WHENEVER. WHEREVER.
We'll be there.

NEWFOUNDLAND POWER
A FORTIS COMPANY

DELIVERED BY HAND

June 1, 2018

Board of Commissioners
of Public Utilities
P.O. Box 21040
120 Torbay Road
St. John's, NL   A1A 5B2

Attention: G. Cheryl Blundon
Director of Corporate Services
and Board Secretary

Ladies and Gentlemen:

Re: 2019/2020 General Rate Application

1. Background

In Order No. P.U. 18 (2016), the Board ordered, amongst other things, that Newfoundland Power Inc. ("Newfoundland Power" or the "Company") file its next general rate application with a 2019 test year on or before June 1, 2018 unless otherwise directed by the Board.

On November 21, 2017, the Board directed Newfoundland Power to file a report relating to its Rules and Regulations no later than April 13, 2018. The Board stated that Newfoundland Power's next general rate application, due to be filed by June 1, 2018, would provide an opportunity for a full review of the issues contained in the report. This report was filed with the Board on April 12, 2018.

2. The Filing

Enclosed with this letter are the original and 11 copies of a general rate application for a review of Newfoundland Power's 2019 and 2020 costs and customer rates (the "Application").

The Application and pre-filed supporting materials have been provided in two volumes set out as follows:

Volume 1: ***Application, Company Evidence and Exhibits:*** *this Volume contains this letter, the formal Application, the Company Evidence and supporting Exhibits.*

Newfoundland Power Inc.
55 Kenmount Road • P.O. Box 8910 • St. John's, NL A1B 3P6
PHONE (709) 737-5364 • FAX (709) 737-2974 • **khopkins@newfoundlandpower.com**

Volume 2: ***Supporting Materials:*** *this Volume contains the supporting forecasts, reports and studies prepared by the Company and the expert cost of capital evidence of Mr. James Coyne of Concentric Energy Advisors Inc.*

3. Application Proposals

General

The Application proposes that the Board approve an overall average increase in Newfoundland Power's current customer rates of approximately 1.2%, with effect from March 1, 2019.

The proposed overall average increase in rates is primarily the result of 3 changes in Newfoundland Power's cost of service. A mixture of changes in the Company's costs, ranging from increased operating costs to lower employee future benefits expense, account for an increase in revenue required from customer rates of approximately 0.7%. Rebalancing 2019 and 2020 supply costs from Newfoundland and Labrador Hydro accounts for a decrease of approximately 0.7%. Finally, increasing Newfoundland Power's ratemaking return on equity for 2019 and 2020 accounts for an increase of approximately 1.2%.

Cost of Capital

The expert evidence filed with this Application indicates a fair return on equity for Newfoundland Power in 2019 and 2020 is 9.5% based upon a 45% common equity ratio. Further, it is proposed that the Board continue to refrain from the use of an automatic adjustment formula for setting the allowed rate of return on the Company's rate base, in years subsequent to 2020, given current financial market conditions.

Regulatory Accounting

The Application proposes that Newfoundland Power:

1. Adopt a change in its accounting practices regarding capitalization of pension expenses associated with Accounting Standards Update 2017-07 issued in 2017 by the Financial Accounting Standards Board; and

2. Amortize over the 2019 to 2021 period:
   a) an estimated $1.0 million in Consumer Advocate and Board hearing costs associated with the Application; and

   b) a forecast 2019 revenue surplus of approximately $919,000.

Customer Rates

Newfoundland Power is also proposing that the Board approve the addition of a new service offering for LED street and area lighting and a corresponding amendment to Clause II.3 of the Rate Stabilization Clause. This service offering is consistent with Canadian utility practice.

The rate changes proposed in the Application reflect the Company's most recent cost of service study.

The rates, tolls and charges proposed in the Application will result in an overall rate increase of 1.2%. The increases in proposed customer rates by class are as follows:

Rate Class	***Average Increase***
Domestic	1.2%
General Service 0-100 kW (110 kVA)	1.2%
General Service 110-1000 kVA	1.2%
General Service 1000 kVA and Over	1.2%
Street and Area Lighting	1.2%

Changes to the Basic Customer Charges for (i) unmetered, (ii) single-phase, and (iii) three-phase service in Rate #2.1 – General Service 0-100kW (110 kVA) are also proposed to more accurately reflect differences in the costs of providing such services.

4. Process & Related Matters

Newfoundland Power would be grateful if the Board would (i) give public notice of the Application, (ii) call a pre-hearing conference, and (iii) establish a schedule for the Application at its earliest convenient opportunity. This will permit the Application to be processed in a transparent and efficient manner consistent with the establishment of customer rates on March 1, 2019.

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PHONE (709) 737-5364 • FAX (709) 737-2974 • **khopkins@newfoundlandpower.com**

The Application has been forwarded directly to Newfoundland and Labrador Hydro and Mr. Dennis Browne, Q.C., the Consumer Advocate.

It is Newfoundland Power's intention to file an Adobe portable document format (pdf) copy of this filing within the next few days. Additional copies of the filing will be made available as required.

Newfoundland Power will also post a copy of the Application on its website at www.newfoundlandpower.com. In addition, copies will be made available for viewing at the Company's offices in Stephenville, Corner Brook, Grand Falls-Windsor, Gander, Clarenville, Burin, Carbonear, and St. John's. Finally, the Company also intends to give notice to all municipalities within its service territory of its proposal to introduce a new service offering for LED street and area lighting.

We trust the foregoing and enclosed are found to be in order. However, please feel free to contact the Company if you have any questions.

Yours very truly,

Kelly Hopkins
Corporate Counsel

Enclosures

c. Geoffrey Young (3 copies)
Newfoundland and Labrador Hydro

Dennis Browne, QC (3 copies)
Consumer Advocate

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B. EXPERT EVIDENCE

Cost of Capital: Mr. James Coyne, Concentric Energy Advisors, Inc.

IN THE MATTER OF the *Public Utilities Act*, R.S.N.L. 1990, Chapter P-47, as amended, (the "Act"); and

IN THE MATTER OF a general rate application (the "Application") by Newfoundland Power Inc. ("Newfoundland Power") to establish customer electricity rates for 2019 and 2020.

TO: The Board of Commissioners of Public Utilities (the "Board")

THE APPLICATION OF Newfoundland Power **SAYS THAT**:

A. Background:

1. Newfoundland Power is a corporation duly organized and existing under the laws of the Province of Newfoundland and Labrador, is a public utility within the meaning of the Act, and is subject to the provisions of the *Electrical Power Control Act, 1994*.

2. The Act provides that the Board has the general supervision of public utilities and requires, in effect, that a public utility submit for the approval of the Board the rates, tolls and charges for the service provided by the public utility and the rules and regulations which relate to that service.

3. In Order No. P.U. 18 (2016), the Board ordered Newfoundland Power to file its next general rate application no later than June 1, 2018 with a 2019 test year unless otherwise ordered.

4. In Order No. P.U. 18 (2016), the Board ordered, amongst other things, that the use of the automatic adjustment formula shall be suspended pending a further Order of the Board.

5. In Order P.U. No. 18 (2016), the Board approved, amongst other things, Newfoundland Power's use of the depreciation rates and methodology as recommended in the *2014 Depreciation Study* for the calculation of its depreciation expense with effect from January 1, 2016.

6. On November 21, 2017 the Board directed Newfoundland Power to file a report relating to its Rules and Regulations no later than April 13, 2018. The Board stated that Newfoundland Power's next general rate application, due to be filed by June 1, 2018, would provide the opportunity for a full review of the issues contained in the report. This report was filed with the Board on April 12, 2018.

B. Newfoundland Power Proposals:

7. Newfoundland Power proposes that the Board continue to refrain from the use of an automatic adjustment formula for setting the allowed rate of return on rate base for Newfoundland Power, in years subsequent to 2020, for the reasons set out in the evidence filed in support of the Application.

8. Newfoundland Power proposes that the Board approve a change in its accounting practices regarding capitalization of pension expenses associated with Accounting Standards Update 2017-07 issued in 2017 by the Financial Accounting Standards Board, as more fully described in the evidence filed in support of the Application.

9. Newfoundland Power proposes that the Board approve the amortization of the recovery of an estimated $1,000,000 in Board and Consumer Advocate costs related to the Application over a 34-month period commencing March 1, 2019 and ending December 31, 2021, as more fully described in the evidence filed in support of the Application. Newfoundland Power further proposes that Board and Consumer Advocate costs in excess of $1,000,000 be recovered through the Rate Stabilization Account.

10. Newfoundland Power proposes that the Board approve the amortization of a forecast 2019 revenue surplus of an estimated $919,000 over a 34-month period, commencing March 1, 2019 and ending December 31, 2021.

11. Newfoundland Power proposes that the Board approve an overall average increase in current customer rates of 1.2% with effect from March 1, 2019, based upon:

    (a) a forecast average rate base for 2019 of $1,146,293,000 and for 2020 of $1,179,357,000;

    (b) a rate of return on average rate base for 2019 of 7.47% in a range of 7.29% to 7.65% and for 2020 of 7.49% in a range of 7.31% to 7.67%; and

    (c) forecast revenue requirements from customer rates for 2019 of $661,467,000 and for 2020 of $664,118,000.

12. Newfoundland Power proposes that the Board approve the addition of a new service offering for LED street and area lighting and a corresponding amendment to Clause II.3 of the Rate Stabilization Clause for the reasons set out in the evidence filed in support of the Application.

13. Newfoundland Power proposes that the Board approve (i) rates, tolls and charges, as set out in Schedule A to the Application, and (ii) rules and regulations governing service, as set out in Schedule B to the Application, which result in average increases in proposed customer rates by class as follows:

Rate Class	***Average Increase***
Domestic	1.2%
General Service 0-100 kW (110 kVA)	1.2%
General Service 110-1000 kVA	1.2%
General Service 1000 kVA and Over	1.2%
Street and Area Lighting	1.2%

all to be effective for service provided on and after March 1, 2019, as more fully described in the evidence filed in support of the Application.

14. Newfoundland Power proposes that the Board approve changes in the Basic Customer Charges and Minimum Monthly Charges for (i) unmetered, (ii) single phase, and (iii) three phase service in Rate #2.1 – General Service 0-100 kW (110 kVA) to more accurately reflect differences in the costs of providing such service and for the reasons set out in the evidence filed in support of the Application.

C. Order Requested:

15. Newfoundland Power requests that the Board make an Order approving:

(a) pursuant to Section 80 of the Act, the continued suspension of an automatic adjustment formula as set out in paragraph 7 of the Application;

(b) pursuant to Sections 58 and 80 of the Act, the amortizations set out in paragraphs 9 and 10 of the Application;

(c) pursuant to Sections 70 and 80 of the Act:

(i) rates, tolls and charges as set out in Schedule A to the Application; and
(ii) rules and regulations governing service as set out in Schedule B to the Application.

all of which reflect paragraphs 11, 12, 13 and 14 of the Application, to be effective for service provided on or after March 1, 2019; and

(d) such further or other matters that appear just and reasonable on the evidence.

D. Communications:

16. Communication with respect to this Application should be forwarded to the attention of Liam P. O'Brien, and Kelly C. Hopkins, Counsel to Newfoundland Power.

DATED at St. John's, Newfoundland and Labrador, this 1st day of June, 2018.

NEWFOUNDLAND POWER INC.

Liam P. O'Brien and Kelly C. Hopkins
Newfoundland Power Inc.
P.O. Box 8910
55 Kenmount Road
St. John's, NL A1B 3P6

Telephone: (709) 737-5364
Telecopier: (709) 737-2974
Email : khopkins@newfoundlandpower.com
lobrien@curtisdawe.com

IN THE MATTER OF the *Public Utilities Act*, R.S.N.L. 1990, Chapter P-47, as amended, (the "Act"); and

IN THE MATTER OF a general rate application (the "Application") by Newfoundland Power Inc. ("Newfoundland Power") to establish customer electricity rates for 2019 and 2020.

AFFIDAVIT

I, Peter Alteen, Q.C., of St. John's in the Province of Newfoundland and Labrador, make oath and say as follows:

1. That I am President and Chief Executive Officer of Newfoundland Power.

2. To the best of my knowledge, information and belief, all matters, facts and things set out in this Application are true.

SWORN at St. John's
in the Province of Newfoundland and Labrador
this 1st day of June, 2018,
before me:

Barrister	**Peter Alteen**

NEWFOUNDLAND POWER INC.
RATE #1.1
DOMESTIC SERVICE

Availability:

For Service to a Domestic Unit or to buildings or facilities which are on the same Serviced Premises as a Domestic Unit and used by the same Customer exclusively for domestic or household purposes, whether such buildings or facilities are included on the same meter as the Domestic Unit or metered separately.

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments)

Basic Customer Charge:
Not Exceeding 200 Amp Service .... $16.23 per month
Exceeding 200 Amp Service .... $21.23 per month

Energy Charge:
All kilowatt-hours .... @10.736¢ per kWh

Minimum Monthly Charge:
Not Exceeding 200 Amp Service .... $16.23 per month
Exceeding 200 Amp Service .... $21.23 per month

Discount:

A discount of 1.5% of the amount of the current month's bill will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
RATE #1.1S
DOMESTIC SEASONAL - OPTIONAL

Availability:

Available upon request for Service to Customers served under Rate #1.1 Domestic Service who have a minimum of 12 months of uninterrupted billing history at their current Serviced Premises.

Rate:

The Energy Charges provided for in Rate #1.1 Domestic Service Rate shall apply, subject to the following adjustments:

Winter Season Premium Adjustment (Billing Months of December through April):
All kilowatt-hours .... @ 0.953¢ per kWh

Non-Winter Season Credit Adjustment (Billing Months of May through November):
All kilowatt-hours .... @ (1.297)¢ per kWh

Special Conditions:

1. An application for Service under this rate option shall constitute a binding contract between the Customer and the Company with an initial term of 12 months commencing the day after the first meter reading date following the request by the Customer, and renewing automatically on the anniversary date thereof for successive 12-month terms.

2. To terminate participation on this rate option on the renewal date, the Customer must notify the Company either in advance of the renewal date or no later than 60 days after the anniversary/renewal date. When acceptable notice of termination is provided to the Company, the Customer's billing may require adjustment to reverse any seasonal adjustments applied to charges for consumption after the automatic renewal date.

NEWFOUNDLAND POWER INC.
RATE #2.1
GENERAL SERVICE 0-100 kW (110 kVA)

Availability:

For Service (excluding Domestic Service) where the maximum demand occurring in the 12 months ending with the current month is less than 100 kilowatts (110 kilovolt-amperes).

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments)

Basic Customer Charge:
Unmetered .... $12.50 per month
Single Phase .... $20.50 per month
Three Phase .... $32.50 per month

Demand Charge:
$9.25 per kW of billing demand in the months of December, January, February and March and $6.75 per kW in all other months. The billing demand shall be the maximum demand registered on the meter in the current month in excess of 10 kW.

Energy Charge:
First 3,500 kilowatt-hours .... @ 10.640¢ per kWh
All excess kilowatt-hours .... @ 7.844¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 18.957 cents per kWh plus the Basic Customer Charge, but not less than the Minimum Monthly Charge. The Maximum Monthly Charge shall not apply to Customers who avail of the Net Metering Service Option.

Minimum Monthly Charge:

Unmetered .... $12.50 per month
Single Phase .... $20.50 per month
Three Phase .... $32.50 per month

Discount:

A discount of 1.5% of the amount of the current month's bill will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular Regulation 7(n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
RATE #2.3
GENERAL SERVICE 110 kVA (100 kW) - 1000 kVA

Availability:

For Service where the maximum demand occurring in the 12 months ending with the current month is 110 kilovolt-amperes (100 kilowatts) or greater but less than 1000 kilovolt-amperes.

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments)

Basic Customer Charge: .... $50.17 per month

Demand Charge:
$7.82 per kVA of billing demand in the months of December, January, February and March and $5.32 per kVA in all other months. The billing demand shall be the maximum demand registered on the meter in the current month.

Energy Charge:
First 150 kilowatt-hours per kVA of billing demand,
up to a maximum of 50,000 kilowatt-hours .... @ 9.004¢ per kWh
All excess kilowatt-hours .... @ 7.143¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 18.957 cents per kWh plus the Basic Customer Charge. The Maximum Monthly Charge shall not apply to Customers who avail of the Net Metering Service Option.

Discount:

A discount of 1.5% of the amount of the current month's bill will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular, Regulation 7(n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
RATE #2.4
GENERAL SERVICE 1000 kVA AND OVER

Availability:

For Service where the maximum demand occurring in the 12 months ending with the current month is 1000 kilovolt-amperes or greater.

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments)

Basic Customer Charge: .... $87.44 per month

Demand Charge:
$7.53 per kVA of billing demand in the months of December, January, February and March and $5.03 per kVA in all other months. The billing demand shall be the maximum demand registered on the meter in the current month.

Energy Charge:
First 75,000 kilowatt-hours .... @ 8.669¢ per kWh
All excess kilowatt-hours .... @ 7.071¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 18.957 cents per kWh plus the Basic Customer Charge. The Maximum Monthly Charge shall not apply to Customers who avail of the Net Metering Service Option.

Discount:

A discount of 1.5% of the amount of the current month's bill will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular, Regulation 7(n)], transformation [in particular, Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
RATE #4.1
STREET AND AREA LIGHTING SERVICE

Availability:

For Street and Area Lighting Service where the electricity is supplied by the Company and all fixtures, wiring and controls are provided, owned and maintained by the Company.

Monthly Rate: (Includes Municipal Tax and Rate Stabilization Adjustments)

	Sentinel/Standard	Post Top
High Pressure Sodium		
100W (8,600 lumens)	$17.24	$18.57
150W (14,400 lumens)	21.27	-
250W (23,200 lumens)	29.69	-
400W (45,000 lumens)	40.99	-
Light Emitting Diode		
LED 100 (7,500 – 10,500 lumens)	$15.85	-
LED 150 (13,000 – 16,000 lumens)	17.30	-
LED 250 (22,000 – 25,000 lumens)	22.11	-
LED 400 (43,500 – 46,500 lumens)	24.97	-
Special poles used exclusively for lighting service*		
Wood	$6.72	
30' Concrete or Metal, direct buried	9.58	
45' Concrete or Metal, direct buried	15.71	
25' Concrete or Metal, Post Top, direct buried	7.05	
Underground Wiring (per run)*		
All sizes and types of fixtures	$16.38	

* Where a pole or underground wiring run serves two fixtures paid for by different parties, the above rates for such poles and underground wiring may be shared equally between the two parties.

General:

Details regarding conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
CURTAILABLE SERVICE OPTION
(for Rates #2.3 and #2.4 only)

Availability:

For Customers billed on Rate #2.3 or #2.4 that can reduce their demand ("Curtail") by between 300 kW (330 kVA) and 5000 kW (5500 kVA) upon request by the Company during the Winter Peak Period. The Winter Peak Period is between 8 a.m. and 9 p.m. daily during the calendar months of December, January, February and March. The ability of a Customer to Curtail must be demonstrated to the Company's satisfaction prior to the Customer's availing of this rate option.

Customers that reduce their demand in aggregate will be treated as a single Customer under this rate option. The aggregated Customer must provide a single point of contact for a request to Curtail.

Credit for Curtailing:

If the Customer Curtails as requested for the duration of a Winter, the Company shall credit to the Customer's account the Curtailment Credit during May billing immediately following that Winter. The Curtailment Credit shall be determined by one of the following options:

Option 1:
The Customer will contract to reduce demand by a specific amount during Curtailment periods (the "Contracted Demand Reduction"). The Curtailment Credit for Option 1 is determined as follows:

Curtailment Credit = Contracted Demand Reduction x $29 per kVA

Option 2:
The Customer will contract to reduce demand to a Firm Demand level which the Customer's maximum demand must not exceed during a Curtailment period. The Curtailment Credit for Option 2 is determined as follows:

Maximum Demand Curtailed = (Maximum Winter Demand - Firm Demand)

$$\text{Peak Period Load Factor} = \frac{\text{kWh usage during Peak Period}}{\text{(Maximum Demand during Peak Period x 1573 hours)}}$$

Curtailment Credit = ((Maximum Demand Curtailed x 50%) + (Maximum Demand Curtailed x 50% x Peak Period Load Factor)) x $29 per kVA

Limitations on Requests to Curtail:

Curtailment periods will:
1. Not exceed 6 hours duration for any one occurrence.
2. Not be requested to start within 2 hours of the expiration of a prior Curtailment period.
3. Not exceed 100 hours duration in total during a winter period.

The Company shall request the Customer to Curtail at least 1 hour prior to the commencement of the Curtailment period.

NEWFOUNDLAND POWER INC.
CURTAILABLE SERVICE OPTION
(for Rates #2.3 and #2.4 only)

Failure to Curtail:

Failure to Curtail under Option 1 occurs when a Customer does not reduce its demand by the Contracted Demand Reduction for the duration of a Curtailment period. Failure to Curtail under Option 2 occurs when a Customer does not reduce its demand to the Firm Demand level or below for the duration of a Curtailment period.

The Curtailment Credit will be reduced for failure to Curtail in a winter period as follows:

1. For the first 5 curtailment requests the Curtailment Credit will be reduced 25% for each failure to Curtail.

2. After the 5th curtailment 50% of the remaining Curtailment Credit, if any, will become vested ("Vested Curtailment Credit").

3. For all remaining curtailment requests the Curtailment Credit will be reduced by 12.5% for each additional failure to Curtail.

If a Customer fails to Curtail four times during a winter period, then:

1. The Customer shall only be entitled to the Vested Curtailable Credit, if any.

2. The Customer will no longer be entitled to service under the Curtailable Service Option.

Notwithstanding the previous paragraph, no Curtailment Credit will be provided if the number of failures to Curtail equals the number of Curtailment requests.

Termination/Modification:

The Company requires six months written notice of the Customer's intention to either discontinue the Curtailable Service Option or to modify the Contracted Demand Reduction or Firm Demand level.

General:

Services billed on this Service Option will have approved load monitoring equipment installed. For a customer that Curtails by using its own generation in parallel with the Company's electrical system, all Company interconnection guidelines will apply, and the Company has the option of monitoring the output of the Customer's generation. All costs associated with equipment required to monitor the Customer's generation will be charged to the Customer's account.

NEWFOUNDLAND POWER INC.
NET METERING SERVICE OPTION
(for Rates #1.1, #1.1S, #2.1,#2.3, and #2.4 only)

Availability:

For Customers who use generation on their Serviced Premises to offset part or all of the electrical energy requirements of the Serviced Premises. Energy generated in excess of the requirements of the Serviced Premises is permitted to be credited against the Customer's energy purchases from the Company in accordance with this rate option.

Net Metering Service is available for any Serviced Premises that is supplied from the Company's distribution system, is billed under one of the Company's metered service rates, and which has generation electrically connected to it that meets the requirements of these provisions. Net Metering Service is not available for unmetered service accounts.

In order to avail of the Net Metering Service Option, Customers must submit a completed Net Metering Service Application to the Company demonstrating the Customer's eligibility for Net Metering Service.

Availability of the Net Metering Service Option will be closed once the provincial aggregate generating capacity for Net Metering Service of 5.0 MW has been met.

Customers that avail of the Net Metering Service Option must maintain compliance with all requirements of this Option. The Company shall have the right to verify compliance through inspection or testing.

Metering:

Net Metering Service will ordinarily be metered using a Company-supplied single meter capable of registering the flow of electrical energy in two directions. The meter will separately capture both the energy supplied to the Customer by the Company and the energy supplied to the Company by the Customer.

