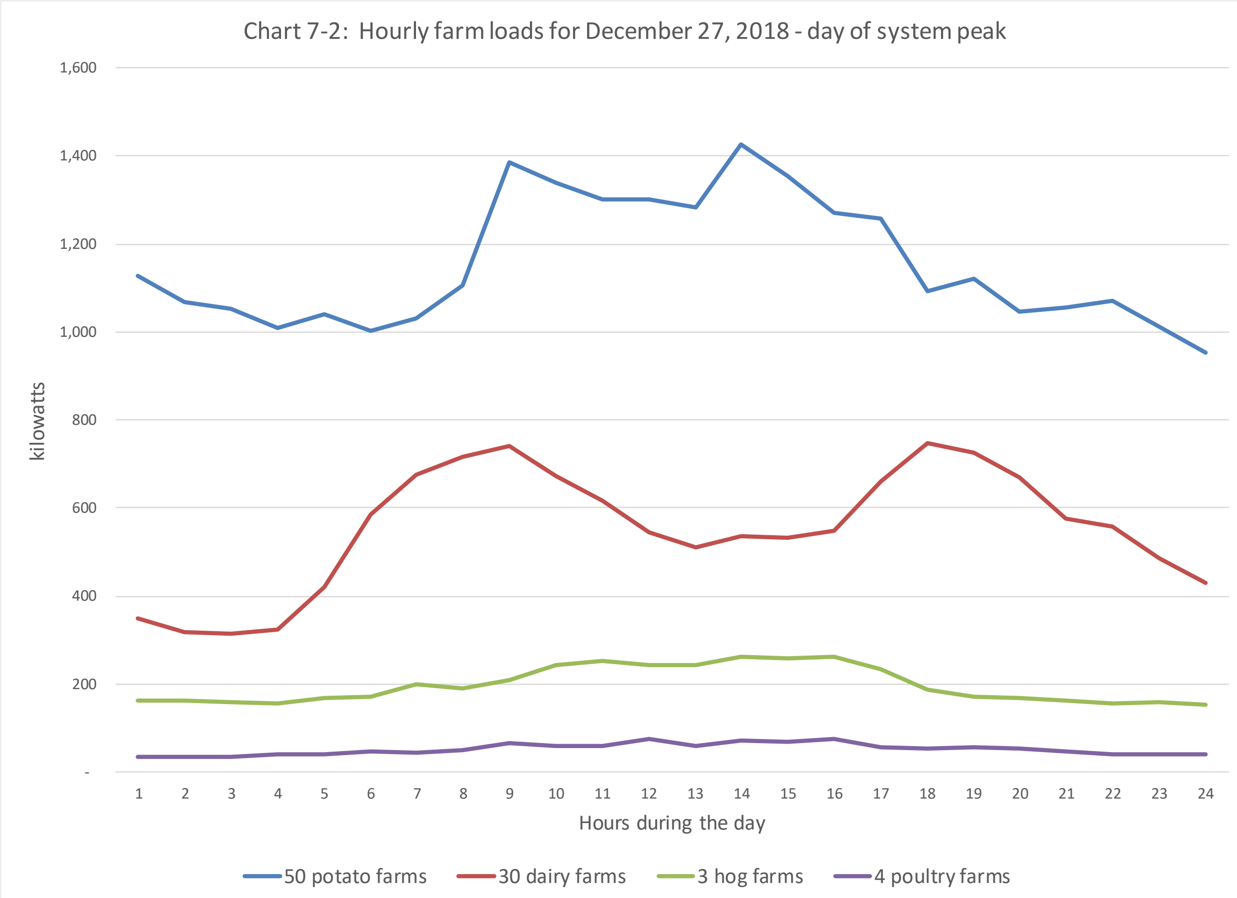
The main inputs to a business case assessment for a TOU rate are:

- The amount of load that could be shifted from on-peak to off-peak
- The difference between the cost of service during on-peak versus off-peak
- The cost of implementing and administering a TOU rate

<u>Potential to shift load</u>
The following chart shows the Maritime Electric hourly system loads for December 27, 2018, the day of the annual peak. The peak load occurs for the hour ending 18:00.