At the Company's option, the output of the Customer's generation may be metered separately. In that case, the Customer shall provide the Company with the access necessary to install and maintain the required metering equipment.

The Customer shall pay all costs to upgrade the metering equipment for Net Metering Service if the existing electrical meter at the Serviced Premises is not capable of safely and reliably measuring both the energy supplied to the Customer by the Company and the energy supplied to the Company by the Customer.

NEWFOUNDLAND POWER INC.
NET METERING SERVICE OPTION
(for Rates #1.1, #1.1S, #2.1,#2.3, and #2.4 only)

Billing:

Each account availing of Net Metering Service will be billed on the rate normally applicable to the Customer's class of Service.

The Customer's net monthly bill will be determined by deducting the Customer Generation Credit from the total of all charges for Service. The Customer Generation Credit equals the Generation Energy Credit, in kilowatt-hours ("kWh") multiplied by the rate applicable to the Customer's class of Service during the billing month.

The "Generation Energy Credit" is the sum of the kWh energy supplied by the Customer to the Company during the billing month plus Banked Energy Credits. The Generation Energy Credit for a billing month shall not exceed the energy supplied by the Company to the Customer during that month.

"Banked Energy Credits" are the amount of kWh energy supplied by the Customer to the Company that exceeds the kWh energy supplied by the Company to the Customer. Banked Energy Credits in excess of those used to calculate the Generation Energy Credit for a billing month will be carried forward to the following month.

The balance of the Customer's Banked Energy Credits carried forward will be settled annually by means of a credit on the Customer's bill for the Annual Review Billing Month. The Annual Review Billing Month will be determined by the Customer, in consultation with the Company, during the process of implementing Net Metering Service. Settlement of Banked Energy Credits will be computed based upon the then-current 2nd block energy charge in Newfoundland and Labrador Hydro's Utility Rate applicable to service provided to the Company.

Whenever a Customer's participation in the Net Metering Service Option is discontinued, any unused Banked Energy Credits will be settled with a credit on the Customer's next bill.

All customers must pay Harmonized Sales Tax (HST) on the energy supplied by the Company to the Customer during the billing month. If a Customer availing of Net Metering Service is required by law to collect HST on the energy they supply to the Company, the Company will pay HST to the Customer based on the amount of the Customer Generation Credit. It is the Customer's responsibility to notify the Company in writing if they are required to collect HST on the energy they supply to the Company.

NEWFOUNDLAND POWER INC.
NET METERING SERVICE OPTION
(for Rates #1.1, #1.1S, #2.1,#2.3, and #2.4 only)

Special Conditions:

Special conditions in this clause do not supersede, modify or nullify the conditions accompanying the metered rate schedules applicable to the Customer's class of Service.

To avail of Net Metering Service, a single Customer must own and maintain responsibility for the Serviced Premises, the generation and the electrical facilities connecting it to the Company's distribution system.

To qualify for Net Metering Service, the Customer's generation must meet the following requirements:

i) be designed not to exceed the annual energy requirements of the buildings and facilities metered together on the Serviced Premises;
ii) have a manufacturer's nameplate capacity rating totaling not more than 100 kW, except where a lower rating is stipulated by the Company for technical reasons;
iii) be electrically connected through Customer-owned electrical facilities to the Serviced Premises to which Net Metering Service is being provided;
iv) produce electrical energy from a renewable energy source, including wind, solar, photovoltaic, geothermal, tidal, wave, biomass energy or other renewable energy sources that may be approved by the Company on a case-by-case basis; and
v) meet all applicable safety and performance standards established by the Canadian Electrical Code, the Public Safety Act and the Company's Interconnection Requirements.

All Customer-owned wiring, equipment and devices associated with generation utilized for Net Metering Service shall conform to the Company's interconnection requirements.

The Customer will retain the rights to any renewable energy credits or greenhouse gas-related credits arising from the use of renewable energy sources to generate electricity in accordance with this Option.

A Customer availing of Net Metering Service is responsible for all costs associated with their own facilities. The Customer shall also be required to pay all costs incurred by the Company to modify the utility supply for the provision of Net Metering Service, and for necessary engineering or technical studies required in connection with the provision of Net Metering Service to the Customer.

The approval of an application for Net Metering Service will be subject to the applicant entering into a Net Metering Interconnection Agreement with the Company.

If an applicant approved for Net Metering Service does not proceed with operation of its generation in accordance with its approval within two years from the date of the Company's approval of the application, the approval will be rescinded.

NEWFOUNDLAND POWER INC.
NET METERING SERVICE OPTION
(for Rates #1.1, #1.1S, #2.1,#2.3, and #2.4 only)

Approval of Net Metering Service may be revoked if a Customer is found to be in violation of provisions of the Company's Rules and Regulations.

If participation in the Net Metering Service Option is discontinued, the Customer must re-apply to the Company to avail of the Net Metering Service Option.

NEWFOUNDLAND POWER INC.

RULES AND REGULATIONS

1. INTERPRETATION:

(a) In these Rates, Rules and Regulations the following definitions shall apply:

(i) "Act" means The Public Utilities Act RSN 1970 c. 322 as amended from time to time.
(ii) "Applicant" means any person who applies for Service.
(iii) "Board" means the Board of Commissioners of Public Utilities of Newfoundland and Labrador.
(iv) "Company" means Newfoundland Power Inc.
(v) "Customer" means any person who accepts or agrees to accept Service.
(vi) "Disconnected" or "Disconnect" in reference to a Service means the physical interruption of the supply of electricity thereto.
(vii) "Discontinued" or "Discontinue" in reference to a Service means to terminate the Customer's on-going responsibility with respect to the Service.
(viii) "Domestic Unit" means a house, apartment or other similar residential unit which is normally occupied by one family, or by a family and no more than four other persons who are not members of that family, or which is normally occupied by no more than six unrelated persons.
(ix) "Service" means any service(s) provided by the Company pursuant to these Regulations.
(x) "Serviced Premises" means the premises at which Service is delivered to the Customer.

(b) Unless the context requires otherwise these Rates, Rules and Regulations shall be interpreted such that

(i) words imparting male persons include female persons and corporations.

(ii) words imparting the singular include the plural and vice versa.

2. CLASSES OF SERVICE:

(a) The Company shall provide the following classes of Service:

(i) Domestic Service
(ii) General Service, 0-100 kW (110 kVA)
(iii) General Service, 110 kVA (100 kW) - 1000 kVA
(iv) General Service, 1000 kVA and Over
(v) Street and Area Lighting Service

(b) The terms and conditions relating to each class of Service shall be those approved by the Board from time to time.

(c) Service, other than Street and Area Lighting Service, shall be metered except where the energy consumption is relatively low and constant and, in the opinion of the Company, can be readily determined without metering.

NEWFOUNDLAND POWER INC.

RULES AND REGULATIONS

(d) The Customer shall use the Service on the Serviced Premises only. The Customer shall not resell the Service in whole or in part, except that the Customer may include the cost of Service in charges for the lease of space, or as part of the cost of other services provided by the Customer.

3. APPLICATION FOR SERVICE:

(a) An Applicant, when required by the Company, shall complete a written Electrical Service Contract.

(b) An application for Service, when accepted by the Company, constitutes a binding contract between the Applicant and the Company which cannot be assigned.

(c) The person who signs an application for Service shall be personally liable for Service provided pursuant thereto, unless that person has authority to act for another person denoted as the Applicant on the application for Service.

(d) The Company may in its discretion refuse to provide Service to an Applicant where:

(i) the Applicant fails or refuses to complete an application for Service.

(ii) the Applicant provides false or misleading information on the application for Service.

(iii) the Applicant or the owner or an occupant of the Serviced Premises has a bill for any Service which is not paid in full 30 days or more after issuance.

(iv) the Applicant fails to provide the security or guarantee required under Regulation 4.

(v) the Applicant is not the owner or an occupant of the Serviced Premises.

(vi) the Service requested is already supplied to the Serviced Premises for another Customer who does not consent to having his Service Discontinued.

(vii) the Applicant does not pay a charge described in Regulation 9 (b), (c), or (d).

(viii) the Applicant otherwise fails to comply with these Regulations.

(e) A Customer who has not completed an application for Service shall do so within 5 days of a request having been made by the Company in writing.

NEWFOUNDLAND POWER INC.

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4. SECURITY FOR PAYMENT:

(a) An Applicant or a Customer shall give such reasonable security for the payment of charges as may be required by the Company pursuant to its Customer Deposit Policy as approved by the Board, from time to time.

(b) The Company may in its discretion require special guarantees from an Applicant or Customer whose location or load characteristics would require abnormal investment in facilities or who requires Service of a special nature.

5. SERVICE STANDARDS - METERED SERVICES:

(a) Service shall normally be provided at one of the following nominal standard secondary voltages depending upon the requirements of the load to be served and the availability of a three-phase supply:

Single-phase, 3 wire, 120/240 volts
Three-phase, 4 wire, 120/208 volts wye
Three-phase, 4 wire, 347/600 volts wye

Service at any other supply voltage may be provided in special cases at the discretion of the Company.

(b) Service to customers who are provided Domestic Service shall be supplied at single phase 120/240 volts or as part of a multiunit building, at single phase 120/208 volts. The Company may, if requested by the customer, provide three phase service if a contribution in aid of construction is paid to the Company in accordance with Regulation 9(c).

(c) The Company shall not be required to provide services at 50 hertz except to those Serviced Premises receiving 50 hertz power continuously since May 13, 1977.

(d) The Company shall determine the point at which power and energy is delivered from the Company's facilities to the Customer's electrical system.

(e) Service entrances shall be in a location satisfactory to the Company and, except as otherwise approved by the Company, shall be wired for outdoor meters.

(f) Where the Company has reason to believe that Service to a Customer has or will have load characteristics which may cause undue interference with Service to another Customer, the Customer shall upon written notice by the Company provide and install, at his expense and within a reasonable period of time, the equipment necessary to eliminate or prevent such interference.

NEWFOUNDLAND POWER INC.

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(g) (i) Any Customer having a connected load or a normal operating demand of more than 25 kilowatts, in areas served by underground wiring or where space limitations or aesthetic reasons make it impractical to use a pole mounted transformer bank or pad transformer, shall, on request of the Company, provide at its expense a suitable vault or enclosure on the Serviced Premises for exclusive use by the Company for its equipment necessary to supply and maintain service to the Customer.

(ii) Where either the service requirements of a Customer or changes to a Customer's electrical system necessitate the installation of additional equipment to the Company's system which cannot be accommodated in the Company's existing vaults or structures, the Customer shall, on request of the Company, provide at the Customer's expense such additional space in its vault or enclosure as the Company shall require to accommodate the additional equipment.

(h) The Customer shall not use a Service for across the line starting of motors rated over 10 horsepower, except where specifically approved by the Company.

(i) For Services having rates based on kilowatt demand, the average power factor shall not be less than 90%. The Company, in its discretion, may make continuous tests of power factor or may test the Customer's power factor from time to time. If the Customer's power factor is lower than 90%, the Customer shall upon written notice by the Company provide, at his expense, power factor corrective equipment to ensure that a power factor of not less than 90% is maintained.

(j) The Company shall provide transformation for Service up to 500 kVA where the required service voltage is one of the Company's standard service voltages and installation is in accordance with the Company's standards. In other circumstances, the Company, on such conditions as it deems acceptable, may provide the transformation.

(k) All Customer wiring and installations shall be in compliance with all statutory and regulatory requirements including the Canadian Electrical Code, Part 1, and, where applicable, in accordance with the Company's specifications. However, the provision of Service shall not in any way be construed as acceptance by the Company of the Customer's electrical system.

(l) The Customer shall provide such protective devices as may be necessary to protect his property and equipment from any disturbance beyond the reasonable control of the Company.

NEWFOUNDLAND POWER INC.

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6. SERVICE STANDARDS - STREET AND AREA LIGHTING SERVICE:

(a) For Street and Area Lighting Service the Company shall use its best efforts to provide illumination during the hours of darkness for a total of approximately 4200 hours per year. The Company shall, subject to Regulation 9 (i) make all repairs necessary to maintain service.

(b) The Company shall supply the energy required and shall provide and maintain the illuminating fixtures and lamps together with necessary overhead or underground conductors, control equipment and other devices.

(c) The Company shall not be required to provide Street And Area Lighting Service where, in the opinion of the Company, the normal Service is unsuitable for the task or where the nature of the activities carried out in the area would likely result in damage to the poles, wiring or fixtures.

(d) The Company shall provide a range of fixture sizes utilizing an efficient lighting source in accordance with current standards in the industry and shall consult with the Customer regarding the most appropriate use of such fixtures for any specific installation.

(e) The location of fixtures for Street and Area Lighting Service shall be determined by the Company in consultation with the Customer. After poles and fixtures have been installed they shall not be relocated except at the expense of the Customer.

(f) The Company does not guarantee that fixtures used for Street And Area Lighting Service will illuminate any specific area.

(g) The Company shall not be required to provide additional Street And Area Lighting Service to a Customer where on at least two occasions in the preceding twelve months, his bill for such Service has been in arrears for more than 30 days.

7. METERING:

(a) Service to each building shall be metered separately except as provided in Regulation 7(b).

(b) Service to buildings and facilities on the same Serviced Premises which are occupied by the same Customer may, subject to Regulation 7(c), be metered together provided the Customer supplies and maintains all distribution facilities beyond the point of supply.

(c) Except as provided in Regulation 7(d), Service to each new Domestic Unit shall be metered separately.

(d) Where an existing Domestic Unit is subdivided into two or more new Domestic Units, Service to the new Domestic Units may, in the discretion of the Company, be metered together.

NEWFOUNDLAND POWER INC.

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(e) Where four or more Domestic Units are metered together, the Basic Customer Charge shall be multiplied by the number of Domestic Units.

(f) Where the Service to a Domestic Unit has a 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.

(g) The Company shall not be required to provide more than one meter per Service, however submetering by the Customer for any purpose not inconsistent with these Regulations, is permitted.

(h) Subject to Regulations 7(c) and 7(g) Service to different units of a building may, at the request of the Customer, be combined on one meter or be metered separately.

(i) Maximum demand for billing purposes shall be determined by demand meter or, at the option of the Company, may be based on:

(i) 80% of the connected load, where the demand does not exceed 100 kW, or

(ii) the smallest size transformer(s) required to serve the load if it is intermittent in nature such as X-Ray, welding machines or motors that operate for periods of less than thirty minutes, or

(iii) the kilowatt-hour consumption divided by an appropriate number of hours use where demand is less than 10 kW.

(j) When charges are based on maximum demand the metering shall normally be in kVA if the applicable rate is in kVA and in kW if the applicable rate is in kW.

If the demand is recorded on a kVA meter but the applicable rate is based on a kW demand, the recorded demand may be decreased by ten percent (10%) and the result shall be treated as the kW demand for billing purposes.

If the demand is recorded on a kW meter but the applicable rate is based on a kVA demand, the recorded demand may be increased by ten percent (10%) and the result shall be treated as the kVA demand for billing purposes.

(k) The Customer shall ensure that meters and related equipment are visible and readily accessible to the Company's personnel and are suitably protected. Unless otherwise approved by the Company, meters shall be located outdoors and shall not subsequently be enclosed.

NEWFOUNDLAND POWER INC.

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(l) If a meter is located indoors and Company employees are unable to obtain access to read the meter at the normal reading time for three consecutive months, the Customer shall upon written notice given by the Company, provide for the installation of an outdoor meter at his expense.

(m) In the event that a dispute arises regarding the accuracy of a meter, and the Company is unable to resolve the matter with the Customer then either the Customer or the Company shall have the right to request an accuracy test in accordance with the requirements of the Electricity Inspection Act of Canada. Should the test indicate that the meter accuracy is not within the allowable limits, the Customer's bill shall be adjusted in accordance with the provisions of the said Act and all costs involved in the removal and testing of the meter shall be borne by the Company. Should the test confirm the accuracy of the meter, the costs involved shall be borne by the party requesting the test. The Company may require a Customer to deposit with the Company in advance of testing, an amount sufficient to cover the costs involved.

(n) Metering shall normally be at secondary distribution voltage level but may at the option of the Company be at the primary distribution level. When metering is at the primary distribution voltage (4 - 25 kV) the monthly demand and energy consumption shall be reduced by 1.5%.

8. METER READING:

(a) Where reasonably possible the Company shall read meters monthly provided that the Company may, at its discretion, read meters at some other interval and estimate the reading for the intervening month(s). Areas which consist primarily of cottages will have their meters read four times per year and the Company will estimate the readings for all other months.

(b) If the Company is unable to obtain a meter reading due to circumstances beyond its reasonable control, the Company may estimate the reading.

(c) If due to any cause a meter has not correctly recorded energy consumption or demand, then the probable consumption or demand shall be estimated in accordance with the best data available and used to determine the relevant charge.

9. CHARGES:

(a) Every Customer shall pay the Company the charges approved by the Board from time to time for the Service(s) provided to the Customer or provided to the Serviced Premises at the Customer's request.

NEWFOUNDLAND POWER INC.

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(b) Where a Customer requires Service for a period of less than three (3) years, the Customer shall pay the Company a "Temporary Connection Fee". The Temporary Connection Fee is calculated as the estimated labour cost of installing and removing lines and equipment necessary for the Service plus the estimated cost of non-salvageable material. The payment may be required in advance or, subject to credit approval, billed to the Customer.

(c) Where special facilities are required or requested by the Customer or any facility is relocated at the request of the Customer, the Customer shall pay the Company the estimated additional cost of providing the special facilities and the estimated cost of the relocation less any betterment. The payment may be required in advance or, subject to credit approval, billed to the Customer.

(d) The Customer shall pay the Company in advance or on such other terms approved by the Board from time to time any contribution in aid of construction as may be determined by the methods prescribed by the Board.

(e) The Customer shall pay the Company the amount set forth in the rate for all poles required for Street and Area Lighting Service which are in addition to those installed by the Company for the distribution of electricity. This charge shall not apply to Company poles and communications poles used jointly for Street and Area Lighting Service and communications attachments.

(f) Where a Service is Disconnected pursuant to Regulation 12(a), b(ii), (c) or (d) and the Customer subsequently requests that the service be reconnected, the Customer shall pay a reconnection fee.

Where a Service is Disconnected pursuant to Regulation 12(g) and an Applicant subsequently requests that the service be reconnected, the Applicant shall pay a reconnection fee. Applicants that pay the reconnection fee will not be required to pay the application fee.

The reconnection fee shall be $20.00 where the reconnection is done during normal office hours or $40.00 if it is done at other times.

(g) Where a Service, other than a Street and Area Lighting Service, is Discontinued pursuant to Regulation 11(a), or Disconnected pursuant to Regulations 12(a), b(ii), (c) or (d) and the Customer subsequently requests that the Service be restored within 12 months, the Customer shall pay, in advance, the minimum monthly charges that would have been incurred over the period if the Service had not been Discontinued or Disconnected.

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(h) (i) Where a Street and Area Lighting Service is Discontinued pursuant to Regulation 11 (a), (b) or (c), or 9 (i), or when a Customer requests removal of existing fixtures, poles, and/or underground wiring, the Customer shall pay at the time of removal an amount equal to the unrecovered capital cost, plus the cost of removal less any salvage value of only the poles and/or underground wiring to be Discontinued or removed.

(ii) If a Customer requests the subsequent replacement of the fixture, either immediately or at any time within 12 months by another, whether or not of the same type or size, the Customer shall pay, in advance, an amount equal to the unrecovered capital cost of the fixture removed, plus the cost of removal, less any non-luminaire salvage, as well as the monthly charges that would have been incurred over the period if the Service had not been Discontinued.

(iii) Where a Street and Area Lighting Service is Discontinued, any pole dedicated solely to the Street and Area Lighting Service may, at the Customer's request, remain in place for up to 24 months from the date of removal of the fixture, during which time the Customer shall continue to pay the prescribed monthly charge for the pole and underground wiring.

(i) Where Street and Area Lighting fixtures or lamps are wantonly, wilfully, or negligently damaged or destroyed (other than through the negligence of the Company), the Company, at its option and after notifying the Customer by letter, shall remove the fixtures and the monthly charges for these fixtures will cease thirty days after the date of the letter. However, if the Customer contacts the Company within thirty days of the date on the letter and agrees to pay the repair costs in advance and all future repair costs, the Company will replace the fixture and rental charges will recommence. If any future repair costs are not paid within three months of the date invoiced, the Company, after further notifying the Customer by letter, may remove the fixtures. In all such cases the fixtures shall not be replaced unless the Customer pays to the Company in advance all amounts owing prior to removal plus the cost of removing the old fixtures and installing the new fixtures.

(j) Where a Service other than Street and Area Lighting Service is not provided to the Customer for the full monthly billing period or where Street and Area Lighting Service is not provided for more than seven (7) days during the monthly billing period, the relevant charge to the Customer for the Service for that period may be prorated except where the failure to provide the Service is due to the Customer or to circumstances beyond the reasonable control of the Company.

(k) Where a Customer's Service is at primary distribution or transmission voltage and the Customer provides his own transformation and all other facilities beyond the designated point of supply the monthly demand charge shall, subject to the minimum monthly charge, be reduced as follows:

(i) for supply at 4 kV to 25 kV	$0.40 per kVA
(ii) for supply at 33 kV to 138 kV	$0.90 per kVA

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(l) Where a Customer's monthly demand has been permanently reduced because of the installation of peak load controls, power factor correction, or by rendering sufficient equipment inoperable, by any means satisfactory to the Company, the monthly demands recorded prior to the effective date of such reduction may be adjusted when determining the Customer's demand for billing purposes thereafter. Should the Customer's demand increase above the adjusted demands in the following 12 months, the Customer will be billed for the charges that would have been incurred over the period if the demand had not been adjusted.

(m) Charges may be based on estimated readings or costs where such estimates are authorized by these Regulations.

(n) An application fee of $8.00 will be charged for all requests for Customer name changes and connection of new Serviced Premises. Landlords will be exempted from the application fee for name changes at Service Premises for which a landlord agreement pursuant to Regulation 11(f) is in effect.

10. BILLING:

(a) The Company shall bill the Customer monthly for charges for Service. However, when a Service is disconnected or a bill is revised the Company may issue an additional bill.

(b) The charges for Street and Area Lighting Service may be included as a separate item on a bill for any other Service.

(c) Bills are due and payable when issued. Payment shall be made at such place(s) as the Company may designate from time to time. Where a bill is not paid in full by the date that a subsequent bill is issued and the amount outstanding is $50.00 or more, the Company may charge interest at a rate equal to the prime rate charged by chartered banks on the last day of the previous month plus five percent.

(d) Where a Customer’s cheque or automated payment is not honoured by their financial institution, a charge of $16.00 may be applied to the Customer’s bill.

(e) Where a Customer is billed on the basis of an estimated charge an adjustment shall be made in a subsequent bill should such estimate prove to be inaccurate.

(f) Where between normal meter reading dates, one Customer assumes from another Customer the responsibility for a metered Service, or a Service is Discontinued, the Company may base the billing on an estimate of the reading as of the date of change.

(g) Where a Customer has been underbilled due to an error on the part of the Company or due to an act or omission by a third party, the Customer may, at the discretion of the Company, be relieved of the responsibility for all or any part of the amount of the underbilling.

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11. DISCONTINUANCE OF SERVICE:

(a) A Service may be Discontinued by the Customer at any time upon prior notice to the Company provided that the Company may require 10 days prior notice in writing.

(b) A Service may be Discontinued by the Company upon 10 days prior notice in writing to the Customer if the Customer:

(i) provided false or misleading information on the application for the Service.

(ii) fails to provide security or guarantee for the Service required under Regulation 4.

(c) A Service may be Discontinued by the Company without notice if the Service was Disconnected pursuant to Regulation 12, and has remained Disconnected for over 30 consecutive days.

(d) When the Company accepts an application for Service, any prior contract for the same Service shall be Discontinued except where an agreement for that service is signed by a landlord under Regulation 11(f).

(e) Where a Service has been Discontinued, the Service may, at the option of the Company and subject to Regulation 12(a), remain connected.

(f) A landlord may sign an agreement with the Company to accept charges for Service provided to a rental premise for all periods when the Company does not have a contract for Service with a tenant for that premise.

12. DISCONNECTION OF SERVICE:

(a) The Company shall Disconnect a Service within 10 days of receipt of a written request from the Customer.

(b) The Company may Disconnect a Service without notice to the Customer:
(i) where the Service has been Discontinued,
(ii) on account of or to prevent fraud or abuse,
(iii) where in the opinion of the Company the Customer's electrical system is defective and represents a danger to life or property,
(iv) where the Customer's electrical system has been modified without compliance with the Electrical Regulations,
(v) where the Customer has a building or structure under the Company's wires which is within the minimum clearances recommended by the Canadian Standards Association, or
(vi) when ordered to do so by any authority having the legal right to issue such order.

NEWFOUNDLAND POWER INC.

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(c) The Company may, in accordance with its Collection Policies filed with the Board, Disconnect a Service upon prior notice to the Customer if the Customer has a bill for any Service which is not paid in full 30 days or more after issuance.

(d) The Company may Disconnect a Service upon 10 days prior notice to the Customer if the Customer is in violation of any provision of these Regulations.

(e) The Company may refuse to reconnect a Service if the Customer is in violation of any provisions of these Regulations or if the Customer has a bill for any Service which is unpaid.

(f) The Company may Disconnect a Service to make repairs or alterations. Where reasonable and practical the Company shall give prior notice to the Customer.

(g) The Company may Disconnect the Service to a rental premises where the landlord has an agreement with the Company authorizing the Company to Disconnect the Service for periods when the Company does not have a contract for Service with a tenant of that premises.

13. PROPERTY RIGHTS:

(a) The Customer shall provide the Company with space and cleared rights-of-way on private property for the line(s) and facilities required to serve the Customer.

(b) The Company shall have the right to install, remove or replace such of its property as it deems necessary.

(c) The Customer shall provide the Company with access to the Serviced Premises at all reasonable hours for purposes of reading a meter or installing, replacing, removing or testing its equipment, and measuring or checking the connected load.

(d) All equipment and facilities provided by the Company shall remain the property of the Company unless otherwise agreed in writing.

(e) The Customer shall not unreasonably interfere with the Company's access to its property.

(f) The Customer shall not attach wire, cables, clotheslines or any other fixtures to the Company's poles or other property except by prior written permission of the Company.

(g) The Customer shall allow the Company to trim all trees in close proximity to service lines in order to maintain such lines in a safe manner.

(h) The Customer shall not erect any buildings or obstructions on any of the Company's easement lands or alter the grade of such easements by more than 20 centimetres, without the prior approval of the Company.

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RULES AND REGULATIONS

14. COMPANY LIABILITY:

The Company shall not be liable for any failure to supply Service for any cause beyond its reasonable control, nor shall it be liable for any loss, damage or injury caused by the use of Services or resulting from any cause beyond the reasonable control of the Company.

15. GENERAL:

(a) No employee, representative or agent of the Company has the authority to make any promise, agreement or representation, whether verbal or otherwise, which is inconsistent with these Regulations and no such promise, agreement or representation shall be binding on the Company.

(b) Any notice under these Regulations will be considered to have been given to the Customer on the date it is received by the Customer or three days following the date it was delivered or mailed by the Company to the Customer's last known address, whichever is sooner.

NEWFOUNDLAND POWER INC.

RATE STABILIZATION CLAUSE

The Company shall include a rate stabilization adjustment in its rates. This adjustment shall reflect the accumulated balance in the Company's Rate Stabilization Account ("RSA") and any change in the rates charged to the Company by Newfoundland and Labrador Hydro ("Hydro") as a result of the operation of its Rate Stabilization Plan ("RSP").

I. RATE STABILIZATION ADJUSTMENT ("A")

The Rate Stabilization Adjustment ("A") shall be calculated as the total of the Recovery Adjustment Factor and the Fuel Rider Adjustment.

The Recovery Adjustment Factor shall be recalculated annually, effective the first day of July in each year, to amortize over the following twelve (12) month period the annual plan recovery amount designated to be billed by Hydro to the Company, and the balance in the Company's RSA.

The Recovery Adjustment Factor expressed in cents per kilowatt-hour and calculated to the nearest 0.001 cent shall be calculated as follows:

$$\frac{\mathbf{B1 + B2 + C}}{\mathbf{D}}$$

Where:

B1 = the annual plan recovery amount designated to be billed by Hydro during the next twelve (12) months commencing July 1 as a result of the operation of Hydro's RSP.

B2 = the annual plan recovery amount designated to be billed by Hydro during the next twelve (12) months commencing July 1 as a result of the operation of Hydro's CDM Cost Recovery Adjustment.

C = the balance in the Company's RSA as of March 31st of the current year.

D = the total kilowatt-hours sold by the Company for the 12 months ending March 31st of the current year.

The Fuel Rider Adjustment shall be recalculated annually, effective the first day of July in each year, to reflect changes in the RSP fuel rider applicable to Newfoundland Power. The Fuel Rider Adjustment expressed in cents per kilowatt-hour and calculated to the nearest 0.001 cent shall be calculated as follows:

$$\frac{\mathbf{E}}{\mathbf{D}} \times \mathbf{F}$$

NEWFOUNDLAND POWER INC.

RATE STABILIZATION CLAUSE

I. RATE STABILIZATION ADJUSTMENT ("A") (Cont'd)

Where:

D = corresponds to the D above.

E = the total kilowatt-hours of energy (including secondary energy) sold to the Company by Hydro during the 12 months ending March 31 of the current year.

F = the fuel rider designated to be charged to Newfoundland Power through Hydro's RSP.

The Rate Stabilization Adjustment ("A") shall be recalculated and be applied as of the effective date of a new wholesale mill rate by Hydro, by resetting the Fuel Rider Adjustment included in the Rate Stabilization Adjustment to zero.

II. RATE STABILIZATION ACCOUNT ("RSA")

The Company shall maintain a RSA which shall be increased or reduced by the following amounts expressed in dollars:

1. At the end of each month the RSA shall be:

   (i) increased (reduced) by the amount actually charged (credited) to the Company by Hydro during the month as the result of the operation of its Rate Stabilization Plan.

   (ii) increased (reduced) by the excess cost of fuel used by the Company during the month calculated as follows:

$$\mathbf{(G/H - P) \quad x \quad H}$$

Where:

G = the cost in dollars of fuel and additives used during the month in the Company's thermal plants to generate electricity other than that generated at the request of Hydro.

H = the net kilowatt-hours generated in the month in the Company's thermal plants other than electricity generated at the request of Hydro.

NEWFOUNDLAND POWER INC.

RATE STABILIZATION CLAUSE

II. RATE STABILIZATION ACCOUNT ("RSA") (Cont'd)

P = the 2nd block base rate in dollars per kilowatt-hour paid during the month by the Company to Hydro for firm energy.

(iii) reduced by the price differential of firmed-up secondary energy calculated as follows:

$$(P - J) \times K$$

Where:

J = the price in dollars per kilowatt-hour paid by the Company to Hydro during the month for secondary energy supplied by Deer Lake Power and delivered as firm energy to the Company.

K = the kilowatt-hours of such secondary energy supplied to the Company during the month.

P = corresponds to P above.

(iv) reduced (increased) by the amount billed by the Company during the month as the result of the operation of the Rate Stabilization Clause calculated as follows:

$$\frac{L \times A}{100}$$

Where:

L = the total kilowatt-hours sold by the Company during the month.

A = the Rate Stabilization Adjustment in effect during the month expressed in cents per kilowatt-hour.

(v) increased (reduced) by an interest charge (credit) on the balance in the RSA at the beginning of the month, at a monthly rate equivalent to the mid-point of the Company's allowed rate of return on rate base.

2. On the 31st of December in each year, the RSA shall be increased (reduced) by the amount that the Company billed customers under the Municipal Tax Clause for the calendar year is less (or greater) than the amount of municipal taxes paid for that year.

NEWFOUNDLAND POWER INC.

RATE STABILIZATION CLAUSE

II. RATE STABILIZATION ACCOUNT ("RSA") (Cont'd)

3. The annual kilowatt-hours used in calculating the Rate Stabilization Adjustment to the monthly street lighting rates are as follows:

	Fixture Size (watts)			
	100	150	250	400
High Pressure Sodium	454	714	1,260	1,953

	Fixture Type			
	LED 100	LED 150	LED 250	LED 400
Light Emitting Diode	218	290	475	664

4. On December 31, 2017, the RSA shall be reduced (increased) by the amount that the increase in the Company's revenue for the year resulting from the change in base rates attributable to the flow through of Hydro's wholesale rate change, effective July 1, 2017, is greater (or less) than the amount of the increase in the Company's purchased power expense for the year resulting from the change in the base rate charged by Hydro effective July 1, 2017.

   The methodology to calculate the RSA adjustment at December 31, 2017 is as follows:

Calculation of increase in Revenue:	
2017 Revenue with Flow-through (Q)	$ -
2017 Revenue without Flow-through (R)	$ -
Increase in Revenue (S = Q – R)	$ -
Calculation of increase in Purchased Power Expense:	
2017 Purchased Power Expense with Hydro Increase (T)	$ -
2017 Purchased Power Expense without Hydro Increase (U)	$ -
Increase in Purchased Power Expense (V = T – U)	$ -
Adjustment to Rate Stabilization Account (W = S – V)	$ -

Where:

Q = Normalized revenue from base rates effective July 1, 2017.

R = Normalized revenue from base rates determined based on rates effective July 1, 2016.

T = Normalized purchased power expense from Hydro's wholesale rate effective July 1, 2017 (not including RSP rate).

U = Normalized purchased power expense determined based on Hydro's wholesale rate effective July 1, 2015 (not including RSP rate).

NEWFOUNDLAND POWER INC.

RATE STABILIZATION CLAUSE

II. RATE STABILIZATION ACCOUNT ("RSA") (Cont'd)

5. On December 31st of each year from 2008 until further order of the Board, the Rate Stabilization Account (RSA) shall be increased (reduced) by the Energy Supply Cost Variance.

   This Energy Supply Cost Variance identifies the change in purchased power cost that is related to the difference between purchasing energy at the 2nd block energy charge in the wholesale rate and the test year energy supply cost reflected in customer rates.

   The Energy Supply Cost Variance expressed in dollars shall be calculated as follows:

$$\frac{(A - B) \times (C - D)}{100}$$

   Where:

   A = the wholesale rate 2nd block charge per kWh.

   B = the test year energy supply cost per kWh determined by applying the wholesale energy rate to the test year energy purchases and expressed in ¢ per kWh.

   C = the weather normalized annual purchases in kWh.

   D = the test year annual purchases in kWh.

6. The RSA shall be adjusted by any other amount as ordered by the Board.

7. On March 31st of each year, beginning in 2014, the Rate Stabilization Account shall be increased on a before tax basis, by the CDM Cost Recovery Transfer.

   The CDM Cost Recovery Transfer, expressed in dollars, will be calculated to provide for the recovery of costs charged annually to the Conservation and Demand Management Cost Deferral Account (the "CDM Cost Deferral") over a seven-year period, commencing in the year following the year in which the CDM Cost Deferral is charged to the Conservation and Demand Management Cost Deferral Account.

   The CDM Cost Deferral Account will identify the year in which each CDM Cost Deferral was incurred.

NEWFOUNDLAND POWER INC.

RATE STABILIZATION CLAUSE

II. RATE STABILIZATION ACCOUNT ("RSA") (Cont'd)

The CDM Cost Recovery Transfer for each year will be the sum of individual amounts representing 1/7th of each CDM Cost Deferral, which individual amounts shall be included in the CDM Cost Recovery Transfer for seven years following the year in which the CDM Cost Deferral was recorded.

8. On March 31st of each year, beginning in 2013, the Rate Stabilization Account shall be increased (reduced), on a before tax basis, by the balance in the Weather Normalization Reserve accrued in the previous year.

III. RATE CHANGES

The energy charges in each rate classification shall be adjusted as required to reflect the changes in the Rate Stabilization Adjustment. The new energy charges shall be determined by subtracting the previous Rate Stabilization Adjustment from the previous energy charges and adding the new Rate Stabilization Adjustment. The new energy charges shall apply to all bills based on consumption on and after the effective date of the adjustment.

NEWFOUNDLAND POWER INC.

MUNICIPAL TAX CLAUSE

I. MUNICIPAL TAX ADJUSTMENT ("MTA")

The Company shall include a MTA in its rates to reflect taxes charged to the Company by municipalities.

A MTA factor shall be calculated annually, effective the first day of July in each year, to collect over the following twelve (12) month period, an amount to cover municipal taxes. The MTA factor rounded to the nearest fifth decimal shall be calculated as follows:

$$\frac{X}{Y} + 1.00000$$

Where:

X = the amount of all municipal taxes paid by the Company in the previous calendar year.

Y = the amount of revenue earned by the Company in the previous calendar year less the amount collected by the Company under the Municipal Tax Clause in that year.

The MTA factor shall apply to all charges in all rate descriptions. These charges shall be adjusted annually effective the first day of July in each year to reflect changes in the MTA factor. The new charges rounded to the nearest significant number expressed in the rate descriptions shall be determined by multiplying each charge by the MTA factor. The new charges shall apply to all bills based on consumption on and after the first day of July.

The MTA factor shall be applied after application of the Rate Stabilization Adjustment.

SECTION 1: INTRODUCTION

1.1 APPLICATION BACKGROUND

1.1.1 About Newfoundland Power

Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") business is principally electricity distribution and customer service delivery. The Company serves a mature market.

Newfoundland Power is dependent upon Newfoundland and Labrador Hydro ("Hydro") to supply approximately 93% of the electricity the Company delivers to customers.

Table 1-1 shows the number of customers served by Newfoundland Power and the Company's annual weather-adjusted energy sales for the period 2015 to 2020F.

Table 1-1:
Customers and Sales
2015 to 2020F

	2015	2016	2017	2018F	2019F	2020F
Customers	261,774	264,406	266,450	268,168	269,683	271,222
Sales (GWh)	5,957	5,950	5,922	5,915	5,883	5,887

The number of customers served by Newfoundland Power is expected to increase by approximately 0.7% per year from 2015 to 2020. Annual weather-adjusted energy sales are expected to decrease by approximately 0.2% per year over the same period.

Newfoundland Power is experiencing a period of lower customer growth and reduced sales. This is consistent with the recent decline in the provincial economy. The economic decline is attributable to several factors, including lower commodity prices, reduced shellfish processing, and reduced construction activity related to major projects. These conditions are expected to continue into the forecast period.

Domestic service customers account for the largest percentage of Newfoundland Power's sales. Sales to domestic service customers decreased by approximately 0.3% from 2015 to 2017 and are expected to decline a further 2.0% by 2020.

Sales to general service customers are forecast to increase by 0.5% from 2015 to 2020. This reflects a combination of changes in the status of major projects throughout the period. Among these changes are the completion of the Hebron offshore oil project in 2017, the reactivation of the fluorspar mine in St. Lawrence in late 2017, and the start of the West White Rose Project in 2018.

The Company's long-term growth outlook is uncertain. This uncertainty reflects a weak economic outlook for the province and expected increases in the cost of electricity following interconnection of Nalcor Energy's Muskrat Falls project.

1.1.2 Customer Expectations

Newfoundland Power is responsible for serving approximately 87% of all electricity customers in Newfoundland and Labrador. Quarterly surveys indicate the principal factors affecting customers' satisfaction with the Company's service delivery are reliability and price.

Customers expect the service they receive to be reliable. This requires Newfoundland Power to maintain the condition of its electrical system to minimize customer outages. It also requires the Company to maintain the necessary capabilities to respond to customer outages when they occur.

Customers expect the service they receive to be reasonably priced. Balancing reliability and least-cost service delivery requires efficiency within the Company's operations.

These expectations are broadly reflected in Newfoundland and Labrador's provincial power policy. The policy requires the Company to manage its operations in a manner that results in power being delivered to customers at the lowest possible cost consistent with reliable service.[1] Reliability and cost management are therefore cornerstones of Newfoundland Power's service delivery.

Customers' service expectations are not static. For example, managing customer communications requires responding to customers' evolving use of technology. This includes customers' increasing use of digital channels to communicate with the Company. Responding to evolving expectations can offer opportunities to improve both the Company's service delivery and its operating efficiency.

1.1.3 Newfoundland Power's Performance

The Company's electrical system has performed reliably.

[1] Section 3(b)(iii) of the *Electrical Power Control Act, 1994.*

The average duration of customer outages has been ½ the Canadian average over the last 10 years. The average frequency of customer outages has been consistent with the Canadian average.

The assets comprising Newfoundland Power's electrical system have been in service for an average of 30 years. The Company maintains the reliability of these assets through periodic inspection and maintenance programs and targeted capital investments. These practices have reduced equipment failures and improved the reliability experienced by customers.

Newfoundland Power has demonstrated sound cost management.

The Company served over 50,000 more customers in 2017 than in 1998. It responded to over 2 million additional contacts from customers in 2017 than in 1998. However, customer service costs have declined by approximately 8% over the same period.

Serving more customers at a lower cost has required efficiency within Newfoundland Power's operations. Cost management has included initiatives of various scales. For example, the automation of meter reading has allowed the Company to substantially reduce meter reading costs. Increased customer participation in ebills has reduced postage costs while postal rates continue to rise. Expanding and enhancing digital communication channels has provided customers with increased access to self-service options. Each of these initiatives has helped the Company balance cost management with meeting customers' service expectations.

Newfoundland Power will continue to focus on the delivery of reliable service at the lowest possible cost.

Customers have shown a continued interest in energy conservation. The Company is currently at the midway point of implementing a 5-year energy conservation plan with Hydro. Total costs and energy savings achieved to date are consistent with the *Five-Year Conservation Plan: 2016-2020*. Implementation of the plan will continue through 2020.

Labour costs account for over ½ of the Company's annual operating costs. These are the costs over which Newfoundland Power management can assert the most control. Between 2015 and 2020, the Company expects its annual operating labour costs to increase by approximately 1.7% per year. This is lower than Newfoundland Power's labour rate inflation and indicates sound cost management over the forecast period.

Increased labour costs include planning for the replacement of the Company's 25-year-old Customer Service System. This system has supported the delivery of efficient and responsive customer service for over 2 decades and has exceeded its expected service life. Planning for replacement of the system is necessary to ensure continuity in customer service delivery.

1.1.4 Electricity Sector Developments

Developments in the electricity sector since the Company's last general rate application in 2016 provide essential context for the consideration of this Application.

Newfoundland Power is dependent upon Hydro to supply the majority of electricity required to serve customers. Wholesale power supply costs are a principal driver of the Company's cost of providing service to customers.

Interconnection of Nalcor Energy's Muskrat Falls project will be a transformative event for the Island Interconnected System. For the first time, the island of Newfoundland's largest source of electricity supply will be located off the island, approximately 1,100 kilometres from the location of the province's largest customer load on the Avalon Peninsula.

Since the Company's last general rate application, the total capital cost of the Muskrat Falls project has increased by over ⅓. The total project investment is currently estimated to be $12.7 billion. This investment is nearly 4 times greater than the combined book value of Hydro's and Newfoundland Power's existing assets. In addition, Nalcor Energy's estimated operating costs for the project have tripled since Newfoundland Power's last general rate application. Current estimates indicate the annual operating costs for the project will be $109 million per year. This is nearly double the annual operating costs of Newfoundland Power.

While there have been material increases in the costs of the Muskrat Falls project, the recovery of these costs remains uncertain. Recovery of Muskrat Falls project costs are required to be borne by Newfoundland Power customers through customer rates. Nalcor Energy has estimated the recovery of these costs will require existing provincial electricity rates to more than double in the absence of rate mitigation. Plans for rate mitigation are currently unclear.

1.1.5 Risk and Return

A central issue in this Application is Newfoundland Power's cost of capital.

The Board will consider an appropriate capital structure for ratemaking purposes and an appropriate return on common equity invested in the Company. In addition, the Board will again consider the use of an automatic adjustment formula to establish Newfoundland Power's annual cost of equity following the 2020 test year.

Some of the Company's business risks have persisted over the longer term. One example is the harsh weather conditions experienced throughout Newfoundland Power's service territory. Another example is the demographics of the Company's service territory. The provincial population is declining and aging faster than the Canadian average. This is expected to stifle economic growth.

Other business risks have become more pronounced since Newfoundland Power's last general rate application. The provincial economy has declined. All key economic indicators have experienced a downturn, including Gross Domestic Product, employment and housing starts. The downturn in the provincial economy is reflected in the Company's energy sales.

This economic downturn is occurring at a time when customers are expecting significant rate increases related to Nalcor Energy's Muskrat Falls project. In Newfoundland Power's view, the continuation of a struggling provincial economy and the commissioning of Nalcor Energy's Muskrat Falls project contribute to an above-average business risk for the Company. This is substantiated by expert evidence filed with this Application.

1.2 APPLICATION PROPOSALS

1.2.1 2019 and 2020 Revenue Requirements

In this Application, Newfoundland Power is requesting an average increase in current customer rates of approximately 1.2%, effective March 1, 2019. This rate increase is primarily the result of 3 changes in the Company's forecast cost of service.

The first change reflects a proposed increase in the Company's return on equity. Expert evidence filed with this Application recommends a fair return on equity for Newfoundland Power in 2019 and 2020 is 9.5% on a common equity ratio of 45%. This is higher than the ratemaking return on equity of 8.5% approved by the Board from 2016 to 2018. The higher return on equity represents a 1.2% increase in the revenue required from customer rates.

The second change relates to changes in Newfoundland Power's costs since its last general rate application. This includes the cost of continued investment in the electrical system and increased operating costs. It also includes reduced costs related to employee future benefits and the effects of amortizations proposed in this Application. The net result of these changes is a 0.7% increase in the revenue required from customer rates.

The third change relates to the recovery of wholesale supply costs. A general rate application requires forecast electricity supply costs to be reconciled with forecast revenue from customer rates during the test period. Rebalancing 2019 and 2020 supply costs results in a 0.7% decrease in the revenue required from customer rates.

1.2.2 Customer Rates, Rules and Regulations

The Company proposes to apply the average rate increase outlined in this Application equally to all customer classes. Uniform increases in customer rates will continue to maintain class revenue-to-cost ratios within a range of 90% to 110%.

Newfoundland Power is proposing to introduce a new service offering for LED street and area lighting in 2019. The new service offering will provide customers with improved lighting quality that is more reliable and at a lower cost. Proposed LED street and area lighting rates would yield savings for customers of between 8% and 39% in comparison to the Company's existing service offering.

Newfoundland Power completed a review of its *Schedule of Rates, Rules and Regulations* ("Rules and Regulations") in 2018. A focus of the review was the Company's practices regarding the denial or disconnection of service for non-payment. The review showed Newfoundland Power's practices offer reasonable flexibility to customers. The review also showed these practices do not result in either an unreasonable number of disconnections or an unreasonable level of uncollectible bills expense, which is collected from all customers. The Company is not proposing any changes as a result of this review.