The following charts show the hourly loads for each of the four farm types for the day of the annual system peak load.

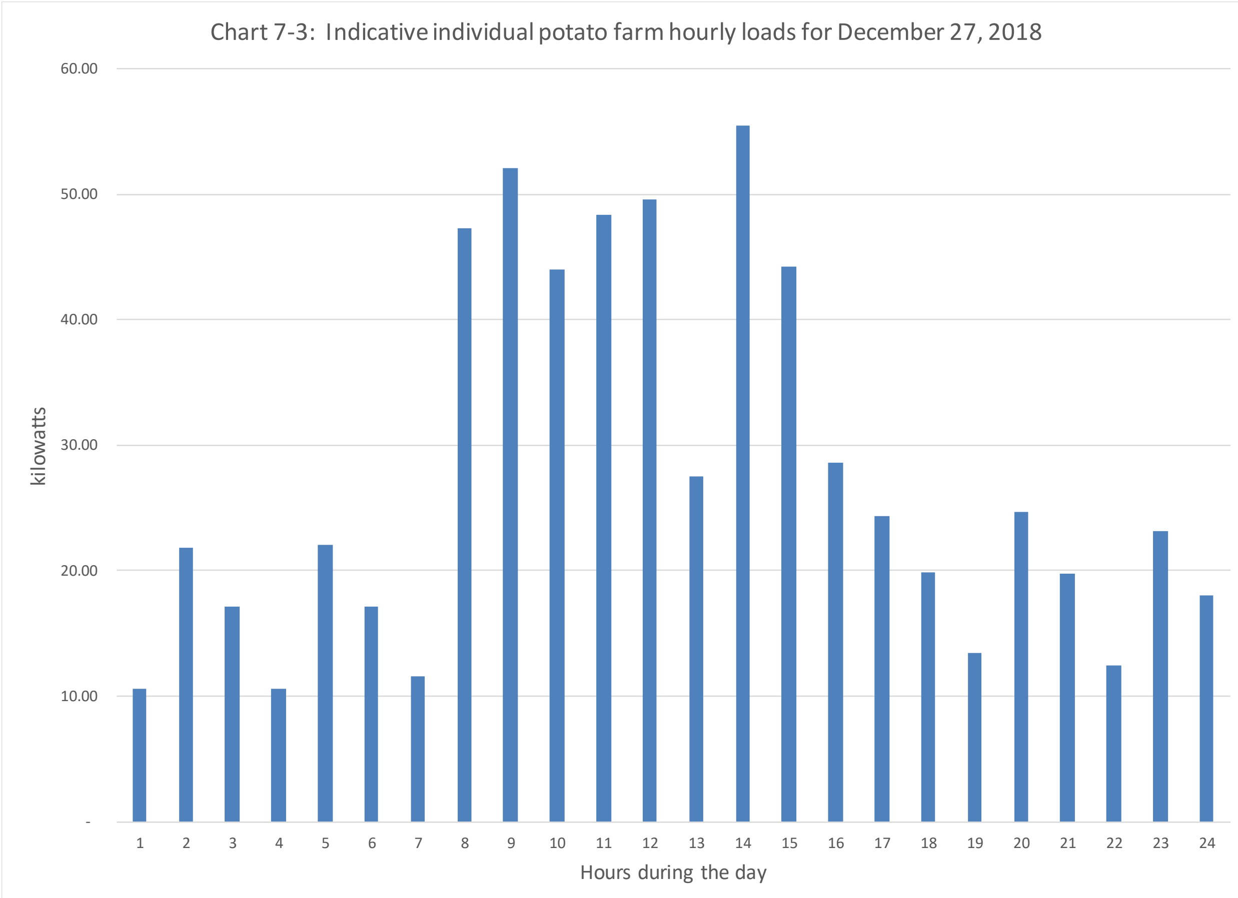


For potato, hog and poultry farms, the chart shows that the highest loads occur during the middle of the day, and by 18:00, the hour of the system peak load, the loads for these three farms types have declined from their mid-day values. The hourly load pattern for the dairy farms shows peaks for the traditional morning and evening milking times.