1.2.3 Other Proposals

Newfoundland Power is proposing the Board continue the suspension of an automatic adjustment formula to establish the Company's annual cost of equity following the 2020 test year. The long Canada bond yields form the basis of the operation of the formula. There has not been an appreciable change in long Canada bond yields since Newfoundland Power's last general rate application. Accordingly, the Company does not view current circumstances as warranting reinstatement of the formula.

SECTION 2: CUSTOMER OPERATIONS

2.1 OVERVIEW

Newfoundland Power manages its service delivery in the least-cost manner responsive to customers' expectations.

The Company's customer service costs were lower in 2017 than they were 20 years prior. This cost reduction was achieved while serving more customers and responding to a higher number of customer-initiated contacts. While costs have declined, customer satisfaction has remained reasonably consistent.

Customer interest in energy conservation remains high. The Company is at the midway point of implementing a 5-year conservation plan. Customers have achieved energy savings consistent with the plan.

The delivery of service to customers is guided by the Company's Rules and Regulations. The Rules and Regulations were reviewed in 2018 with a focus on the denial and disconnection of service for non-payment. No changes are proposed as a result of the review.

Newfoundland Power's electrical system provides reliable service to customers. The average duration of customer outages on the system has been ½ the Canadian average since 2008. The frequency of customer outages has been consistent with the Canadian average.

The Company is responsive to customer outages and customer-driven work requests. Newfoundland Power's average restoration time for unscheduled outages has been approximately ½ the Canadian average since 2008.

Technology-driven initiatives have allowed Newfoundland Power to balance cost management with meeting customers' expectations. Planning for the replacement of the Company's 25-year-old Customer Service System will ensure continuity in the customer service delivery function.

Operating costs are forecast to increase by approximately 2.1% per year between 2015 and 2020. Operating labour costs are forecast to increase by 1.7% per year over the same period. This increase is less than the Company's labour rate inflation and reflects a continued focus on operating efficiency.

Newfoundland Power continues to target a stable level of capital investment required to maintain the condition of the electrical system. These expenditures are consistent with the delivery of reliable service at least cost.

2.2 CUSTOMER SERVICE DELIVERY

2.2.1 Customer Expectations

Customer Contacts

Newfoundland Power expects to serve approximately 270,000 customers by 2020. Maintaining customer relationships is a fundamental aspect of customer service delivery and requires managing day-to-day contacts with customers. Customers primarily contact Newfoundland Power to obtain information related to accounts and billing, outages, and programs and services offered by the Company.[1]

Table 2-1 shows how customers initiated contact with Newfoundland Power over the period 2013 to 2017.

Table 2-1:
Customer-Initiated Contacts
2013 to 2017
(000s)

	2013	**2014**	**2015**	**2016**	**2017**
Telephone	451	467	427	418	580
Email	49	62	62	72	124
Website	1,005	2,487	1,445	1,748	2,843
Total	**1,505**	**3,016**	**1,934**	**2,238**	**3,547**

Customer-initiated contacts exceeded 3.5 million in 2017. This was approximately 18% greater than in 2014 when widespread outages, known as #darkNL, resulted in a high number of customer inquiries.[2]

The high number of customer-initiated contacts in 2017 was largely attributable to the Rate Stabilization Plan ("RSP") Refund.[3] The RSP Refund accounted for 23% of all customer-

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[1] For example, see *Table 2-3: Most Viewed Website Content*, page 2-8.

[2] The widespread outages in 2014 were caused by supply issues and a series of electrical system events. Approximately 75% of the Company's customers experienced outages from January 2-8, 2014. During this period, Newfoundland Power received 139,335 customer calls, 947,215 visits to its website, and 240 emails from customers.

[3] On September 2, 2016, the Board approved the Company's plan to refund to customers approximately $129 million (excluding HST) that had accrued in Hydro's RSP. As of May 2018, the Company had refunded approximately $122.5 million to 212,000 current and former Newfoundland Power customers.

initiated contacts handled by the Company in 2017.[4] The *RSP Refund Progress Report*, provided in *Volume 2, Supporting Materials*, *Reports, Tab 6*, summarizes Newfoundland Power's execution of the RSP Refund as of May 2018 and its forthcoming closeout.

Increasing Digital Communications

Advancements in technology influence customers' service expectations, including a growing expectation for digital communication.[5]

Newfoundland Power's digital communication channels include its website, email and social media accounts. While customers' use of telephonic channels to contact the Company has remained relatively consistent since 2013, digital communication channels have grown in popularity. Newfoundland Power has expanded and enhanced its digital communication channels in response to this development.

Email contacts from customers more than doubled between 2013 and 2017.[6]

Customers email the Company regarding account balances, payment arrangements and requests for field work, among other reasons. The Company improved its ability to respond to customer emails in 2017 by installing a new multichannel Contact Management System.[7] The new system

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[4] In 2017, RSP Refund-related contacts accounted for approximately: (i) 666,000 website visits; (ii) 134,000 customer calls; and (iii) 23,000 emails. (666,000 + 134,000 + 23,000) / 3,547,000 = 0.23, or 23%.

[5] Gartner Inc. notes: *"Customer expectations for self-service through digital channels continue to rise, and the call center needs to evolve into a multichannel customer engagement center that includes mobile, social and emerging voice channels."* See *Optimizing Foundational Technology in Utilities Primer for 2018*, January 9, 2018, page 3.

[6] 124,000 / 49,000 = 2.5. See *Table 2-1: Customer-Initiated Contacts*, page 2-3.

[7] Implementation of a new Contact Management System was described in Newfoundland Power's *2016 Capital Budget Application, Report 6.2: 2016 System Upgrades*, page 2, *et. seq.*

allows Customer Service Representatives to efficiently switch between responding to customers' calls and emails. This ensures a timely response to customers using both telephone and email communication.

Visits to the Company's website more than doubled between 2013 and 2017.[8]

Customers are increasingly using mobile devices when visiting Newfoundland Power's website. Visits to the mobile version of the Company's website accounted for ½ of all website visits in 2017. Newfoundland Power re-launched its website to better serve customers in January 2018.[9] The new website allows customers to more easily view content and use self-service options on mobile devices. The implementation of a new Outage Management System in 2019 will allow customers to access real-time outage-related information via the website.[10]

Since 2012, the Company has used social media to share outage-related information with customers and promote available programs and services, including energy conservation information.[11] Newfoundland Power's total social media subscribers have increased each year since initial implementation, with over 44,000 total subscribers at year-end 2017.[12] The increase in subscribers is an indication of customers' growing preference for digital communication.

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8 2,843,000 / 1,005,000 = 2.8. See *Table 2-1: Customer-Initiated Contacts*, page 2-3.

9 The redesign of the Company's website is described in Newfoundland Power's *2016 Capital Budget Application, Report 6.1: 2016 Application Enhancements*, page 5, *et. seq.*

10 The Company's plan for replacing its Outage Management System is described in its *2018 Capital Budget Application, Report 5.5: Outage Management System Replacement and Enhancement Report*.

11 The Company also shares outage-related information with customers via an outage alert system that sends text messages to customers' mobile devices. Approximately 9,000 customers were subscribed to this service at year-end 2017.

12 Social media subscribers include followers of the Company's Facebook and Twitter accounts. In 2017, there were approximately 31,000 subscribers to Newfoundland Power's Twitter account and 13,300 subscribers to the Company's Facebook account.

2.2.2 Balancing Costs and Service

Service Efficiencies

Customer service costs include the day-to-day cost of interacting with customers. This includes the cost of operating the Customer Contact Centre, maintaining Newfoundland Power's digital platforms, and deploying customer service staff throughout the Company's service territory.

Over the 20-year period from 1998 to 2017, the number of customers served by Newfoundland Power increased by approximately 54,000 and customer-initiated contacts increased by approximately 2.4 million.[13] Over the same period, the Company reduced its customer service costs by approximately 8%.[14]

Newfoundland Power has implemented technology-driven initiatives of various scales to balance its customer service costs and meet customers' expectations.

In 2016, the Company began accelerating the deployment of Automated Meter Reading ("AMR") meters.[15] Virtually all meters in Newfoundland Power's service territory were automated by the end of 2017. This automation allows the Company to more efficiently read the approximately 254,000 customer meters in its service territory.[16] As a result, meter reading

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[13] In 1998, the Company received approximately 354,000 contacts from customers, all via telephone. This compares to approximately 2.7 million contacts received in 2017, excluding contacts regarding the RSP Refund.

[14] Newfoundland Power's customer service costs were approximately $8.7 million in 1998. This compares to $8.0 million in 2017. ($8,700,000 – $8,000,000) / $8,700,000 = 0.08, or 8%.

[15] The Company's accelerated deployment of AMR meters is described in Newfoundland Power's *2016 Capital Budget Application, Report 4.4: 2016 Metering Strategy*.

[16] Newfoundland Power maintained 426 meter reading routes in 2015. The Company reduced the required number of routes to 143 by year-end 2017. The reduction in routes reflects the more efficient meter reading process provided through automation.

operating costs were reduced by approximately 65%, or \$1.8 million, between 2012 and 2017.[17] These cost savings are reflected in the Company's proposed customer rates for 2020. The automation of meter reading has also substantially reduced the need for customer billing estimates.[18]

Newfoundland Power has continued to promote paperless billing ("ebills") to customers. ebills are generated and distributed automatically through the Company's Customer Service System. This process is more efficient and cost-effective than paper billing.[19]

Table 2-2 shows annual participation in ebills for the period 2013 to 2017.

Table 2-2:
ebills Participation
2013 to 2017

	2013	**2014**	**2015**	**2016**	**2017**
Customers Enrolled	63,453	72,277	89,072	101,273	113,150

Participation in ebills has increased each year since 2013. Over 113,000 customers received their bills electronically in 2017. Newfoundland Power has the second highest proportion of

17 Meter reading operating costs were approximately \$2,810,000 in 2012 and \$980,000 in 2017. (\$2,810,000 – \$980,000) / \$2,810,000 = 0.65, or 65%.

18 Between 2016 and 2017, annual billing estimates were reduced by approximately 46%. Billing estimates are still required under certain circumstances. For example, estimates are completed during periods of poor weather conditions and for customers in cottage areas.

19 The cost of issuing an ebill is approximately \$10.18/year per customer less than a paper bill. This amount reflects avoided printing, paper, envelope and postage charges. It does not include embedded labour and equipment costs associated with printing bills, as the Company is still required to incur those costs to provide paper bills to some of its customers.

electronically billed customers in the Canadian electric utility sector.[20] Savings from ebills are reflected in the Company's proposed customer rates for 2020.[21]

The Company's website is currently the most used communication channel among customers, accounting for approximately 80% of all customer-initiated contacts in 2017.[22]

Table 2-3 shows the most viewed content on Newfoundland Power's website based on a review of the 50 most viewed pages in 2017.[23]

Table 2-3:
Most Viewed Website Content
2017
(000s)

	Account Related	Outage Related	RSP Refund	Other[24]
Page Views	3,360	2,402	521	495

The most viewed content on the Company's website in 2017 related to customer accounts. This includes self-service options that allow customers to view their balance and establish payment

[20] A quick poll issued by the Canadian Electricity Association ("CEA") in April 2017 showed Newfoundland Power has the highest percentage of customers enrolled in ebills of the 10 survey respondents. The survey respondents were NB Power, Manitoba Hydro, FortisBC, London Hydro, Nova Scotia Power, Newfoundland and Labrador Hydro, Hydro Ottawa, Hydro One, Toronto Hydro, and Newfoundland Power. BC Hydro did not complete the survey. In January 2018, BC Hydro confirmed their ebills participation rate was 49%, which is higher than that of Newfoundland Power (approximately 43% in the first quarter of 2018).

[21] Postage costs are forecast to decrease by approximately 15%, or $230,000, between 2015 and 2020. This reflects a forecast increase in ebills participation, partially offset by expected postal rate increases of 15.5% over this period and a forecast increase in total customers of 3.6%.

[22] Newfoundland Power received approximately 3,547,000 total contacts from customers in 2017, 2,843,000 of which were via the website. 2,843,000 / 3,547,000 = 0.80, or 80%.

[23] Each visit to the Company's website can generate multiple page views. The total number of page views is therefore substantially higher than the total number of website visits. Landing pages, which serve to direct customers to available information, were excluded from the analysis.

[24] "Other" includes views on pages such as Contact Us and Career Opportunities.

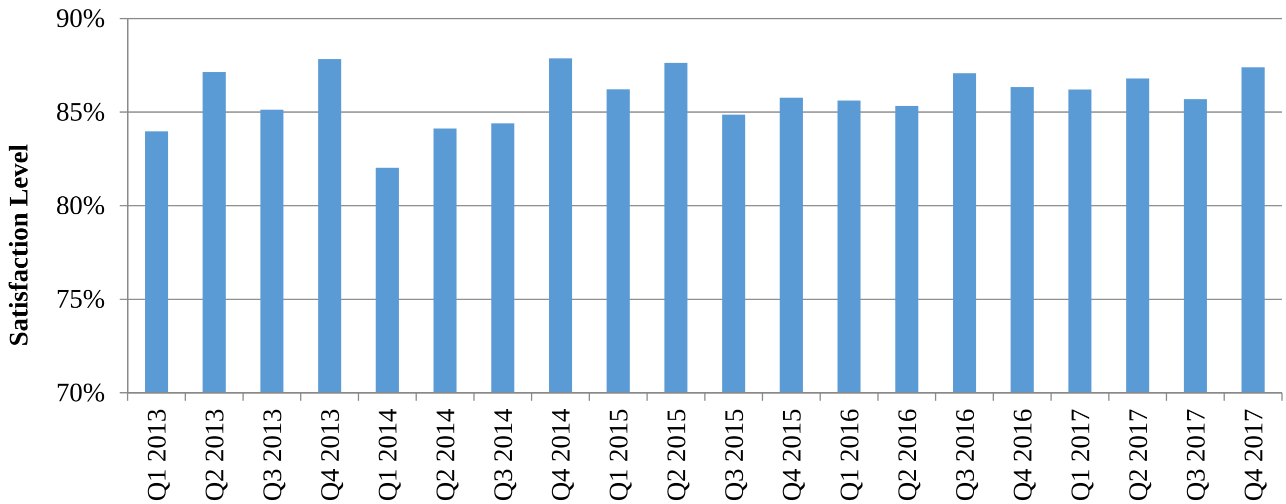
arrangements online. Providing such self-service options is more efficient and cost-effective than other communication channels.[25]

Customer Satisfaction

Newfoundland Power surveys its customers each quarter to determine their satisfaction with the Company's service. These surveys provide a broad measure of customers' general satisfaction with the Company's service delivery.

Figure 2-1 provides quarterly results for Newfoundland Power's customer satisfaction index for the period 2013 to 2017.

Figure 2-1:
Customer Satisfaction Index
2013 to 2017



[25] The cost of a call handled by a Customer Service Representative is over $8 per call. The cost of a contact via the website is less than 10¢ per contact.

Customer satisfaction was lower during the first quarters of 2013 and 2014 than other quarters during the period. Both of these quarters were marked by significant customer outages.[26]

The average level of customer satisfaction across all quarters was 86% in 2013, 85% in 2014, 86% in 2015 and 2016, and 87% in 2017.

Ensuring Continuity in Customer Service Delivery

Newfoundland Power's customer service delivery function includes 3 key pillars: (i) customer account management and billing; (ii) customer communications and contact management; and (iii) program and service delivery, including energy conservation programs. The customer service delivery function evolves over time as customers' expectations, regulatory requirements and industry practices change.

The Company's Customer Service System has been the primary technology underpinning Newfoundland Power's customer service delivery for 25 years. The system supports each pillar of the Company's customer service delivery. It stores and processes the vast majority of customer information, including monthly bills.[27] It provides a record of customer inquiries and is used to maintain customer relationships. Automation provided by the system has allowed the Company to balance operating efficiencies with meeting customers' service expectations.[28]

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[26] A significant outage occurred from January 11-13, 2013 caused by a loss of Hydro's Holyrood Thermal Generating Station ("Holyrood") Unit #1. A loss of supply and a series electrical system events from January 2-8, 2014 also caused widespread outages to Newfoundland Power customers.

[27] The Customer Service System stores information related to over 260,000 active customer accounts and over 1 million inactive accounts. The system also generates approximately 3 million customer bills each year and manages all customer payments.

[28] Examples of automation include: (i) the automatic issuance of ebills to customers; (ii) the provision of customer self-service options through integration with the Company's website and telephone system; and (iii) the automatic generation of customer correspondence and calls relating to collections processes.

The Customer Service System was custom-built in 1993 at a cost of approximately $10.2 million, with an expected service life of 20 years.[29] While Newfoundland Power expects to extend the system's service life to 30 years, the risk of technical and functional obsolescence is expected to increase beyond this timeframe.[30] This is consistent with industry trends.[31]

Replacing the Company's Customer Service System is a once-in-a-generation effort. Managing this requires an assessment of Newfoundland Power's customer service delivery function and developing a plan to ensure continuity within this function.

Newfoundland Power intends to complete this assessment over the 2018 to 2020 timeframe. Table 2-4 provides the costs associated with the assessment.

Table 2-4:
Customer Service Delivery Assessment
Project Costs
($000s)

	2018F	**2019F**	**2020F**
Labour	90	442	408
Other	60	175	130
Total	**150**	**617**	**538**

[29] Newfoundland Power has completed various upgrades and enhancements to the Customer Service System since its initial implementation. In 1998, the Company upgraded the system architecture. This upgrade was necessary to extend the life of the system and allow it to be supported internally. The system was also upgraded: (i) in 2003 to support the Equal Payment Plan; (ii) in 2011 to support the Provincial Government's residential energy rebate; and (iii) in 2016 to administer the RSP Refund. Such modifications have resulted in a highly customized system that is unique to Newfoundland Power.

[30] The hardware, operating system and programming languages used to support the Customer Service System are no longer commonplace in the industry and are expected to further diminish. Additionally, due to employee retirements, the Company expects its internal support of the system to decline over the next 5 years. The materialization of such risks would limit the Company's ability to repair, modify and upgrade the system.

[31] TMG Consulting, a consulting firm specializing in customer information systems, notes that approximately 51% of surveyed utilities anticipate replacing their customer information systems within the next 6 years. See TMG Consulting, *CIS Replacement Risk Mitigation*, April 2016, page 6.

The assessment is estimated to cost approximately $1.3 million over 3 years. It will provide a plan for replacing the Customer Service System and ensuring continuity in the customer service delivery function. This timeline is consistent with implementing a new customer service solution within the next 5 years.[32]

2.2.3 Customer Conservation

Five-Year Conservation Plan: 2016-2020

Newfoundland Power and Hydro began implementing an updated 5-year energy conservation plan in 2016.[33] The *Five-Year Conservation Plan: 2016-2020* outlined 4 primary changes to customer conservation programming. These were: (i) expansion of the Business Efficiency Program and Instant Rebates program; (ii) introduction of a new residential Benchmarking program to encourage behavioural change among customers; (iii) discontinuation of certain residential incentives; and (iv) development of an initiative to educate customers on mini-split heat pumps.[34]

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[32] The Company's *2018 Capital Plan* reflected this replacement timeframe: "*While the current versions of hardware, software and database technology should be supported throughout this capital plan period, commencing in 2021, the Company has included a project to commence the replacement of its Customer Service System.*" See page 19 of the *2018 Capital Plan*, provided with the Company's *2018 Capital Budget Application.*

[33] The *Five-Year Conservation Plan: 2016-2020* was provided as Tab 1 in *Volume 2, Exhibits & Supporting Materials* of the Company's *2016/2017 General Rate Application (1st Revision).*

[34] Order No. P.U. 18 (2016), page 46, lines 31-32, states: "*The Board is satisfied that Newfoundland Power's approach to conservation and demand management is appropriate and aligns with utility and customer interests.*"

Costs, Savings and Customer Participation

Table 2-5 shows energy savings and costs for Newfoundland Power's customer conservation programs for the period 2013 to 2017.

Table 2-5:
Customer Conservation Programs
2013 to 2017

	2013	**2014**	**2015**	**2016**	**2017**
Costs (000s)	$3,654	$5,289	$5,318	$7,639	$7,378
Energy Savings (GWh)	36.3	50.0	66.6	91.8	123.7

Annualized energy savings from customer conservation programs more than tripled from 2013 to 2017.[35] At a marginal cost of production at Holyrood of 12.0¢/kWh, energy savings of 123.7 GWh translates into avoided fuel costs of approximately $14.8 million in 2017.[36]

Customer conservation programs include both on-bill and instant rebates.[37] Participation in on-bill rebate programs increased by approximately 40% from 2013 to 2017.[38] Approximately 7,300 on-bill rebates were provided to customers in 2017. The Instant Rebates program was introduced in 2014. Over 2.4 million instant rebates have been provided to customers since 2014.

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35 123.7 / 36.3 = 3.4.

36 Hydro's Holyrood Thermal Generating Station is typically the marginal production facility on the Island Interconnected System. Based on information provided by Hydro, dated April 9, 2018, the cost of fuel associated with electricity generated at Holyrood, including losses to the end user, was $0.120/kWh during 2017. The average cost of fuel used at Holyrood was $68.60 per barrel.

37 On-bill rebates are credited to a customer's monthly bill after submitting the required documentation and are available for products such as insulation, heat recovery ventilators, and thermostats. Instant rebates provide at-the-cash discounts on smaller energy-efficient products, such as LED bulbs.

38 There were 5,246 participants in on-bill rebate programs in 2013 and 7,327 in 2017. (7,327 – 5,246) / 5,246 = 0.40, or 40%.

The Company has increased its efforts to educate customers on energy conservation. The residential Benchmarking program was rolled out in 2016 to approximately 50,000 customers. This program provides customers with reports on their home energy use and how it compares to similar homes. Participants also receive tips and advice on low-cost ways to save energy.

Customer education efforts have also included the launch of an initiative to educate customers on heat pumps in 2016. Through this initiative, the Company provides information to help customers understand whether a heat pump is right for their home, how to select an efficient model, and how to choose a certified installer. This information is available to all customers through the takeCHARGE website, social media, bill inserts, and other channels.[39]

Future Customer Conservation Programming

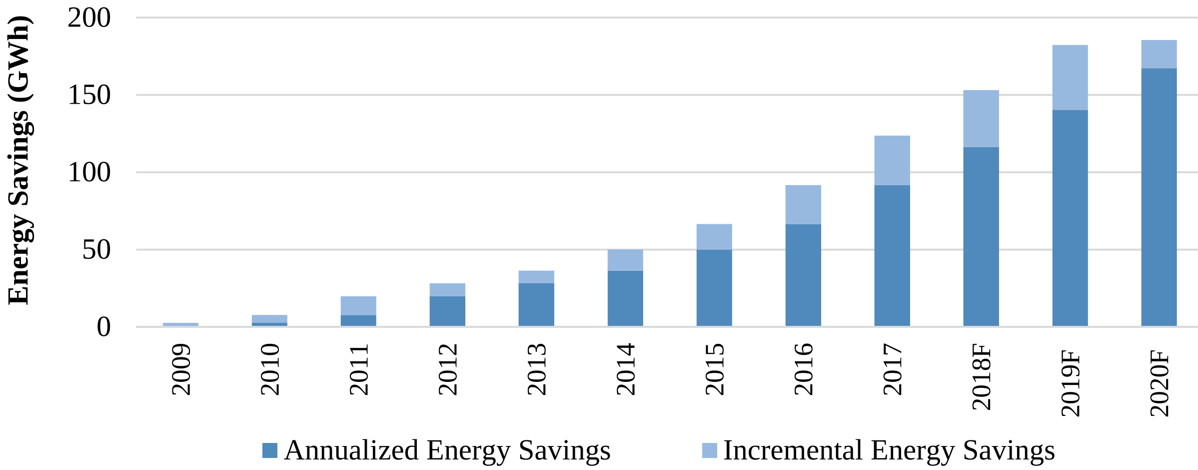
The Company is currently at the midway point of implementing the *Five-Year Conservation Plan: 2016-2020.* Expected changes in programming over the remainder of the plan include: (i) conclusion of the Instant Rebates program and residential Benchmarking program in 2019; (ii) continued expansion of the Business Efficiency Program; and (iii) increased emphasis on customer education through social media, websites, and customer events.[40]

[39] The Heat Pumps page was the most visited content on the takeCHARGE website in 2017, with approximately 78,000 views.

[40] The Instant Rebates program was originally scheduled to conclude in 2018. However, market research commissioned in 2017 showed significant room for growth in the residential LED market, with approximately 4.2 million sockets that could be converted to more efficient lighting. The Instant Rebates program was therefore extended for 1 additional year.

Figure 2-2 shows forecast annualized energy savings for the period 2009 to 2020F, including the incremental savings added each year through continued programming.[41]

Figure 2-2:
Customer Conservation Programs
Energy Savings
2009 to 2020F



Newfoundland Power is forecasting that continued conservation programming will add energy savings of: (i) 36.8 GWh in 2018; (ii) 41.9 GWh in 2019; and (iii) 18.3 GWh in 2020.[42] A reduction in incremental energy savings in 2020 reflects the planned conclusion of the Instant Rebates program and residential Benchmarking program in 2019.[43]

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41 Energy savings from customer conservation programs are realized over many years. The Company tracks both the incremental savings achieved through the programs implemented each year, as well as the total annualized savings over the lifetime of the programs. For example, insulation installed by a customer is expected to yield energy savings for 25 years.

42 The energy savings indicated represent *gross* energy savings achieved by customers in each year. These savings reflect all technologies installed by participating customers since program implementation. *Gross* energy savings from 2009 to 2020 are forecast to be approximately 947.6 GWh. *Net* energy savings would reflect adjustments for: (i) the timing of customer installations giving rise to the energy savings; and (ii) program *free ridership* (an estimate of participants who would have chosen the more efficient product without the program). *Net* savings from 2009 to 2020 are forecast to be approximately 664.8 GWh.

43 The Benchmarking program is not expected to be cost-effective following a forecast decline in the marginal cost of electricity in 2020. Conclusion of the Instant Rebates program in 2019 reflects forecast market saturation of LED light bulbs.

Table 2-6 shows forecast costs for the Company's customer conservation programs until the conclusion of the 5-year plan in 2020.

Table 2-6:
Customer Conservation Programs
Costs
2016 to 2020F
($000s)

	2016	**2017**	**2018F**	**2019F**	**2020F**
General	439	620	623	825	693
Program	7,200	6,758	6,701	6,895	4,065
Total	**7,639**	**7,378**	**7,324**	**7,720**	**4,758**

Costs related to customer conservation programs are forecast to average approximately $7.5 million per year from 2016 to 2019. Costs are expected to decline to approximately $4.8 million in 2020.

Newfoundland Power evaluated the cost-effectiveness of its existing programs.[44] The evaluation shows conservation programs continue to be the least-cost option of providing service to customers.[45]

[44] All programs included in the *Five-Year Conservation Plan: 2016-2020* were screened using the Total Resource Cost test and the Program Administrator Cost test. These are standard industry metrics that assess the cost-effectiveness of conservation programs and facilitate program planning. The use of these tests was approved by the Board in Order No. P.U. 18 (2016). Test results were provided in Schedule C and Schedule E of the *Five-Year Conservation Plan: 2016-2020*.

[45] The Levelized Utility Cost test is a standard industry metric that discounts future energy savings to a present value. It considers *utility* program costs (i.e. development, marketing, incentives and administration costs), but not customer costs. The Company has used the Levelized Utility Cost test to evaluate its customer conservation programs since 2016, including in its annual *Conservation and Demand Management Report* filed with the Board. In response to Request for Information CA-NLH-081 of Hydro's *2017 General Rate Application*, Hydro provided updated marginal cost forecasts for 2018 and 2019. The updated forecasts reflect: (i) use of the Holyrood Thermal Generating Station on the margin for the first half of 2018; and (ii) market opportunity cost thereafter reflecting the projected availability of the Labrador-Island Link on July 1, 2018. The updated marginal energy costs are approximately 7.96¢/kWh in 2018 and 5.01¢/kWh in 2019. The Levelized Utility Cost of Newfoundland Power's customer conservation programs is expected to be 2.60 ¢/kWh for the period 2018 to 2020. This is below Hydro's forecast marginal energy costs for 2018 and 2019.

The marginal cost outlook on the Island Interconnected System is uncertain and will be reviewed during Hydro's cost of service methodology review scheduled to begin in late 2018.[46] Newfoundland Power will adjust its evaluation of customer conservation programs as more information becomes available on future marginal costs.

2.2.4 2018 Rules and Regulations Review

The Company's Rules and Regulations outline the basic standards governing the provision of electrical service to customers. On November 21, 2017, the Board directed Newfoundland Power to review its Rules and Regulations and file a report addressing 4 specific issues: (i) denial and disconnection of service for non-payment; (ii) disconnection in winter; (iii) landlord and tenant responsibilities; and (iv) the protection of personal information. The Board indicated the Company's next general rate application would provide an opportunity for a full review of these issues.

The results of the review are provided in *Volume 2, Supporting Materials, Reports, Tab 8*.[47]

A survey conducted as part of the review shows Newfoundland Power's Rules and Regulations are comparable to utility policy frameworks throughout Canada and are applied in a manner consistent with Canadian utility practice.

The review shows Newfoundland Power's collections practices offer reasonable flexibility to customers and ensure the denial or disconnection of service is a last resort in customer service

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[46] See response to Request for Information NP-NLH-239 of Hydro's *2017 General Rate Application*.

[47] A copy of the *2018 Rules and Regulations Review* was filed with the Board on April 12, 2018.

delivery. The review also shows the Company's collections practices do not result in either an unreasonable number of disconnections or an unreasonable level of uncollectible bills expense, which is collected from all customers.

Based upon this review, Newfoundland Power has concluded that its existing Rules and Regulations continue to be relevant, serve the needs of the Company and its customers, and maintain an equitable balance in delivery of service. Accordingly, no changes are proposed as a result of this review.

2.3 OPERATIONS AND RELIABILITY MANAGEMENT

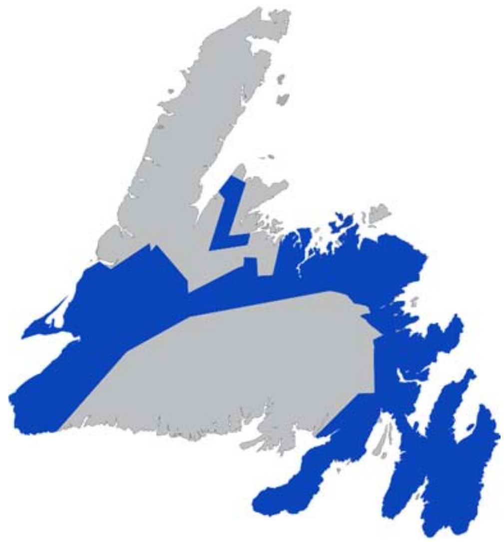
2.3.1 System Overview

Newfoundland Power has been the primary distributor of electricity on the Island Interconnected System for over 50 years.[48] The Company currently serves approximately 87% of all customers in Newfoundland and Labrador.

[48] In 1966, 5 investor-owned utilities were amalgamated into Newfoundland Power to serve the majority of customers on the island portion of Newfoundland and Labrador.

Figure 2-3 shows Newfoundland Power's service territory.

Figure 2-3:
Newfoundland Power's Service Territory



The Company's service territory is vast at approximately 70,000 km^2. It is almost 1,000 kilometres from Trepassey on the Avalon Peninsula, to Port aux Basques on the southwest coast. It is over 300 kilometres from Grand Bank on the Burin Peninsula to Bonavista.

The Company owns and operates approximately 10,400 kilometres of distribution line, 2,100 kilometres of transmission line, and 130 substations to serve customers throughout its service territory. On average, these assets have been in operation for approximately 30 years. This asset age is characteristic of a mature electrical system.

The Company operates 23 hydroelectric plants that generate approximately 439 GWh annually.[49] These plants have provided customers with low-cost electricity for over 100 years.[50] The Company also operates 3 combustion turbines and 2 diesel units. These generation assets are operated when necessary to support system reliability.

Newfoundland Power's generation assets produce approximately 7% of the energy required to serve the Company's customers. The remainder is purchased from Hydro. Hydro is the primary generator and transmitter of bulk electricity on the Island Interconnected System.

2.3.2 Electrical System Performance

General

Newfoundland Power's electrical system is constructed and maintained to meet or exceed national standards.[51] These standards ensure the electrical system operates safely and reliably under conditions the Company could reasonably expect to occur in its service territory ("normal operating conditions").

Electrical systems, including Newfoundland Power's, are not constructed or expected to fully withstand the impact of extreme weather conditions, including hurricanes, severe wind storms and ice storms. These events can cause extensive damage to the electrical system and may result

[49] Newfoundland Power's Normal Hydroelectric Production for 2018 was established as 439.1 GWh in correspondence to the Board dated January 31, 2018.
[50] The Company's Petty Harbour Hydroelectric Plant was commissioned in 1900.
[51] The primary engineering standard is the Canadian Standards Association ("CSA") standard *C22.3 No.1-15, Overhead Systems*. This standard guides the construction of overhead distribution and transmission systems.

in prolonged customer outages. Canadian utility reporting standards consider such conditions to be *significant events*.[52]

Utility reporting standards measure system reliability separately for: (i) normal operating conditions; and (ii) significant events.[53] This practice helps determine whether electrical systems perform to the standards to which they are designed and the reliability experienced by customers.

Normal Operating Conditions

Assessing the day-to-day reliability experienced by customers requires measuring both the duration and frequency of outages. This is necessary to determine whether customers experience an undue number of interruptions or prolonged periods without service.

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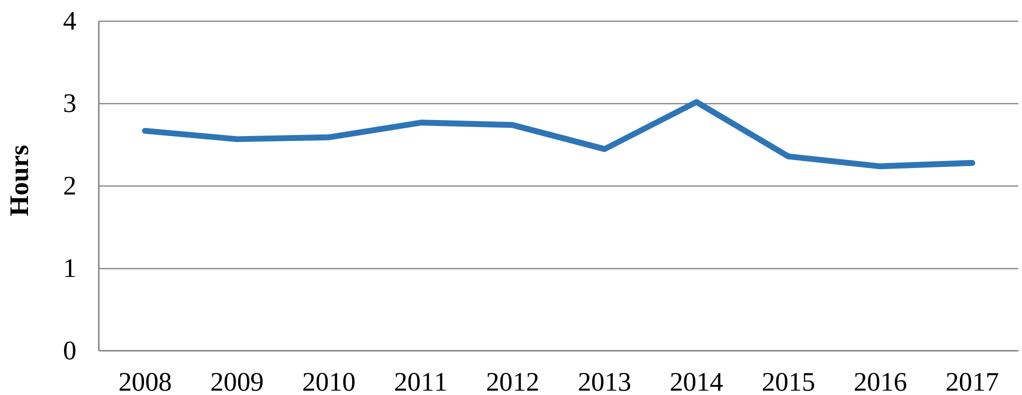
52 The CEA defines significant events as *"events that exceed reasonable design and/or operational limits of the electrical power system."*

53 Newfoundland Power calculates its reliability performance according to CEA guidelines. The CEA's recommended reporting standard is IEEE Std 1366 – 2012, contained within the *IEEE Guide for Electric Power Distribution Reliability Indices*. All reliability data calculated by the Company follows this reporting standard.

Figure 2-4 shows the average duration of outages ("SAIDI") experienced by Newfoundland Power's customers for the period 2008 to 2017 under normal operating conditions.[54]

Figure 2-4:
SAIDI
Newfoundland Power
Normal Operating Conditions
2008 to 2017

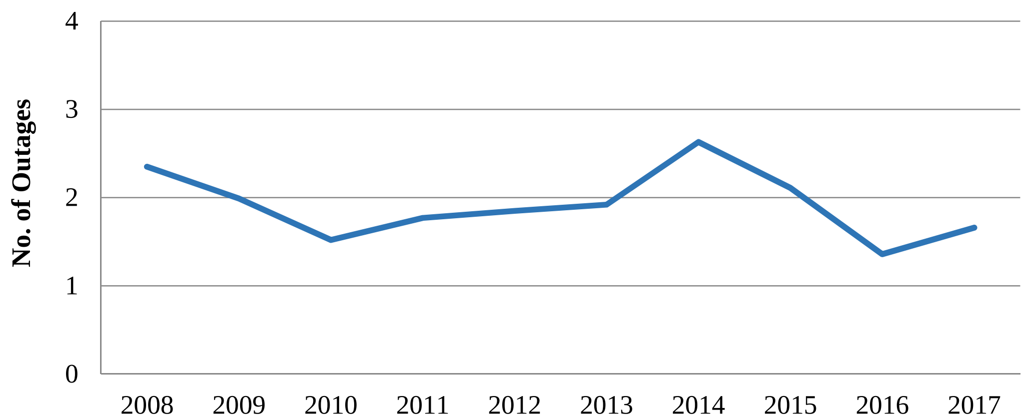


Under normal operating conditions, the duration of customer outages has remained relatively consistent since 2008, at approximately 2.3 to 3 hours per year.

[54] "SAIDI" denotes System Average Interruption Duration Index. It is a standard metric used to measure the duration of outages experienced by customers. SAIDI is calculated by dividing the total number of customer outage minutes by the total number of customers served. Newfoundland Power calculates SAIDI in accordance with CEA guidelines.

Figure 2-5 shows the average number of outages experienced by the Company's customers ("SAIFI") for the period 2008 to 2017 under normal operating conditions.[55]

Figure 2-5:
SAIFI
Newfoundland Power
Normal Operating Conditions
2008 to 2017



Under normal operating conditions, customers have experienced an average of between 1 and 3 outages per year since 2008. The higher number of customer outages in 2014 related to an increased incidence of high winds in the Company's service territory.[56]

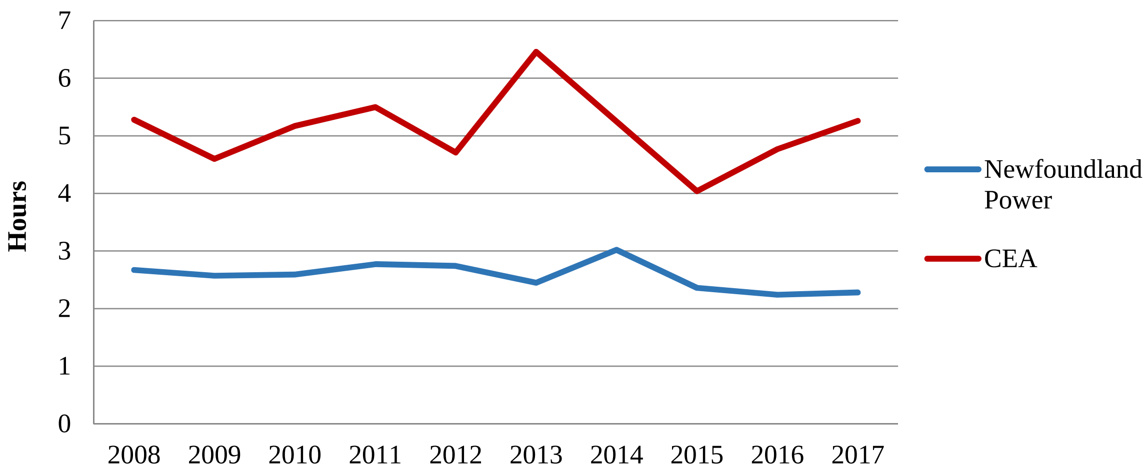
Comparing Newfoundland Power's system reliability to the Canadian average is a reasonable means to assess the Company's performance.

55 "SAIFI" denotes System Average Interruption Frequency Index. It is a standard metric used to measure the number of outages experienced by customers. SAIFI is calculated by dividing the total number of customer interruptions by the total number of customers served. Newfoundland Power calculates SAIFI in accordance with CEA guidelines.

56 In 2014, there was a total of 44 days when wind speeds in excess of 100 km/hr were experienced at 1 of 4 weather stations in the Company's service territory. This compares to an average of 17 days per year with wind speeds in excess of 100 km/hr for the 5 years ending in 2013.

Figure 2-6 shows Newfoundland Power's SAIDI under normal operating conditions in comparison to the Canadian average for the period 2008 to 2017.[57]

Figure 2-6:
SAIDI
Newfoundland Power vs. Canadian Average
Normal Operating Conditions
2008 to 2017

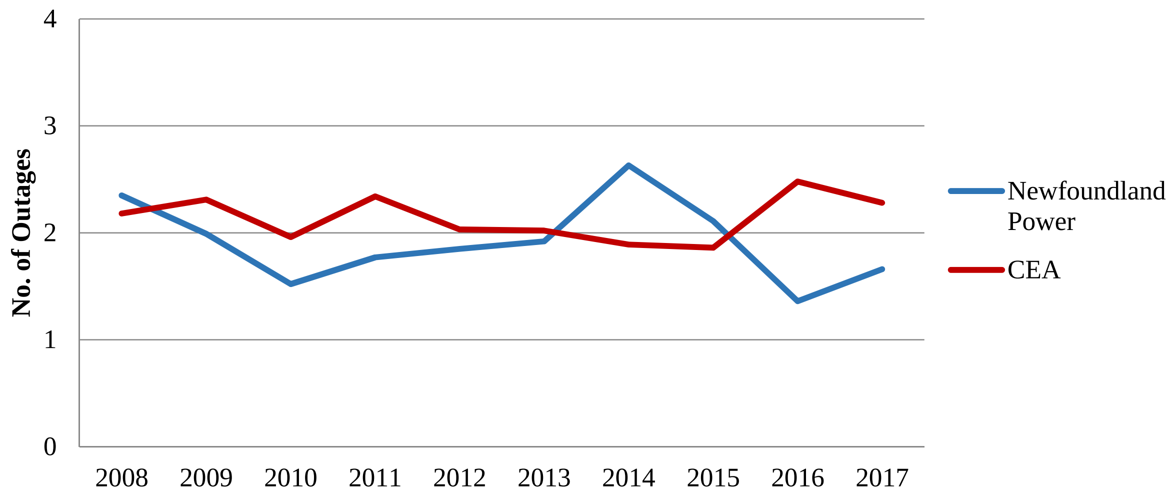


The average duration of outages experienced by the Company's customers has been approximately ½ the Canadian average since 2008.

[57] References to the Canadian average in *Section 2: Customer Operations* refer to Region 2 utilities that are members of the CEA. Region 2 utilities include Canadian utilities that serve a mix of urban and rural markets. These are ATCO Electric, BC Hydro, FortisAlberta, FortisBC, Hydro One, Hydro Quebec, Manitoba Hydro, Maritime Electric, NB Power, Newfoundland and Labrador Hydro, Newfoundland Power, Newmarket-Tay Power Distribution, Nova Scotia Power, Northwest Territories Power Corporation, Sask Power, Veridian Connections, Waterloo North Hydro, Yukon Electrical Co. and Yukon Energy.

Figure 2-7 shows Newfoundland Power's SAIFI under normal operating conditions in comparison to the Canadian average for the period 2008 to 2017.

Figure 2-7:
SAIFI
Newfoundland Power vs. Canadian Average
Normal Operating Conditions
2008 to 2017



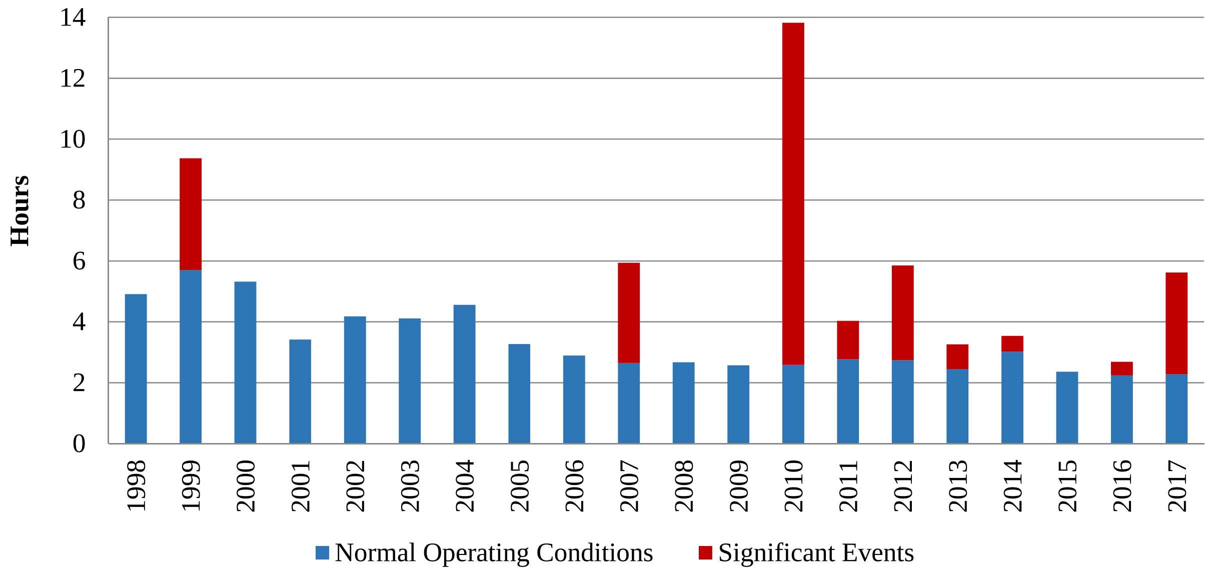
The average number of outages experienced by Newfoundland Power's customers has been broadly consistent with the Canadian average since 2008.

Significant Events

Significant electrical system events in Newfoundland and Labrador are typically caused by extreme weather, such as hurricanes, severe wind storms and ice storms. Significant events generally affect the duration of outages more than the frequency of outages. For example, a hurricane may result in a single outage that lasts several days. Such events often exceed the design parameters of the Company's electrical system and may cause widespread damage.

Figure 2-8 shows the average duration of outages experienced by Newfoundland Power's customers for the 20-year period from 1998 to 2017, including significant events.[58]

Figure 2-8:
SAIDI
Newfoundland Power
Including Significant Events
1998 to 2017



Over the 10-year period from 1998 to 2007, the Company recorded 2 years in which customer outages were caused by significant events. Over the most recent 10-year period, significant events caused customer outages in 7 years.

Each of the significant events that occurred over the most recent 10-year period involved winds in excess of 100 km/hr. The most substantial of these was in 2010 when Hurricane Igor and a severe ice storm on the Bonavista Peninsula caused significant damage to the Company's

[58] Figure 2-8 does not include outages caused by a loss of supply from Hydro.

distribution and transmission systems. Other events include Tropical Storm Leslie in 2012, which saw winds gusting to 133 km/hr, and a severe wind storm in March 2017, during which winds gusted to 180 km/hr.