An examination of the daily load pattern for individual farms shows that there is some potential for load shifting. For potato farms, the main opportunity appears to be in the cycling on and off of fans. The following chart for an individual potato farm is indicative. It shows higher loads during the middle of the day, superimposed on two loads that appear to operate throughout the day:

- A constant load of approximately 11 kW
- A fan load of approximately 11 kW that is on for 50 % of the time – 1.5 hours on followed by 1.5 hours off

The potential for this potato farm to reduce load at system peak is estimated as 9 kW, which is the difference between the load for the hour ending 18:00 (20 kW) and the minimum load for the day (11 kW for the hour ending 4:00).



A similar analysis of the hourly loads for December 27, 2018 for all 50 potato farms shows a combined potential of 335 kW of load that could shifted off system peak for 34 of the farms, while the other 16 farms have hourly loads that are more or less constant throughout the day.

For dairy farms potential opportunities to shift load away from the hour ending 18:00 are to reduce ventilation loads and delay milking until after 18:00. An analysis of the hourly loads for December 27, 2018 for all 30 dairy farms shows a combined potential of 264 kW of load associated with milking that could be shifted off system peak for 25 of the farms. The other 5 farms have hourly loads that are more or less constant throughout the day, possibly due to the use of robotic milking machines or such large herds that a milking session lasts for up to 5 to 6 hours or more.

The results of this analysis are summarized in the following table, along with the estimated annual cost saving if all the potential for load shifting by the 50 potato farms and 30 dairy farms were to be realized at the time of the annual system peak load. The cost saving is based on the coincident peak Demand related cost from the 2017 Cost Allocation Study.

Table 7-1: ESTIMATE OF SYSTEM PEAK LOAD COST SAVING WITH TIME-OF-USE RATE							
		For December 27, 2018					
		Load for hour ending 18:00	Potential to shift away from 18:00		2017	Potential cost saving at system peak load	
	Number of farms	(kW)	(kW)	Annual usage (MWh)	allocated cost ($)	($)	(%)
Potato farms:							
- with constant load	16	358	-	1,562	208,318		
- with varying load	34	736	335	4,474	596,682	61,794	10.4
subtotal	50	1,094	335	6,036	805,000		
Dairy farms:							
- minimal potential	5	71	-	647	81,105		
- with potential	25	717	264	3,924	491,895	48,697	9.9
subtotal	30	788	264	4,571	573,000		
Coincident peak Demand related cost (from 2017 Cost Allocation Study)						184.46	$ / kW-yr

The third main input to a business case assessment of a TOU rate for farms is the estimated cost to implement and administer the TOU rate. The following table shows the estimated costs and the resulting benefit to cost ratio for a TOU rate, based on smart (or TOU capable) meters being installed at all 50 of the potato farms and all 30 dairy farms. The table shows that with an assumed realization of 50 % of the potential for load shifting off system peak, the benefit to cost is approximately 5 to 1, which indicates a very positive business case for a TOU rate for farms.

Table 7-2: BENEFIT COST ANALYSIS OF TIME-OF-USE RATE FOR FARMS			
	Potato farms ($)	Dairy farms ($)	Total ($)
Per unit incremental annual costs to implement TOU rates:			
- financing cost for a smart meter	10	10	
- meter reading and billing per meter	120	120	
Number of farms	50	30	80
Incremental annual costs to implement TOU rates:			
- financing cost for smart meters	500	300	800
- meter reading and billing	6,000	3,600	9,600
total	6,500	3,900	10,400
50 % of estimated annual system peak load cost saving from Table 7-1	30,897	24,349	55,246
Benefit to cost ratio (for 50 % participation)	4.8	6.2	5.3

'8. Statistical considerations

The purpose of this section is to provide an indication of how accurately the results from the sample of 87 farms are representative of the total PEI farm population for those four farm types.