Reliability Management

System reliability largely reflects the general condition of the electrical system. Deteriorated or defective equipment is more prone to failure and more likely to result in customer outages. The majority of customer outages occur at the distribution level.[59]

The Company completes routine inspections of its electrical system to proactively identify deterioration and necessary repairs or replacements.[60] Repairs or replacements are prioritized based on a combination of factors, including risk of failure, any identified safety issues, and the likelihood of customer outages. These inspection and maintenance programs have contributed to a reduction in equipment failures, which supports system reliability.[61]

Over 50% of the Company's annual capital expenditures are focused on the replacement or refurbishment of existing assets. For example, each year Newfoundland Power analyzes the reliability performance of its 306 distribution feeders. The worst-performing feeders are assessed to determine whether repairs are necessary to improve reliability performance. The

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59 For Region 2 utilities, the CEA notes that 85% of outage hours in the last 5 years are attributable to distribution-level outages. See *2017 Service Continuity Data on Distribution System Performance in Electrical Utilities.*

60 Newfoundland Power's inspection and maintenance practices were detailed in the Company's *2016/2017 General Rate Application (1st Revision), Volume 1, Application and Company Evidence, Section 3: Operations,* pages 3-10 to 3-11.

61 From 2013 to 2017, Newfoundland Power experienced approximately 900 equipment failures per year. This is below the 5-year average of approximately 1,300 equipment failures per year between 2008 and 2012. Service wire failures to individual premises are not included in this assessment as they are not subject to the Company's annual inspection and maintenance programs.

Company has implemented this program since 1998 at an average annual capital budget of $1.0 million.[62]

A review of Newfoundland Power's operations in 2014 found the Company uses an effective combination of periodic inspections, maintenance and capital programs. The review also concluded these programs have materially contributed to improved reliability.[63]

2.3.3 Field Responsiveness

Field Response Performance

As the primary distributor of electricity on the Island Interconnected System, Newfoundland Power must be responsive to customer outages and customer-driven work requests. This is necessary to ensure system reliability and to meet customers' service expectations.

Newfoundland Power compares its responsiveness to other utilities using the Customer Average Interruption Duration Index ("CAIDI"). CAIDI is a measure of the average time it takes to restore service following an unscheduled outage.[64]

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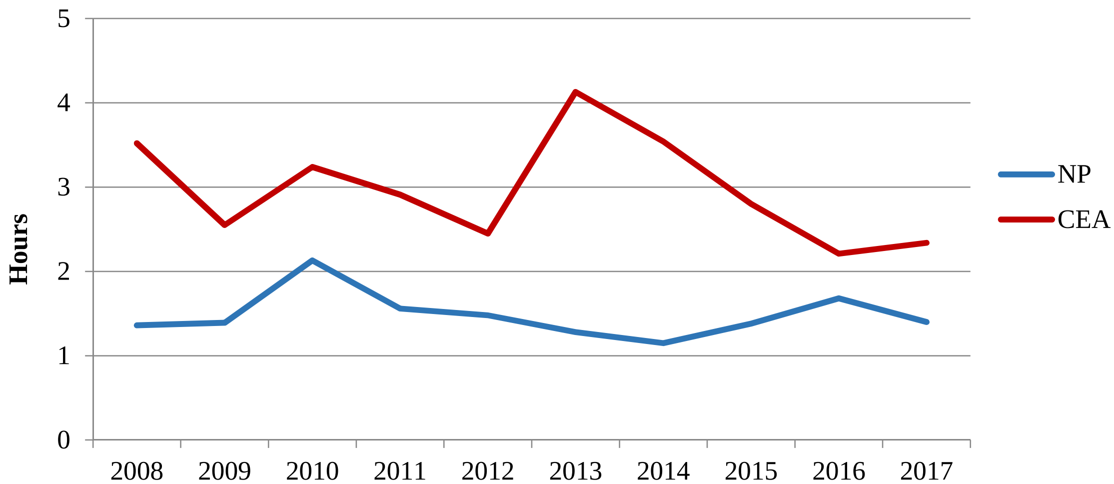
[62] In 2018, Newfoundland Power's Distribution Reliability Initiative involves capital work on 3 distribution feeders: Kenmount Substation feeder KEN-03; Summerford Substation feeder SUM-02; and Trepassey Substation feeder TRP-01. Combined, the total cost of these projects is approximately $1.8 million.

[63] See Liberty Consulting Group, *Report on Island Interconnected System to Interconnection with Muskrat Falls Addressing Newfoundland Power*, page ES-2.

[64] CAIDI is the restoration time measure used by the CEA. In arithmetic terms, CAIDI is expressed as SAIDI / SAIFI.

Figure 2-9 compares Newfoundland Power's average restoration time to the Canadian average for the period 2008 to 2017.

Figure 2-9:
CAIDI
Newfoundland Power vs. Canadian Average
Unscheduled Outages
2008 to 2017



Newfoundland Power's average restoration time to unscheduled outages has been approximately ½ the Canadian average since 2008.[65]

The Company maintains operational performance targets to ensure a reasonable level of responsiveness to customers. Newfoundland Power aims to complete new service connections within 10 business days. The Company's target is to meet this timeframe for at least 85% of new service connections.

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65 From 2008 to 2017, the Company's average restoration time was 1.48 hours. Over this period, the CEA average was 2.97 hours. 1.48 / 2.97 = 0.50, or 50%.

Newfoundland Power has met or exceeded its target for completing new service connections in each of the last 3 years.[66] From 2012 to 2014, the Company's average response time for completing new service connections was approximately 12.28 days. Over the most recent 3-year period, the Company's average response time was approximately 8.19 days.

Overall, Newfoundland Power has maintained a reasonable level of responsiveness to customer outages and customer-driven work requests.

Field Response Capabilities

Newfoundland Power maintains its field responsiveness through a combination of: (i) workforce management; (ii) operational technologies; and (iii) electrical system automation.

Maintaining a skilled and adequately resourced workforce is necessary to enable a reasonable level of responsiveness to customers. For example, the Company employs Powerline Technicians throughout its service territory to respond to customer outages and complete work on the electrical system. In 2009, Newfoundland Power forecasted a high number of retirements among its journeyperson Powerline Technicians. The Company subsequently hired an increased number of apprentices. By managing this demographic transition, Newfoundland Power has maintained continuity in its workforce and field response capabilities.[67]

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[66] A combination of factors affect the Company's responsiveness to new service connections, including the total number of new service connections to be completed. Gross customer connections were: 5,286 in 2012, 5,280 in 2013, 4,308 in 2014, 3,786 in 2015, 3,528 in 2016, and 3,271 in 2017. The Company's target performance was: 76% in 2012, 79% in 2013, 83% in 2014, 85% in 2015, 87% in 2016, and 90% in 2017.

[67] In 2013, Newfoundland Power employed 115 journeyperson Powerline Technicians and 38 apprentices. In 2017, the Company employed 128 journeypersons and 12 apprentices. This is consistent with the 128 journeypersons and 11 apprentices employed in 2007. This demographic transition was detailed in the Company's *2010 General Rate Application, Section 2: Customer Operations*, pages 2-14 to 2-15.

Newfoundland Power deploys its workforce using a combination of operational technologies.[68] A technology-based, centralized dispatching process was implemented in 2014.[69] A modern SCADA system and Geographic Information System were implemented in 2016.[70] Together, these systems provide information on the status of the electrical system, where to dispatch crews when issues arise, and the progress of ongoing field work. These capabilities support a timely response to customer outages and customer-driven work requests. The modernization of such technologies aligns with best utility practice.[71]

Newfoundland Power's field response capabilities are supported by automation throughout the distribution system.[72] The percentage of automated feeders within the distribution system increased to nearly 80% in 2017.[73] The number of downline reclosers installed on the

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[68] The Company's operational technologies were detailed in Newfoundland Power's *2016/2017 General Rate Application (1st Revision), Volume 1, Application and Company Evidence, Section 3: Operations*, pages 3-19 to 3-21.

[69] Centralized dispatching technologies include a Workforce Management System, Automatic Vehicle Location System, and mobile technology in line trucks. A centralized team uses these technologies to coordinate and monitor the day-to-day completion of field work throughout the Company's service territory.

[70] "SCADA system" denotes Supervisory Control and Data Acquisition System. Together, the SCADA system and Geographic Information System provide a geographic view of customer outages and where field crews must be dispatched to restore service.

[71] Gartner Inc. states: *"Information and technology are key enablers for utilities to achieve their mandates to provide ubiquitous economic and reliable services on demand. Core systems across the value chain are expected to achieve high levels of performance and availability. They also need to be modernized to support emerging requirements created by digital customer lifestyle, the growth of renewable energy, evolving markets, new entrants and ongoing regulatory developments."* See *Optimizing Foundational Technology in Utilities Primer for 2018*, January 9, 2018, page 2.

[72] Newfoundland Power's approach to electrical system automation is described in the Company's *2016/2017 General Rate Application (1st Revision), Volume 1, Application and Company Evidence, Section 3: Operations*, pages 3-22 to 3-24.

[73] Automated distribution feeders provide 2 primary benefits: (i) they can be controlled remotely by the System Control Centre, which mitigates the need to dispatch crews to energize or de-energize a distribution feeder; and (ii) they provide real-time visibility on the voltage and customer load on a feeder, which is used to manage peak load on the system and restore service to customers after a prolonged outage. In total, 240 of the Company's 306 distribution feeders were automated by year-end 2017.

distribution system doubled from 26 to 52 between 2013 and 2017.[74] Such automation allows the distribution system to be controlled remotely and provides greater flexibility in managing the Company's field crews. These benefits are particularly pronounced during significant events.[75]

2.4 OPERATING AND CAPITAL COSTS

2.4.1 Operating Costs

General

Gross operating costs represent approximately 9.6% of Newfoundland Power's proposed 2019 and 2020 revenue requirements from customer rates.[76] Gross operating costs are those costs over which Company management has the greatest degree of control.

Table 2-7 provides Newfoundland Power's gross operating costs for the period 2015 to 2020F.

Table 2-7:
Gross Operating Costs
2015 to 2020F
($000s)

2015	2016	2017	2018F	2019F	2020F
57,600	57,922	59,680	60,294	62,698	63,648

[74] Downline reclosers are pole-mounted devices that essentially divide a distribution feeder into multiple sections. The Company installs downline reclosers on distribution feeders to provide 2 primary benefits: (i) isolation of a fault so only a portion of customers on a feeder experience an outage, instead of all customers; and (ii) systematic restoration of power to customers after a prolonged outage.

[75] For example, during the severe wind storm that occurred in March 2017, the operation of 20 downline reclosers avoided over 1 million customer outage minutes without the assistance of field crews. Details of the Company's response during the storm were provided in the *March 2017 Wind Storm Report* filed with the Board on April 7, 2017.

[76] See *Volume 1, Application, Company Evidence and Exhibits, Exhibit 7*.

Gross operating costs are forecast to increase by approximately 10.5%, or $6.0 million, from 2015 to 2020. This represents an annual increase in operating costs of approximately 2.1%, or $1.2 million per year.

An examination of Newfoundland Power's gross operating costs by function and breakdown provides a greater understanding of these costs.

Classification by function focuses on the underlying reason for incurring a cost. Classification by breakdown focuses on the nature of a cost. For example, the Company classifies the salary of a Meter Reader in the Customer Relations department in 2 ways: (i) by function as a customer service cost; and (ii) by breakdown as a labour cost.

Volume 1, Application, Company Evidence and Exhibits, Exhibits 1 and 2, show the Company's gross operating costs from 2015 to 2020F by function and breakdown, respectively.

Operating Costs by Function

Table 2-8 summarizes Newfoundland Power's operating costs by 3 functional categories for the period 2015 to 2020F: (i) electricity supply; (ii) customer services; and (iii) general.

Table 2-8:
Operating Costs by Function
2015 to 2020F
($000s)

Function	**2015**	**2016**	**2017**	**2018F**	**2019F**	**2020F**
Electricity Supply	26,191	27,400	29,352	28,520	29,200	29,768
Customer Services	10,863	10,463	9,996	9,882	10,459	10,329
General	20,546	20,059	20,332	21,892	23,039	23,551
Total	**57,600**	**57,922**	**59,680**	**60,294**	**62,698**	**63,648**

Table 2-9 shows operating costs associated with the electricity supply category broken out by function for the period 2015 to 2020F.

Table 2-9:
Operating Costs – Electricity Supply
2015 to 2020F
($000s)

Function	**2015**	**2016**	**2017**	**2018F**	**2019F**	**2020F**
Distribution	8,903	9,369	10,748	9,876	10,077	10,274
Transmission	1,034	806	1,097	1,009	1,028	1,048
Substations	2,646	2,593	2,856	2,737	2,866	2,922
Power Produced	2,808	3,521	3,574	3,578	3,689	3,761
Administration & Engineering	7,375	7,727	7,660	7,826	7,980	8,137
Telecommunications	1,409	1,316	1,305	1,330	1,355	1,380
Environment	238	269	256	262	267	272
Fleet Operations & Maintenance	1,778	1,799	1,856	1,902	1,938	1,974
Total	**26,191**	**27,400**	**29,352**	**28,520**	**29,200**	**29,768**

Electricity supply costs for 2020 are forecast to increase by 13.7%, or approximately \$3.6 million, compared to 2015. This represents an annual increase in electricity supply costs of approximately 2.7%, or \$715,000 per year.

Increased distribution costs reflect higher labour costs required to complete system maintenance and to respond to significant events, such as the March 2017 wind storm.[77] Increased power produced costs reflect increases in the Provincial Government's water rental rate beginning in 2016.[78]

Table 2-10 provides costs associated with the customer services category broken out by function for the period 2015 to 2020F.

Table 2-10:
Operating Costs – Customer Services
2015 to 2020F
(\$000s)

Function	**2015**	**2016**	**2017**	**2018F**	**2019F**	**2020F**
Customer Service	8,843	8,830	7,990	7,841	8,189	8,164
Conservation	707	439	620	623	825	693
Uncollectible Bills	1,313	1,194	1,386	1,418	1,445	1,472
Total	**10,863**	**10,463**	**9,996**	**9,882**	**10,459**	**10,329**

[77] As an example, approximately \$641,000 in overtime labour was incurred in 2017 to respond to storm-related outages on the distribution system.

[78] The water rental rate charged by the Provincial Government for use of provincially owned water resources for hydroelectric generation is established by regulation. In 2016, the Provincial Government increased its water rental rate from \$0.80 to \$2.50 per MWh, with annual increases according to the Consumer Price Index. Approximately 56% of the increase in power produced costs between 2015 and 2020 is related to the higher water rental rate.

Customer services operating costs for 2020 are forecast to decrease by approximately 4.9%, or $534,000, compared to 2015. This represents an annual decrease in customer services costs of approximately 1.0%, or $107,000 per year.

The decrease in customer services costs includes a reduction in labour costs related to the accelerated deployment of AMR meters and a reduction in postage costs related to increased customer participation in ebills.[79] These cost savings are offset to a degree by: (i) increased temporary labour costs related to replacing the Company's Customer Service System; and (ii) increased uncollectible bills expense.[80]

Table 2-11 provides costs associated with the general category broken out by function for the period 2015 to 2020F.

Table 2-11:
Operating Costs – General
2015 to 2020F
($000s)

	2015	**2016**	**2017**	**2018F**	**2019F**	**2020F**
Information Systems	3,655	3,911	4,358	4,512	5,212	5,526
Financial Services	1,779	1,593	1,689	1,728	1,759	1,793
Corporate & Employee Services	13,852	13,262	12,959	14,295	14,686	14,824
Insurances	1,260	1,293	1,326	1,357	1,382	1,408
Total	**20,546**	**20,059**	**20,332**	**21,892**	**23,039**	**23,551**

79 The accelerated deployment of AMR meters and customer participation in ebills are described in *Section 2.2.2: Balancing Costs and Service*, pages 2-6 to 2-8, of this Application.

80 The replacement of the Company's Customer Service System is described in *Section 2.2.2: Balancing Costs and Service*, pages 2-10 to 2-12, of this Application. A review of the policies and practices affecting the Company's uncollectible bills expense is provided as part of the *2018 Rules and Regulations Review*, included in *Volume 2, Supporting Materials, Reports, Tab 8*.

General operating costs are forecast to increase by 14.6%, or approximately $3.0 million, from 2015 to 2020. This represents an annual increase in general costs of approximately 2.9%, or $601,000 per year.

Increased general operating costs include higher information systems costs, which are expected to increase by approximately $1.9 million over the 2015 to 2020 period. This includes approximately: (i) $992,000 for third-party software licensing and support;[81] (ii) $384,000 related to replacing the Company's Customer Service System; and (iii) $75,000 for a cybersecurity assessment.[82]

Corporate and employee services costs are expected to increase by $972,000 from 2015 to 2020. Increased costs over the forecast period reflect the increased number of regulatory proceedings associated with the commissioning of Nalcor Energy's Muskrat Falls project.[83]

81 The increase in third-party software licensing and support includes approximately: (i) $402,000 for operations and engineering software, such as the Company's SCADA System, Workforce Management System and new Outage Management System; (ii) $229,000 for customer service software, including the Company's website, Contact Management System, and outage alert software; (iii) $125,000 for cybersecurity software; and (iv) $236,000 for other software, including network, financial and human resources software.

82 Newfoundland Power implements a combination of cybersecurity initiatives to ensure the protection of customer and Company information. An assessment of Newfoundland Power's cybersecurity practices was completed in 2017. A follow-up assessment will be completed in 2020 to ensure the Company's cybersecurity practices continue to adapt to evolving risks.

83 Regulatory proceedings before the Board over the forecast period include: (i) Newfoundland Power's *2019/2020 General Rate Application;* (ii) Hydro's *2017 General Rate Application*; (iii) Hydro's cost of service methodology review beginning in late 2018; (iv) a Hydro general rate application in 2019/2020; and (v) the ongoing supply investigation related to interconnection with the Muskrat Falls project. In addition, the Muskrat Falls Inquiry is scheduled to begin in September 2018 and will include over 100 hearing days.

Operating Costs by Breakdown

The primary breakdown categories of Newfoundland Power's operating costs are labour costs and other costs (i.e. non-labour costs).

Table 2-12 provides the breakdown of operating costs for the period 2015 to 2020F.

Table 2-12:
Operating Costs by Breakdown
2015 to 2020F
($000s)

	2015	**2016**	**2017**	**2018F**	**2019F**	**2020F**
Labour	33,941	33,760	35,739	35,124	36,316	36,772
Other	23,659	24,162	23,941	25,170	26,382	26,876
Total	**57,600**	**57,922**	**59,680**	**60,294**	**62,698**	**63,648**

In 2020, other costs are forecast to account for approximately 42% of the Company's operating costs. Other costs include the goods and services the Company acquires from third parties to provide service to customers. These goods and services are typically acquired by competitive processes to ensure they are consistent with least-cost service delivery. Year-over-year variations in other costs typically reflect changes in Newfoundland Power's operating requirements. Examples include changes in operating requirements for software and computer equipment.

Other costs are forecast to increase by 13.6%, or approximately $3.2 million, from 2015 to 2020. This represents an annual increase of 2.7%, or approximately $643,000, through the period.

In 2020, labour costs are forecast to account for approximately 58% of the Company's operating costs. This is consistent with recent experience. Operating labour costs are an indicator of management efficiency in Newfoundland Power's day-to-day operations.

Newfoundland Power's labour costs are forecast to increase by 8.3%, or approximately $2.8 million, from 2015 to 2020. This represents an annual increase of 1.7%, or approximately $566,000, through the period.

Table 2-13 provides a breakdown of labour costs for the period 2015 to 2020F.

Table 2-13:
Labour Costs by Breakdown
2015 to 2020F
($000s)

	2015	**2016**	**2017**	**2018F**	**2019F**	**2020F**
Regular and Standby	29,700	29,329	30,539	30,463	31,131	31,525
Temporary	1,832	1,825	1,836	1,868	2,343	2,348
Overtime	2,409	2,606	3,364	2,793	2,842	2,899
Total	**33,941**	**33,760**	**35,739**	**35,124**	**36,316**	**36,772**

Regular and standby labour costs are forecast to increase by 6.1%, or approximately $1.8 million, from 2015 to 2020. This represents an annual increase of 1.2%, or approximately $365,000, through the period.

The increase in regular and standby labour reflects a combination of: (i) increased labour required to maintain the distribution system; (ii) annual labour inflation; and (iii) decreased labour costs associated with meter reading.

Temporary labour costs are forecast to increase by 28.2%, or approximately $516,000, from 2015 to 2020. This reflects: (i) increased temporary labour costs associated with the Company's Customer Service System; and (ii) annual labour inflation.

Overtime labour costs are forecast to increase by 20.3%, or approximately $490,000, from 2015 to 2020. This increase reflects normal labour inflation and an average of the amount of overtime required over the last 3 years.[84] Forecast overtime labour costs for 2019 and 2020 are lower than in 2017.

Overall, Newfoundland Power's operating labour costs for the period 2015 to 2020 show reasonable management efficiency.

Forecast operating costs related to the Company's 25-year-old Customer Service System are a once-in-a-generation expenditure. Excluding these costs, Newfoundland Power is forecasting an annual increase in labour costs of approximately 1.4% from 2015 to 2020.[85] The Company's weighted labour rate increase is forecast to average approximately 2.4% per year over the same period. This implies operating efficiency of approximately 1.0% per year.[86]

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[84] Overtime costs incurred in the last 3 years include events such as the March 2017 wind storm. It also includes increased overtime associated with routine response to trouble calls from customers.

[85] Total labour costs are forecast to be $36,772,000 in 2020. Of this, $408,000 relates to the Company's Customer Service System. Total labour costs excluding those costs are $36,364,000. (36,364,000 - 33,941,000) / 33,941,000 / 5 = 0.014, or 1.4%.

[86] Weighted labour rate increases reflect a combination of collectively bargained base wage increases agreed to between the Company and its union and forecast progression increases in employees' wages as a result of experience. For example, apprentice Powerline Technicians' wages increase by a combination of the base wage increase and the apprentice's progression through the apprenticeship program. The weighted labour rate increases are 3.54% in 2016, 3.13% in 2017, 1.75% in 2018 and 2019, and 2.00% in 2020. The 2.00% forecast increase in 2020 includes a 1.25% estimated base wage increase and a 0.75% forecast progression.

2.4.2 Capital Costs

Newfoundland Power targets stability and predictability in its annual capital budgeting. This approach is conducive to rate stability for customers and the maintenance of overall system performance.

Newfoundland Power's annual capital budget reflects expenditures necessary to maintain a large number of assets over a vast geographic area.

Table 2-14 provides capital expenditures by asset class for the period 2015 to 2020F.[87]

Table 2-14:
Capital Expenditures by Asset Class
2015 to 2020F
($000s)

	2015[88]	**2016[89]**	**2017[90]**	**2018F[91]**	**2019F**	**2020F**
Generation	5,205	18,512	6,402	8,420	12,091	7,737
Substations	22,515	14,402	16,227	12,788	13,891	17,089
Transmission	6,490	4,186	6,699	7,168	10,964	11,001
Distribution	47,884	44,652	46,299	38,857	38,355	41,030
General Property	3,295	3,509	1,456	1,763	2,397	2,454
Transportation	3,080	3,377	3,776	3,362	3,429	3,993
Telecommunications	78	331	112	198	102	104
Information Systems	7,578	9,106	4,314	6,570	6,973	6,394
Total	**96,125**	**98,075**	**85,285**	**79,126**	**88,202**	**89,802**

87 These expenditures do not include the allowance for unforeseen or general expenses capitalized ("GEC"). Capital expenditures for 2015 to 2017 include expenditures related to approved projects that were completed in subsequent years. Forecast capital expenditures reflect the Company's *2018 Capital Plan*.

88 The Company's *2015 Capital Budget Application* was approved in Order No. P.U. 040 (2014).

89 The Company's *2016 Capital Budget Application* was approved in Order No. P.U. 028 (2015).

90 The Company's *2017 Capital Budget Application* was approved in Order No. P.U. 039 (2016).

91 The Company's *2018 Capital Budget Application* was approved in Order No. P.U. 037 (2017).

From 2015 to 2017, Newfoundland Power's capital expenditures across all asset classes averaged approximately $93 million per year. From 2018 to 2020, capital expenditures are forecast to average approximately $86 million per year.

The reduction in capital expenditures over the forecast period reflects a decrease in customer requirements and completion of the deployment of AMR meters. This decrease is primarily observed in the Distribution category. From 2015 to 2017, Distribution capital expenditures averaged approximately $46 million per year. From 2018 to 2020, Distribution capital expenditures are forecast to average approximately $39 million per year.

Newfoundland Power's annual capital programming continues to focus on the replacement and refurbishment of existing assets. More than ½ of the Company's capital expenditures over the forecast period relate to the replacement or refurbishment of existing assets.

SECTION 3: FINANCE

3.1 OVERVIEW

The maintenance of Newfoundland Power's financial integrity is critical to the Company's long-term ability to deliver safe, reliable electrical service to its customers at least cost. For this reason, diligent financial management benefits both the Company and its customers.

Newfoundland Power's financial management has enabled the Company to maintain its financial integrity over time. Forecast financial results, excluding the proposals in this Application, are not expected to maintain the financial integrity of the Company in 2019 and 2020. Results are also not expected to be consistent with the fair return standard.

The Company's cost of capital is a key issue in this Application. Expert evidence filed with this Application indicates a fair return for Newfoundland Power for 2019 and 2020 comprises: (i) a capital structure consisting of 45% common equity, and (ii) a return on equity of 9.5%. Combined, a 45% common equity component and a 9.5% rate of return on equity is consistent with the maintenance of Newfoundland Power's financial integrity and the fair return standard.

In this Application, Newfoundland Power proposes continued suspension of the Automatic Adjustment Formula for determining the Company's rate of return on equity between test years.

Newfoundland Power is proposing a change in how the Company accounts for pension costs. This reflects recent changes in accounting standards.

The Company is proposing to amortize up to $1 million in Board and Consumer Advocate costs in relation to this Application over a 34-month period ending in December 2021. Costs in excess of $1 million are proposed to be recovered through the Company's Rate Stabilization Account. The Company also proposes to amortize a 2019 revenue surplus of $919,000 over a 34-month period ending in December 2021.

3.2 FINANCIAL PERFORMANCE: 2015 TO 2020

Newfoundland Power manages its financial performance over the long and short term to ensure continued financial integrity. The Company's financial integrity up to 2018 is reflective of this stable and consistent approach to financial management. Excluding the proposals made in this Application, Newfoundland Power's financial integrity deteriorates over the 2019 to 2020 period.

Exhibit 3 in Volume 1, Application, Company Evidence and Exhibits, details Newfoundland Power's actual financial performance for 2015 to 2017. Exhibit 3 also shows forecast financial performance for 2018 to 2020, excluding the proposals in this Application.

Exhibit 5 in Volume 1, Application, Company Evidence and Exhibits, compares forecast financial performance for 2019 and 2020 based on existing customer rates and proposed rates which incorporate the proposals in this Application.

3.2.1 Revenue

Energy Sales and Electricity Revenue

Table 3-1 shows energy sales and electricity revenue for the period 2015 to 2020E, excluding the proposals in this Application.[1]

Table 3-1:
Energy Sales and Electricity Revenue[2]
2015 to 2020E

	2015	2016	2017	2018F	2019E	2020E
Energy Sales						
Energy Sales (GWh)	5,957	5,950	5,922	5,915	5,889	5,899
Sales Growth (%)	1.0	-0.1	-0.5	-0.1	-0.4	0.2
Electricity Revenue ($000s)						
Revenue from Rates	639,631	661,449[3]	661,884	658,466	655,841	657,459
RSA Transfers	7,414	4,856	3,797	(1,663)	(6,337)	(6,743)
Total Electricity Revenue	**647,045**	**666,305**	**665,681**	**656,803**	**649,504**	**650,716**

In 2016 and 2017, Newfoundland Power experienced declines in energy sales of 0.1% and 0.5%, respectively. Sales are forecast to decrease by 0.1% in 2018 and 0.4% in 2019. Sales are

1 References to 2019 and 2020 with the suffix 'E' (e.g. 2019E) reflect forecast results under the Company's existing scenario and exclude the proposals in this Application. The suffix 'P' reflects forecast results that include the proposals in this Application.

2 Forecast energy sales and electricity revenue for 2018 to 2020E are based on the Company's April 2018 sales forecast. The April 2018 *Customer, Energy and Demand Forecast* is found in *Volume 2, Supporting Materials, Reports, Tab 3.*

3 In 2013, Newfoundland Power recorded excess earnings of $68,000. This amount was applied to the Company's 2016 revenue requirement as proposed in the Company's *2016/2017 General Rate Application*. This effectively reduced the amount of revenue recovered from customer rates in 2016 by $68,000.

expected to increase by 0.2% in 2020. However, without the additional day provided by a leap year, sales would be expected to decline by 0.1% in 2020.[4]

Other Revenue

Table 3-2 shows other revenue for the period 2015 to 2020E.

Table 3-2:
Other Revenue
2015 to 2020E
($000s)

	2015	**2016**	**2017**	**2018F**	**2019E**	**2020E**
Pole Attachment	1,744	1,902	2,429	2,299	2,318	2,360
Provisioning Work	707	737	931	1,227	943	883
Customer Account Interest	977	923	888	929	913	909
Interest on RSA	63	281	615	373	(28)	(219)
Wheeling Charges	654	699	714	745	751	758
Miscellaneous	1,061	692	706	807	687	684
Total	**5,206**	**5,234**	**6,283**	**6,380**	**5,584**	**5,375**

The Company's other revenue forecast for 2019 and 2020 is comparable to 2015 and 2016.

Other revenue in 2017 and 2018 is approximately $1 million higher than 2015 and 2016. This is due to higher pole attachment rates charged to cable TV operators, increased provisioning work, and higher interest on the Company's Rate Stabilization Account ("RSA") balance.[5]

4 Electricity sales are forecast to be 5,899 GWh in 2020. Excluding the additional day provided by a leap year, electricity sales in 2020 would be 5,883 GWh or 0.1% lower than in 2019 ((5,883 – 5,889) / 5,889 = -0.001, or -0.1%).

5 Increased pole attachment and provisioning revenue in 2017 and 2018 is attributable to network upgrade initiatives undertaken by telecommunications providers.

Other revenue is forecast to decline in 2019 and 2020 primarily due to lower interest on the Company's RSA.

3.2.2 Power Supply

Table 3-3 shows power supply costs for the period 2015 to 2020E.

Table 3-3:
Power Supply Costs
2015 to 2020E
($000s)

	2015	**2016**	**2017**	**2018F**	**2019E**	**2020E**
Purchases from Hydro (Normalized)	424,430	443,311	435,306	432,443	430,627	430,644
Weather Normalization Reserve	(2,335)	-	-	-	-	-
Demand Management Incentive Account	-	-	(2,128)	-	-	-
Wholesale Rate Change Flow-Through	-	-	7,071	-	-	-
Power Supply Costs	**422,095**	**443,311**	**440,249**	**432,443**	**430,627**	**430,644**

Power supply costs are expected to increase by approximately $8.5 million from 2015 to 2020. This is largely attributable to an increase in Hydro's Utility Rate, partially offset by declining energy sales.[6]

[6] See Order No. P.U. 23 (2017).

3.2.3 Depreciation

Table 3-4 shows depreciation expense for the period 2015 to 2020E.

Table 3-4:
Depreciation Expense
2015 to 2020E
($000s)

	2015	2016	2017	2018F	2019E	2020E
Depreciation	51,851	55,190	57,487	59,801	62,314	64,797

Increases in annual depreciation expense over the period 2015 to 2020 are substantially the result of the Company's annual capital investment in the electrical system.

Newfoundland Power's depreciation expense reflects the methodology and depreciation rates outlined in its *2014 Depreciation Study*.[7] The depreciation study and depreciation expense formed part of the settlement agreement established during the *2016/2017 General Rate Application* and was approved by the Board.[8]

Newfoundland Power's depreciation rates are typically reviewed every 4 to 5 years.[9] The next depreciation study is expected to be completed in 2020 based on plant in service as of December 31, 2019.

[7] In Order No. P.U.13 (2013), the Board ordered Newfoundland Power to file its next depreciation study, relating to plant in service as of December 31, 2014, with its next general rate application. Gannett Fleming Valuation and Rate Consultants, LLC performed the depreciation study as required by the Board. The *2014 Depreciation Study* was filed in *Volume 3, Expert Evidence & Studies, Tab 2*, as a part of the Company's *2016/2017 General Rate Application*.

[8] See Order No. P.U. 18 (2016), page 7, lines 5-30. The approved depreciation rates stemming from the *2014 Depreciation Study* became effective January 1, 2016.

[9] The Company's previous 4 depreciation studies were completed for plant in service at December 31, 2001, 2005, 2010 and 2014.

3.2.4 Employee Future Benefits

General

Newfoundland Power maintains plans for its employees that provide benefits upon retirement. These plans fall into 2 broad categories: pension plans and other post-employment benefits ("OPEB") plans.

Table 3-5 shows employee future benefits expense for the period 2015 to 2020E.

Table 3-5:
Employee Future Benefits Expense
2015 to 2020E
($000s)

	2015	**2016**	**2017**	**2018F**	**2019E**	**2020E**
Pension Expense	17,702	9,763	8,675	7,835	2,882	1,263
OPEB Expense	8,653	8,678	8,364	6,194	6,198	6,303
Total Expense	**26,355**	**18,441**	**17,039**	**14,029**	**9,080**	**7,566**

Newfoundland Power expects total employee future benefits expense to decrease by approximately $18.8 million from 2015 to 2020.

Pensions

Newfoundland Power maintains both defined benefit and defined contribution pension plans.[10]

[10] Newfoundland Power's largest pension plan is its defined benefit pension plan which was created in 1984. There were 237 active employees participating in this plan as at December 31, 2017. In addition, at December 31, 2017, the defined benefit pension plan provided retirement income to a total of 761 retirees and their survivors. The defined benefit pension plan provides retirement income based upon an employee's pay and years of service at the time of retirement.

The Company's defined benefit pension plan has been closed to new entrants for approximately 14 years. Employees hired since that time participate in a defined contribution pension plan, which provides retirement income based upon the contributions made by the Company and employee, together with the accrued returns on those contributions.

Table 3-6 shows the components of Newfoundland Power's pension expense for the period 2015 to 2020E.

Table 3-6:
Pension Expense
2015 to 2020E
($000s)

	2015	**2016**	**2017**	**2018F**	**2019E**	**2020E**
Defined Contribution Pension Plans	1,805	1,881	1,961	2,172	2,532	2,725
Defined Benefit Pension Plans	15,897	7,882	6,714	5,663	350	(1,462)
Total Pension Expense	**17,702**	**9,763**	**8,675**	**7,835**	**2,882**	**1,263**

Increased defined contribution pension plans expense of approximately $920,000 from 2015 to 2020 reflects increased enrolment and increases in compensation.

Defined benefit pension plans expense is forecast to decrease by approximately $17.4 million between 2015 and 2020. The decline is influenced by a combination of factors including: (i) increases in plan assets due to increased solvency payments to 2015;[11] (ii) returns on plan

[11] The defined benefit pension plan valuations, dated December 31, 2011 and December 31, 2014, identified the need for special solvency payments (inclusive of interest) for 2012, 2013, 2014 and 2015. Payments of $10.7 million were required annually for 2012, 2013, and 2014. A payment of $7.0 million was required for 2015.

assets to 2017;[12] (iii) the expiry of regulatory amortizations in 2017;[13] (iv) a stable forecast discount rate;[14] and (v) the results of the Company's defined benefit pension plan valuation, dated December 31, 2017.[15]

OPEB

Table 3-7 shows OPEB expense for the period 2015 to 2020E.

Table 3-7:
OPEB
2015 to 2020E
($000s)

	2015	2016	2017	2018F	2019E	2020E
OPEB Expense	8,653	8,678	8,364	6,194	6,198	6,303

OPEB expense is forecast to decrease by approximately $2.4 million between 2015 and 2020. This reflects: (i) the expiry of a regulatory amortization; and (ii) a reduction in claims cost experience with the Company's OPEB plan.[16]

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12 In 2017, the return on defined benefit pension plan assets was 8.9%. For the previous 5 years (2012 to 2016), returns were, 7.6%, 8.7%, 15.5%, 3.6% and 7.8%.

13 Transitional obligations associated with the Company's defined benefit pension plans were amortized through 2017 as an increase to employee future benefits expense of $1.3 million on an annual basis. These amortizations concluded in 2017.

14 A discount rate of 3.6% is forecast for 2018, 2019 and 2020.

15 The Company completes an actuarial pension valuation every 3 years. The latest valuation was completed as at December 31, 2017. There were a number of results in the valuation that contributed to a lower forecast pension expense for 2019 and 2020. The number of active members in the plan has decreased from 328 as at December 31, 2014, to 237 as at December 31, 2017. Lower active members results in less current service cost to be expensed. A calculated actuarial gain of $8.5 million as a result of the valuation will reduce pension expense in 2019 and 2020. The gain primarily reflects updated membership data, such as lower annual compensation rates. Finally, the expected average remaining service life of employees participating in the plan was increased from 7.04 years to 7.44 years for 2019, and from 6.55 years to 6.96 years for 2020. An increased expected average remaining service life of employees increases the expected period of contribution of employees to the pension plan and increases the period over which actuarial gains and losses in the plan are amortized. No solvency payments are required as a result of the December 31, 2017 pension valuation.

16 A transitional obligation associated with the Company's OPEB plan was amortized through 2017 as an increase to employee future benefits expense of $1.4 million annually. The amortization concluded in 2017.

3.2.5 Finance Charges

Table 3-8 shows average debt, finance charges and average cost of debt for the period 2015 to 2020E.[17]

Table 3-8:
Finance Charges
2015 to 2020E

	2015	2016	2017	2018F	2019E	2020E
Average Debt ($000s)	559,350	572,841	586,726	609,381	623,801	637,582
Finance Charges ($000s)	35,161	34,643	34,894	35,768	35,948	37,034
Average Cost of Debt (%)	6.29	6.05	5.95	5.87	5.76	5.81

Newfoundland Power's average debt is expected to increase by approximately $78 million from 2015 to 2020. This increase is primarily to finance capital expenditures necessary to maintain system reliability and to respond to customer requirements.[18] During the same period, finance charges are expected to increase by approximately $1.9 million.

The Company's average cost of debt from 2015 to 2020 is expected to decline by 0.48%. This primarily reflects lower average coupon rates on the Company's first mortgage bonds.[19]

[17] Table 3-8 shows regulated finance charges, which exclude interest on security deposits as they are not included in the determination of revenue requirements.

[18] Newfoundland Power's annual capital budgets for the period 2015 through 2018 were approved by the Board in Order Nos. P.U. 40 (2014), P.U. 28 (2015), P.U. 39 (2016), and P.U. 37 (2017). Approximately 54% of the Company's approved *2018 Capital Budget Application* is related to the replacement of plant. A further 21% is related to serving new customers and to address system capacity constraints in areas experiencing load growth.

[19] This is a result of higher interest rate debt being retired and replaced with lower interest rate debt. For example, in 2016 Newfoundland Power repaid $30.4 million associated with the maturity of 10.9% Series AE First Mortgage Bonds. In 2017, the Company issued its $75 million Series AP First Mortgage Bonds which had a coupon rate of 3.815%.

3.2.6 Income Taxes

Table 3-9 shows income taxes for the period 2015 to 2020E.

Table 3-9:
Income Taxes
2015 to 2020E

	2015	2016	2017	2018F	2019E	2020E
Income Taxes ($000s)	16,529	18,152	19,424	18,137	15,814	14,985
Effective Income Tax Rate (%)	28.68	29.74	30.63	29.95	30.16	30.29

Newfoundland Power's effective income tax rate increased from approximately 29% in 2015 to approximately 30% over the 2016 to 2020 period. This is reflective of the 1% increase in the statutory corporate income tax rate in 2016.[20]

3.2.7 Returns

Table 3-10 shows the approved rates of return on rate base, the actual and forecast rates of return on rate base, and the actual and forecast rates of return on common equity for the period 2015 to 2020E.

Table 3-10:
Rates of Return
2015 to 2020E
(%)

	2015	2016	2017	2018F	2019E	2020E
Return on Rate Base						
Midpoint (Approved)	7.50	7.21	7.19	7.04	-	-
Actual / Forecast	7.48	7.31	7.22	7.00	6.34	6.09
Return on Common Equity	8.98	8.90	8.93	8.47	7.04	6.44

[20] Effective January 1, 2016, the Newfoundland and Labrador portion of the general corporate income tax rate was increased from 14% to 15%. The federal corporate income tax rate is 15%.

Newfoundland Power's rate of return on rate base was within the range approved by the Board for 2015, 2016, and 2017.[21] In 2018, the Company is forecasting a return on rate base slightly below the midpoint approved by the Board.[22]

The forecast rate of return on rate base and rate of return on equity for 2019 and 2020 reflects the eroding financial position of the Company over the period.

3.2.8 Credit Metrics

Table 3-11 shows Newfoundland Power's credit metrics for the period 2015 to 2020E.

Table 3-11:
Credit Metrics
2015 to 2020E

	2015	2016	2017	2018F	2019E	2020E
Pre-tax Interest Coverage (times)	2.3	2.4	2.5	2.4	2.2	2.0
Cash Flow Interest Coverage (times)	3.8	4.0	4.0	4.0	3.7	3.7
Cash Flow Debt Coverage (%)	17.5	18.0	17.8	17.3	15.8	15.4

Newfoundland Power maintains an investment grade credit rating from 2 independent rating agencies: DBRS Limited ("DBRS") and Moody's Investor Services ("Moody's").[23] A review of

[21] In Order No. P.U. 51 (2014), the Board approved a rate of return on rate base for 2015 of 7.50% in a range of 7.32% to 7.68%. In Order No. P.U. 25 (2016), the Board approved a return on rate base for 2016 of 7.21% in a range of 7.03% to 7.39%, and the rate of return on rate base for 2017 of 7.19% in a range of 7.01% to 7.37%.

[22] In Order No. P.U. 41 (2017), the Board approved a rate of return on rate base for 2018 of 7.04% in a range of 6.86% to 7.22%.

[23] The most recent DBRS and Moody's credit rating reports are filed in *Volume 1, Application, Company Evidence and Exhibits, Exhibit 4.* DBRS has consistently rated both Newfoundland Power and its first mortgage bonds with an 'A' credit rating. Moody's Long Term Rating for Newfoundland Power is 'Baa1'.

the Company's credit metrics forms a part of the DBRS and Moody's annual credit rating assessments.[24]

From 2017 to 2018, the Company's credit metrics are expected to remain stable. This stability is consistent with the expectations of DBRS and is considered a credit strength by Moody's.[25]

Newfoundland Power's credit metrics and financial outlook are expected to decline in 2019 and 2020. This, combined with Newfoundland Power's business risk, can affect the Company's ability to maintain current credit ratings and access capital markets at reasonable costs.

3.3 COST OF CAPITAL

In this Application the Board will consider Newfoundland Power's cost of capital for 2019 and 2020. The Board will also consider whether financial markets support the use of an automatic adjustment formula to annually adjust the return on rate base to reflect changes in the cost of equity for years following 2019 and 2020.

The expert evidence filed with this Application indicates a fair return for Newfoundland Power for 2019 and 2020 comprises: (i) a capital structure consisting of 45% common equity, and (ii) a return on equity of 9.5%. The expert evidence also recommends continued suspension of the Automatic Adjustment Formula.

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[24] Moody's uses a 4-factor scorecard in its determination of an appropriate credit rating for regulated electric and gas utilities. The scorecard assigns 40% weighting to *Financial Strength* which includes an assessment of credit metrics. The remaining 60% applies to *Regulatory Framework* (25%), *Ability to Recover Costs and Earn Returns* (25%), and *Diversification* (10%).

[25] In its September 5, 2017 rating report, DBRS stated: *"Going forward, DBRS expects key credit metrics to remain in line with the current rating category"* (page 1). In its January 31, 2018 credit opinion, Moody's stated that *"stable cash flow metrics"* were a credit strength (page 2).

The Board typically reviews Newfoundland Power's cost of capital approximately once every 3 years. In determining a fair return, the Board has consistently applied principles prescribed by the Electrical Power Control Act, 1994, the Public Utilities Act, and the fair return standard. The Board's historical interpretation of a fair return is one that is: (i) commensurate with return on investments of similar risk; (ii) sufficient to ensure financial integrity; and (iii) sufficient to attract necessary capital.

This section of evidence outlines the findings of the Board's comprehensive review of the Company's capital structure in 2016. A 2018 assessment of the factors affecting the Company's business risk shows that, since the Board's 2016 review, the Company's business risk has become more pronounced.

This section of the evidence also reviews Newfoundland Power's credit metrics under the Company's existing scenario and with the proposals in this Application. The proposals in this Application, which include a return on equity of 9.5% based on a capital structure with a target equity ratio of 45%, are consistent with the fair return standard.

The use of the Automatic Adjustment Formula has been suspended since 2012 due to low long Canada bond yields. Newfoundland Power observes that current yields are comparable to yields in 2012 and 2016 and therefore proposes the continued suspension of the Formula.

3.3.1 Regulatory Framework

Background

Newfoundland Power is required to invest capital into the electrical system to ensure the continued delivery of reliable service to customers. Each year, the Company's forecast capital expenditures for the ensuing year are considered and approved by the Board. The source of this capital investment is a combination of common equity and debt financing.[26] The Company's cost of capital depends on: (i) the amount of common equity and debt used to finance capital investment; (ii) the rate of return on common equity; and (iii) the interest rates on the outstanding debt.

The Board determines the proportion of equity that can be used in Newfoundland Power's capital structure for ratemaking purposes. The Board also determines the Company's rate of return on equity used to establish customer rates.

Interest rates on the Company's debt are determined by financial markets. Interest on short-term debt is primarily based upon prime lending rates. Interest on long-term debt is determined by capital markets at the time the debt is issued. Debt rating agencies, such as Moody's and DBRS, facilitate financial markets by providing credit ratings that are indicative of the risk of the investment.[27] Newfoundland Power as a debt issuer, and its long-term debt, have held

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[26] Newfoundland Power has both short-term and long-term debt. Short-term debt consists of a $100 million committed revolving term facility and a $20 million demand facility. The Company's long-term debt primarily consists of first mortgage bonds.

[27] Moody's Baseline Credit Assessments ("BCA") reflect Moody's opinions of issuers' standalone intrinsic strength, absent any extraordinary support from an affiliate or a government. BCA is measured on a 9-step scale from 'c' to 'aaa.' Newfoundland Power is currently rated baa1. Moody's states *"Issuers assessed baa are judged to have medium-grade intrinsic, or standalone, financial strength, and thus subject to moderate credit risk and, as such, may possess certain speculative credit elements absent any possibility of extraordinary support from an affiliate or a government."*

investment grade ratings from 2 credit rating agencies for over 2 decades. The Company's capital structure and rate of return on equity are measures of financial risk considered by credit rating agencies in determining an appropriate credit rating for Newfoundland Power.[28] Capital structure, rate of return on equity, and credit ratings are therefore interrelated.