The table below shows two perspectives on the sample size:

- The total number of farms in PEI for each of the four farm types that were sampled, as well as the sample size for each farm type.
- The metered kWh usage by sample as a percent of the estimated total kWh usage for each farm type.

Table 8-1: Sample size in perspective

Farm types populations and sample sizes

	Potato	Dairy	Hog	Poultry
Total number of farms	300	161	13	15
Sample size	50	30	3	4

Notes: 1. The total number of potato farms is approximate

2. The total number of dairy, hog and poultry farms is from the gov.pe.ca website - Government/Agriculture and Land

Farm types kWh usage and sample kWh usage

	Potato	Dairy	Hog	Poultry
Electricity usage for 2018 (GWh):				
- metered usage by sample	5.4	4.5	1.8	0.4
- less domestic usage by sample	0.3	0.2	0.0	0.0
- estimated farm usage by sample	5.1	4.3	1.7	0.4
- estimated total usage by farm sector	36.5	12.1	2.2	1.9
Sample usage as % of total usage (%)	14	36	79	21

Notes: 1. Estimation of total usage by farm sector for 2018 is similar to calculation for 2017 shown in Table 2-2

2. Installation of hourly data meters will be done at 4 additional poultry farms, which will increase the kWh usage of the sample to 45 % of the estimated usage by all poultry farms

Normally the sample size would be determined at the start of a study, based on the desired level of accuracy for the results. This was not done for this study, but the same statistical analysis can be applicable, assuming that the meters are installed at a representative sample of the total population.

Rather than being randomly selected, the farms selected for the study were identified on the basis of:

- Being among the larger farms in terms of electricity usage. It is the larger farms that will be most affected by elimination of the Residential second energy block, and thus it is the larger farms that are most relevant to the study.

- Having existing (i.e. prior to the study) meters that could provide monthly demand as well as energy readings. The thinking was that this would provide monthly demand readings for 2017, the latest year for which a Cost Allocation Study would be available, which might enable greater use of the 2017 Cost Allocation Study results. (To reduce the number of different meter types to stock, the Company installs a meter with demand reading capability on all services greater than 200 Amps in size, even if the demand reading will not be used for billing purposes. This is the case for some of the larger farms on the Residential Rate, which does not have a demand charge.)

The number of farms thus selected for the study was assumed to be large enough, either in numbers or in terms of the portion of total electricity usage by a particular farm type, to provide results within an acceptable level of statistical accuracy.

For the dairy farm sector, their load at system peak for 2018 (for the hour ending 18:00 on December 16) was estimated as 2.2 MW. Based on a stratification analysis, the 2.2 MW has an accuracy within +/- 12.5 % with 90 % confidence (i.e. 9 times out of 10).

'9. Conclusions

Based on hourly metered load data for 87 large farms, the estimated 2017 revenue to cost ratio for farms is 86 %. This is greater than the 82 % estimate in the 2017 Cost Allocation Study, but still less than the minimum acceptable level of 90 %.

Making farms eligible for service under the Small Industrial Rate will mitigate the impact on electricity bills for large farms due elimination of the second energy block in the Residential Rate. Of the 87 large farms for which hourly metered data was collected, approximately half would experience smaller increases by moving to the Small Industrial Rate when the Residential second energy block is eliminated. On the Small Industrial Rate their bill increases would be in the 10 % to 20 % range, as compared to increases of 20 % to 25 % under the Residential Rate with no second energy block.

The other half of the 87 large farms would experience smaller increases by staying on the Residential Rate. They would experience bill increases in the 10 % to 20 % range after the second energy block is eliminated. However, for both groups these are still large increases. A phase in over several years is recommended, with increases limited to no more than 5 % in any one year.

There is potential for a Time of Use rate. Many of the large farms could save an estimated 10 % on average on their bills under a TOU rate. The saving would come from lower demand charges by shifting load away from the 4:30 p.m. to 7:30 p.m. time period, which is when the annual system peak load occurs. This time period is also when the majority of Maritime Electric's monthly peak loads occur.

APPENDIX D

Potential General Service Subclasses

Table D-1

Analysis by Demand Strata

2017 data	Demand stratum kW range	avg annual # of bills (cust proxy)	Sum of monthly kW demands	Annual first block energy kWh	Annual second block energy kWh	Average kW demand/cust	Potential class composition	Average kWh total/cust	Number of customers in class	Average LF
Annual	[0]	5,286	-	52,909,720	1,330,153	-	Small General	10,262		-
	[0.1-2.5]	105	1,642	341,348	13	1.3	Small General	3,254		28%
	[2.6-5.0]	96	4,382	950,507	921	3.8	Small General	9,911		30%
	[5.1-7.5]	102	7,720	1,712,887	580	6.3	Small General	16,868		30%
	[7.6-10.0]	124	13,108	3,150,502	96,472	8.8	Small General	26,238		34%
	[10.1-12.5]	136	18,485	4,564,752	63,236	11.3	Small General	33,946		34%
	[12.6-15.0]	140	23,147	5,532,767	311,112	13.8	Small General	41,892		35%
	[15.1-20.0]	248	51,990	12,039,009	2,391,289	17.5	Small General	58,304	6,235	38%
	[20.1-50.0]	625	227,684	35,300,768	34,304,064	30.4	General	111,397		42%
	[50.1-100.0]	186	153,169	11,203,635	40,335,301	68.7	General	277,215		46%
	[100.1-150.0]	64	94,037	4,161,770	29,011,835	123.1	General	521,051		48%
	[150.1-250.0]	45	99,193	3,138,200	32,565,678	185.1	General	799,341	919	49%
	[250.1-up]	36	221,552	2,173,667	99,577,298	508.1	Large General	2,800,485	36	63%

Table D-2

Analysis by Energy Strata

	Energy Stratum kWh	avg annual # of bills (cust proxy)	Annual Energy kWh	Avg kWh per customer	Potential class composition	Number of customers in class	Class Energy kWh
2017 annual	[< 0] (Adjustme	0	(956,604)				
	[0]	251	-				
	[1-50]	618	159,731	258	Small General		
	[51-100]	382	343,754	901	Small General		
	[101-250]	815	1,664,587	2,044	Small General		
	[251-500]	917	4,048,085	4,414	Small General		
	[501-1000]	1075	9,293,733	8,649	Small General		
	[1001-1500]	629	9,272,634	14,736	Small General		
	[1501-2500]	703	16,468,728	23,426	Small General		
	[2501-5000]	754	31,940,272	42,375	Small General	6,143	73,191,524
	[5001-10000]	492	41,440,517	84,157	General		
	[10001-15000]	197	28,786,169	145,999	General		
	[15001-20000]	90	18,597,095	206,252	General		
	[20001-50000]	175	64,329,579	367,773	General		
	[50001-100000	59	48,014,131	812,651	General	1,014	201,167,491
	[100001-up]	34	102,236,635	3,021,772	Large General	34	102,236,635

APPENDIX E

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Mr. Boutilier is a Professional Engineer with broad management experience in the electric energy industry, particularly in the areas of strategic analysis, planning and development, load forecasting, cost-of-service regulation, pricing strategy, rate design, revenue management, marketing, customer relationships and negotiations, and new business development. He has presented to international audiences regarding electricity forecasting and rate design, been instrumental in the design, customer and regulatory approval, and implementation of innovative industrial rates, and served as Nova Scotia Power Incorporated's (NSPI) witness on numerous occasions before the Nova Scotia Utility and Review Board (NSUARB). Mr. Boutilier possesses strong analytical, organizational, communication and management skills and has a successful record of planning, design, implementation and management of teams and systems.

During his employment career, Mr. Boutilier held a variety of positions within NSPI and its parent company, Emera Inc, including Engineering Systems Analyst, Load Forecast Engineer, Rates and Forecasting Manager, Manager of Pricing Strategy, Manager Industrial Marketing, Director of Marketing and Sales (acting), Director of Regulatory Affairs and Director of Business Development Support Services for Emera. Prior to joining NSPI, Mr. Boutilier was involved in productivity improvement, power generation and management projects at International Nickel Company (INCO) in Sudbury, Ontario.

Mr. Boutilier played a lead role in the development and regulatory support of NSPI's applications before the NSUARB regarding topics such as General Rate Applications, Innovative Rate Design, and Demand Side Management. He served as principle liaison and negotiator between NSPI and its large industrial customers regarding the design and operation of dynamic pricing and demand response rates.

Prior to retiring from Emera, Mr. Boutilier provided Regulatory consultation to, and assisted in developing and strengthening Emera's business holdings and interests in Caribbean energy projects, including the investigation and installation of renewable power opportunities.

Since 2014, Mr. Boutilier has been self-employed in providing utility consulting services.

Mr. Boutilier holds Bachelor of Science (Dalhousie University, Halifax, 1978) and Bachelor of Industrial Engineering degrees (Technical University of Nova Scotia, Halifax, 1980). His professional development and training includes cost of service (NARUC; National Association of Regulatory Utility Commissioners, New Mexico), marginal cost based rate design (NERA, California), management skills (McGill University, Montreal), and courses regarding applied business and electric load forecasting.

Mr. Boutilier is a registered professional engineer in the province of Nova Scotia. He served as a member of the Canadian Manufacturers and Exporters Energy Committee for Nova Scotia, the Load Forecasting Subcommittee of the Canadian Electrical Association, and as an elected member and Vice Chair of the Board of Trustees with the Halifax Regional School Board.

NSPI/Emera Details (1984-2012)

- IT Systems Analyst; Engineering projects. Responsible for assisting engineering staff with project tracking, automation and programming of computerized business solutions.
- Load Forecaster. Responsible for the development, operation and maintenance of systems, databases and software to prepare NSPI's annual load forecasts. Included statistical and economic analysis and modeling, end-use models, weather normalization procedures, large customer planning and reporting.
- Manager Rates and Regulations. Managed staff responsible for cost of service modelling, rates and regulations approval, application and management.
- Manager Industrial Market. Responsible for developing and maintaining NSPI business relationships with large industrial customers, including marketing programs and innovative rate concepts. Developed and supported approval of new rate developments before UARB.
- Director Regulatory Affairs. Managed staff responsible for maintaining liaison between NSPI and UARB, including correspondence, management of scheduled reports and filings, management of general rate applications, serving as NSPI's witness before the UARB on several occasions.
- Director Business Development Support. Assisted Emera in preparing external business development relationships and supporting analysis regarding a variety of utility projects involving rate design, geothermal opportunities and business growth.

Consulting Projects (2013-present)

Provided consulting services and advice to Nova Scotia Power Inc. regarding Efficiency Nova Scotia's Demand Side Management program plans. Served as a witness before the NSUARB on behalf of NSPI.

Provided Emera Inc. with consulting advice regarding regulatory aspects of a Due Diligence Review regarding a potential utility acquisition.

Provided regulatory and rate design services and advice to Grand Bahama Power Company with respect to their 2016 Regulatory planning and Filing. Introduced new industrial tariff.

Provided consulting services and advice for Emera Caribbean Inc. regarding its geothermal drilling procurement project for a Caribbean island nation. Assisted in the development and administration of the RFP process from design to selection of contractor.

Provided regulatory and rate design consultation on potential new utility end-use marketing programs.