Legislative Context

Newfoundland Power is regulated under provincial legislation, which includes: (i) the *Electrical Power Control Act*, *1994* (the "EPCA"); and (ii) the *Public Utilities Act* (the "Act"). The legislative construct for Newfoundland Power is broadly consistent with those of other investor-owned utilities in Canada.

The EPCA establishes the power policy of Newfoundland and Labrador. Section 3(a)(iii) states:

> *"It is declared to be the policy of the province that…the rates to be charged, either generally or under specific contracts, for the supply of power within the province…should provide sufficient revenue to the producer or retailer of the power to enable it to earn a just and reasonable return as construed under the Public Utilities Act so that it is able to achieve and maintain a sound credit rating in the financial markets of the world."*

The Act establishes the legislative powers of the Board. Section 80 states:

> *"(1) A public utility is entitled to earn annually a just and reasonable return as determined by the board on the rate base as fixed and determined by the board…"*
>
> *"(2) The return shall be in addition to those expenses that the board may allow as reasonable and prudent and properly chargeable to operating account, and to all just allowances made by the board according to this Act and the rules and regulations of the board."*

[28] Credit rating agencies also evaluate the risks inherent in the Company's operations, known as "business risks."

The Fair Return Standard

In determining an appropriate capital structure and return on equity for Newfoundland Power, the Board is guided by the fair return standard. In Order No. P.U. 32 (2007), the Board described the fair return standard as follows:

> *"Regulated utilities are given the opportunity to earn a fair rate of return. To be considered fair, the return must be:*
> - *Commensurate with return on investments of similar risk;*
> - *Sufficient to ensure financial integrity; and*
> - *Sufficient to attract necessary capital.*
>
> *The fair return principle is consistent with both Section 80(1) of the Act and Section 3(a)(iii) of the EPCA."*[29]

The Board has applied its view of the fair return standard for Newfoundland Power in a number of proceedings. In Order No. P.U. 18 (2016), the Board stated:

> *"In Order No. P.U. 43(2009) and in Order No. P.U. 13(2013), its most recent Order on this issue, the Board stated that "to be considered fair the return must be commensurate with the return on investments of similar risk and sufficient to assure financial integrity and to attract necessary capital. This statement, which reflects accepted regulatory principles, concisely captures the requirements that must be met to determine a fair return. All three requirements must be met and no one requirement takes precedence over the other two."*[30]

The Board's view of the fair return standard is one that is commonly accepted throughout North America.

Capital Structure

Newfoundland Power's targeted capital structure consists of 45% common equity for ratemaking purposes. It has not changed in over 2 decades and has contributed to the Company's continued access to capital markets at reasonable rates.

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29 See Order No. P.U. 32 (2007), Appendix A, page 6.
30 See Order No. P.U. 18 (2016), page 10, line 44 to page 11, line 4.

The Board has acknowledged that a fair return cannot be determined independently of a utility's capital structure.[31]

The significance of capital structure in determining a fair return has also been recognized by the Newfoundland and Labrador Court of Appeal:

> *"[134]…the level of overall capitalization and the composition of the capital structure of a utility are both matters of regulatory concern, at least insofar as they affect the utility's rate of return on rate base and hence the cost to consumers of the delivery of reliable service…*
>
> *[135] In approaching these questions, it has to be remembered that there is no such thing as one ideal capital structure. It is a function of economic conditions, business risks and 'largely a matter of business judgment'. Furthermore, a given capital structure cannot be changed easily or quickly. As well, the long-term effects of changes on capital structure on the enterprise and on the future cost of capital may not be easily predictable."*[32]

The Board's views of the appropriateness of Newfoundland Power's longstanding capital structure have remained consistent since it was first approved in 1996. In Order No. P.U. 19 (2003), the Board stated:

> *"The capital structure of NP has been maintained through the ongoing decisions of the Board as contained in its respective Orders and also NP's actions in managing the level of common equity accordingly. Generally in the past it has been determined by the Board that a strong equity component is needed to mitigate the impact of NP's relatively small size and low growth potential."*[33]

Newfoundland Power's capital structure formed a part of settlement agreements in the Company's 2008 and 2010 general rate applications.[34]

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[31] See Order No. P.U. 18 (2016), page 11, lines 4-5.
[32] See *The Stated Case*, June 15, 1998, Newfoundland and Labrador Court of Appeal, paragraphs 134-135.
[33] See Order No. P.U. 19 (2003), page 45.
[34] See Order Nos. P.U. 32 (2007) and P.U. 43 (2009).

In Order No. P.U. 13 (2013), following a review of Newfoundland Power's capital structure in the Company's *2013/2014 General Rate Application*, the Board stated:

> *"Newfoundland Power has had a deemed common equity ratio of approximately 45% for the last twenty five years and the evidence is clear that the rating agencies place importance on its strong common equity position. There is no evidence of a change in circumstances which would justify a change in the ratio and there is little substantive evidence demonstrating that the appropriate common equity ratio for Newfoundland Power is 40%. The Board therefore finds that a change in the common equity ratio has not been justified in the circumstances."*[35]

The Board also stated in its Order that Newfoundland Power's capital structure should be comprehensively reviewed as part of the Company's next general rate application.

The Board's 2016 Capital Structure Review

Newfoundland Power's capital structure was comprehensively reviewed in the Company's *2016/2017 General Rate Application*, which concluded approximately 2 years ago.[36] The Board's review involved an assessment of factors affecting the Company's business risk. These included increased power supply costs resulting from the Muskrat Falls project, the provincial economic outlook, and Newfoundland Power's small size in relation to its peers and low growth potential. The Board also considered the views of the Company's credit rating agencies.

In its assessment of Newfoundland Power's risk and capital structure, the Board concluded that it was not appropriate to deem a reduced common equity ratio for Newfoundland Power given the uncertainty associated with the Muskrat Falls project and the economic outlook for the province. The Board also expressed concern about the impact a reduced common equity ratio would have

[35] See Order No. P.U. 13 (2013), page 17, lines 8-13.
[36] See Order No. P.U. 18 (2016).

on Newfoundland Power's credit metrics and how it would be viewed by the Company's credit rating agencies.[37] The Board concluded that the circumstances required a conservative and stable regulatory approach and continuation of Newfoundland Power's longstanding capital structure.

3.3.2 2018 Risk Assessment

General

Since 2016, certain factors affecting the Company's business risk have become more pronounced. The provincial economic outlook has deteriorated, energy sales have begun to decline, and the projected costs relating to the Muskrat Falls project have increased. Other factors, such as the Company's small size, service territory demographics, operating environment, regulatory mechanisms, and limited cost flexibility, continue to define Newfoundland Power's business risk.

Provincial Economy

The economics of Newfoundland Power's service territory are expected to remain weak compared to the rest of Canada. The Conference Board of Canada recognizes the challenges facing the province and forecasts slow overall economic growth throughout the 2018 to 2040 period:

> *"The depletion of oil reserves and the aging population will severely slow overall economic growth in Newfoundland and Labrador over the forecast period, leaving it with the lowest average annual growth rate of any province for the 2018-40 period. Average annual growth over the long term in Newfoundland and Labrador will be two percentage points below that of the fastest-growing*

[37] See Order No. P.U. 18 (2016), page 24, lines 32-38.

provinces of Alberta and Ontario. And while that might not seem like a lot, it becomes huge when compounded over more than two and a half decades."[38]

A slowing economy is also reflected in the forecast employment outlook for the province.

Table 3-12 provides a comparison of the Conference Board of Canada's 2016 employment outlook compared to what it most recently published in 2018.

Table 3-12:
Employment Outlook (000s)
2018 to 2022

Employment	**2018**	**2019**	**2020**	**2021**	**2022**
2018 Outlook[39]	219	218	215	213	212
2016 Outlook[40]	233	233	231	230	231
Difference	(14)	(15)	(16)	(17)	(19)

The 2018 employment outlook is more negative than the 2016 outlook. In comparison to 2016, the Conference Board of Canada's latest outlook is forecasting 14,000 fewer people employed in the province in 2018 and 19,000 fewer people employed in 2022.

The weak economic conditions forecast for Newfoundland and Labrador present risks to the Company's ability to recover its investment in long-life utility assets and earn a fair return.

38 Conference Board of Canada, *Provincial Outlook 2018, Long Term Forecast*, January 19, 2018, page v.
39 Conference Board of Canada, *Provincial Outlook 2018, Long Term Forecast*, January 19, 2018.
40 Conference Board of Canada, *Provincial Outlook 2016, Long-Term Forecast*, December 11, 2015.

Service Territory Demographics

The population of Newfoundland and Labrador is projected to decline throughout the 2018 to 2040 period. This is due to a falling natural rate of increase, persistent out-migration, and a rising average age. The province's population peaked in 2017 at 531,130 and is expected to decrease by approximately 11% to 472,043 by 2040.[41] This compares to a 19% increase in the Canadian population over the same time horizon.[42]

In addition to a declining population, the province's population is older than the Canadian population. The median age of the Newfoundland and Labrador population is approximately 5 years higher than the median age of the Canadian population.[43]

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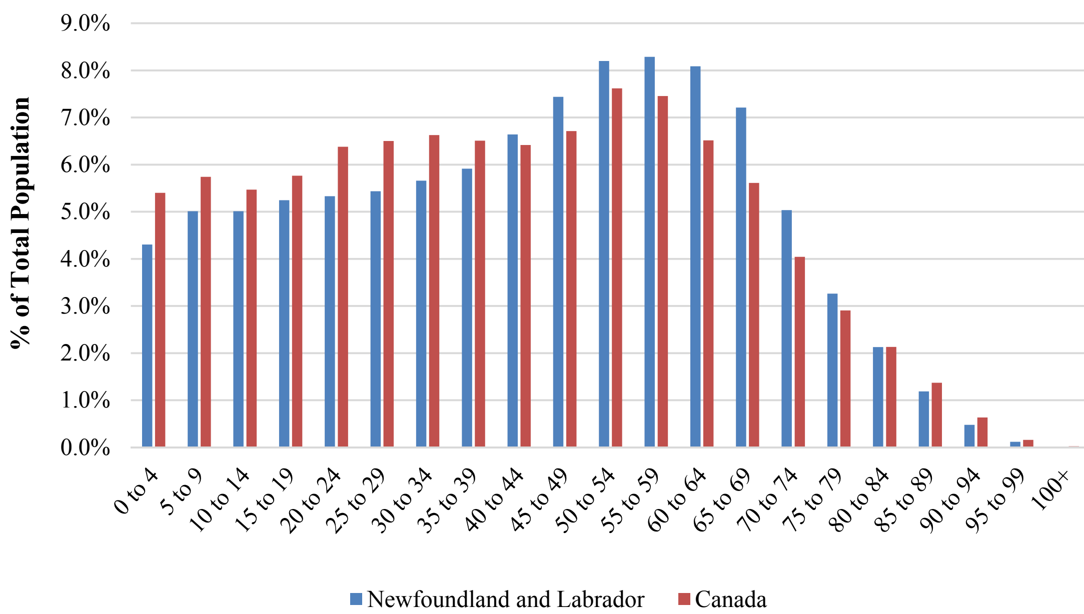
[41] See *Volume 2, Supporting Materials, Reports, Tab 3: Customer, Energy, and Demand Forecast*, Attachment A, page 3.

[42] The Canadian population is forecast to grow from 36,639,000 in 2017 to 43,632,000 in 2040, an increase of approximately 19.1%. See *Table 1a Key Economic Indicators: Canada, 2014-27* and *Table 1b Key Economic Indicators: Canada, 2028-40* of the Conference Board of Canada, *Provincial Outlook 2018, Long-Term Economic Forecast,* January 19, 2018.

[43] The median age of the Newfoundland and Labrador population is 46.0 years. The median age of the Canadian Population is 41.2 years. See Statistics Canada Catalogue no. 98-316-X2016001, released November 29, 2017.

Figure 3-1 shows the population by age cohorts for Newfoundland and Labrador compared to Canada.

Figure 3-1:
Newfoundland and Labrador vs Canada
Population by Age Cohorts
(2016)



Younger cohorts, up to age 39, represent a larger proportion of the Canadian population than the Newfoundland and Labrador population. Older cohorts, over age 40, represent a larger proportion of Newfoundland and Labrador's population.[44]

The demographic changes forecast for Newfoundland and Labrador are expected to have a negative influence on the provincial economy. In its 2018 *Provincial Outlook, Long-Term*

44 Statistics Canada Catalogue no. 98-316-X2016001, released November 29, 2017.

Economic Forecast, the Conference Board of Canada states:

> *"The profound demographic changes will slow down the provincial economy over the forecast period. Economic growth is projected to decelerate from an annual average of 1.9 percent over 2001-15 to an average of 1.0 per cent between 2016 and 2020. Growth would be even weaker were it not for the Hebron offshore oil project, where production came online at the end of 2017. Economic growth will stall during the final two decades of the forecast. Real GDP is expected to contract by an average of 0.2 percent a year over 2021-40 as demographic changes erode the gains from potential resource development."*[45]

In addition to a declining and aging population, the population of the island portion of the province is becoming more concentrated on the North East Avalon and less concentrated in rural areas.[46] From 2016 to 2036, the population of the North East Avalon is expected to increase by approximately 15%, whereas the population of the remainder of the island is expected to decrease by 25%.[47]

In 2017, Newfoundland Power's distribution plant on the North East Avalon accounted for approximately 17% of the Company's total distribution assets. The remaining 83% of the Company's distribution assets are used to serve customers located in the more rural parts of the province. The cost of serving a declining number of customers in rural areas will put increased pressure on the Company's ability to recover the investment in assets required to serve those customers.

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[45] See *Volume 2*, *Supporting Materials*, *Tab 3: Customer, Energy, and Demand Forecast*, Attachment A, page 3.

[46] The North East Avalon is located at the eastern most portion of Newfoundland Power's service territory. In 2016, the population of the North East Avalon was approximately 208,000. The population of the remainder of the island portion of the province was approximately 284,000. See *Regional Population Projections for Newfoundland and Labrador 2016-2036*, September 2017, Alvin Simms & Jamie Ward, Harris Centre Regional Analytics Laboratory (RAnLab), Memorial University.

[47] *Regional Population Projections for Newfoundland and Labrador 2016-2036*, September 2017, Alvin Simms & Jamie Ward, Harris Centre Regional Analytics Laboratory (RAnLab), Memorial University.

The combination of demographic changes within the Company's service territory has potential consequences for future investment recovery for Newfoundland Power.

Energy Sales

In the 2 years since the Company's *2016/2017 General Rate Application* was filed with the Board, Newfoundland Power has experienced a decline in energy sales. This is the first time in the Company's history that energy sales have declined in consecutive years.

Table 3-13 shows Newfoundland Power's annual energy sales growth for the period 2011 to 2020F.

Table 3-13:
Energy Sales Growth (%)
2011 to 2020P[48]

	2011	2012	2013	2014	2015	2016	2017	2018F	2019P	2020P
Sales Growth (%)	2.5	1.8	2.0	2.3	1.0	-0.1	-0.5	-0.1	-0.5	0.1

Average energy sales growth for the 2016 to 2020 period is expected to be -0.2%.[49] This compares to an average increase in sales of 1.9% for the 2011 to 2015 period.[50] The decline in sales growth reflects economic conditions, population and demographic changes, and customer usage patterns in the Company's service territory.

48 Energy sales growth in Table 3-13 for 2018, 2019 and 2020 is based on the Company's proposals in the Application. See *Volume 2, Supporting Materials, Customer, Energy and Demand Forecast*, Appendix B, line 37.
49 (-0.1% - 0.5% - 0.1% - 0.5% + 0.1%) / 5 = -0.2%.
50 (2.5% + 1.8% + 2.0% + 2.3% + 1.0%) / 5 = 1.9%.

Declining energy sales impact Newfoundland Power's risk profile in 2 ways: (i) it makes the Company less appealing to financial markets than similar utilities with higher growth potential; and (ii) it limits the Company's ability to manage inflationary increases in labour and materials, particularly between general rate applications.[51]

A shift from a period of sales growth to sales decline can be expected to put pressure on Newfoundland Power's ability to earn a fair return.[52]

Cost Flexibility

Newfoundland Power's purchased power costs represent approximately 65% of the cost to provide service to customers. Fixed costs, including finance charges and depreciation costs, constitute an additional 20%. These costs are largely beyond management control and, together, account for approximately 85% of the Company's revenue.

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51 Newfoundland Power establishes customer rates in a general rate application based on costs that are forecast to occur in a given year (the "test year"). These rates are in effect until a new general rate application, based on a new test year forecast, is filed with the Board. Traditionally, this occurs once every 3 years.

52 To address declining sales, some regulated gas and electric utilities have implemented revenue decoupling mechanisms. Revenue decoupling refers to adjustable pricing mechanisms that break the link between the amount of energy sold and the actual (allowed) revenue collected by the utility. Decoupling mechanisms enable a utility to recover its approved test year revenue requirement as its sales decline. During periods of sales growth, decoupling mechanisms have the effect of returning revenues in excess of a utility's approved revenue requirement back to customers.

Table 3-14 shows revenue and costs for Newfoundland Power on a ¢ per kWh basis for 1997, 2007, and 2017.

Table 3-14:
Revenue and Costs
1997, 2007, 2017
(¢ per kWh)

	1997	**2007**	**2017**	**Change (1997-2017)**
Revenue	7.74	10.80	11.35	+47%
Purchased Power Costs[53]	4.30	7.17	7.43	+73%
Fixed Costs[54]	1.75	1.91	2.17	+24%
Operating Costs	1.09	1.03	1.01	-7%

Over the period 1997 to 2017, the cost to provide service to customers has increased. On a ¢ per kWh basis, purchased power costs have increased by approximately 73% and fixed costs have increased by 24%. Operating costs, which are within management control, have declined by 7% on a ¢ per kWh basis. As a result of these changing cost dynamics, the Company has less flexibility to respond to business risks, including lower than forecast sales and unexpected expenses.

Muskrat Falls

Newfoundland Power is dependent upon Hydro for the bulk generation and transmission of electricity to its customers. The cost of Hydro's electricity supply is passed on to customers

[53] In 1997, purchased power costs totaled approximately $191 million. In 2017, these costs increased to approximately $440 million.

[54] Fixed costs include depreciation, employee future benefits, finance charges and income taxes.

through the rates charged by Newfoundland Power. In 2017, these wholesale supply costs were approximately twice Newfoundland Power's remaining costs.[55]

Purchased power costs from Hydro are expected to increase materially as costs associated with the Muskrat Falls project begin to be recovered in the coming years.[56] These costs will be recovered through Newfoundland Power's customer rates.[57]

Newfoundland Power's *2016/2017 General Rate Application* was the first time the Board considered Newfoundland Power's business risk in relation to the Muskrat Falls project.[58] Since the Board's 2016 review, the cost of the Muskrat Falls project has increased.

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55 Newfoundland Power's revenue in 2017 was approximately $672 million. Of this, approximately $440 million was for purchased power from Hydro.

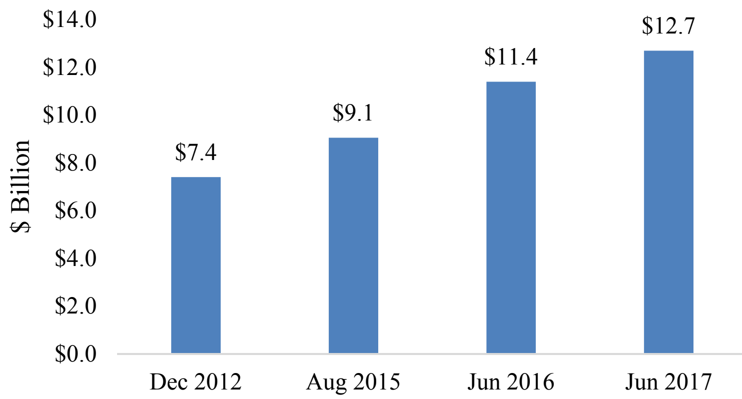
56 Muskrat Falls electricity rates are expected to be reflected in customer rates in the 2020-2021 timeframe.

57 The Government of Canada's November 30, 2012 loan guarantee with the Government of Newfoundland and Labrador requires that Hydro's regulated rates be sufficient in each year to recover the costs of electricity from the Muskrat Falls project. Provincial Government legislation dated December 22, 2012 granted Hydro the exclusive right to sell electricity to Newfoundland Power and Industrial customers on the island of Newfoundland.

58 Prior to the *2016/2017 General Rate Application*, Newfoundland Power's cost of capital had most recently been reviewed in its *2013/2014 General Rate Application*, filed on September 14, 2012. The Government of Newfoundland and Labrador sanctioned the Muskrat Falls project on December 17, 2012.

Figure 3-2 shows the increase in expected in-service capital costs for the Muskrat Falls project since it was first sanctioned in 2012.

Figure 3-2:
Muskrat Falls Projected In-Service Capital Cost
2012 to 2017



Since 2015, the in-service capital cost of the Muskrat Falls project has increased by approximately 40%, or $3.6 billion. This increase alone is greater than the combined book value of the current utility investment of Hydro and Newfoundland Power.[59]

In addition to the increased in-service capital costs, the annual base operating and maintenance (O&M) costs have increased. In its June 23, 2017 update, Nalcor Energy revised its annual O&M estimate from $34 million starting in 2018 to $109 million beginning in 2020.[60] These

[59] Newfoundland Power's forecast average rate base for year-end 2018 is expected to be approximately $1.1 billion and is shown in *Volume 1, Application, Company Evidence and Exhibits, Exhibit 3*, page 5 of 9. Hydro's 2018 average rate base for year-end 2018 is forecast to be approximately $2.3 billion as referenced in Hydro's *2017 General Rate Application*, page 4.8, Table 4-7: Average Rate Base. $1.1 billion + $2.3 billion = $3.4 billion.

[60] See Nalcor Energy's June 23, 2017 news release *Nalcor Energy provides update on Muskrat Falls Project* and slide 14 of Nalcor Energy's June 23, 2017 *Muskrat Falls Project Update* presentation.

forecast annual O&M costs are approximately 1.7 times higher than Newfoundland Power's annual operating costs.[61]

Expected increases in Newfoundland Power's electricity supply costs, and the rates that will be needed to recover these costs, can be expected to put pressure on Newfoundland Power's ability to earn a fair return.

Small Size

Newfoundland Power is a relatively small-sized, investor-owned utility. To finance its operations, the Company typically issues long-term first mortgage bonds of $75 million or less.[62] The general capital market requirement for inclusion in widely traded bond indices is $100 million. Issuances below this threshold reduce the number of potential debt investors for the Company and contribute to higher interest rates on long-term debt.[63]

The small size of Newfoundland Power and how it relates to the Company's financial flexibility has been recognized by the Board.[64] Further, the Board has previously determined that a strong equity component is needed to mitigate the impact of the Company's relatively small size and low growth potential.[65] The Company's small size relative to its peers continues to define the Company's risk profile.

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[61] Newfoundland Power's 2020 test year operating costs are forecast to be approximately $64 million. $109 million / $64 million = 1.70.

[62] In 2013 the Company issued its $70 million Series AN First Mortgage Bonds. In 2015, the Company issued its $75 million Series AO First Mortgage Bonds. Most recently, in 2017 the Company issued its $75 million Series AP First Mortgage Bonds.

[63] Newfoundland Power's $75 million Series AP First Mortgage Bond issue was privately placed with 4 institutional investors in June 2017.

[64] See Order No. P.U. 16 (1998-99), page 37.

[65] See Order No. P.U. 19 (2003), page 45.

Operating Environment

Newfoundland Power is primarily a distribution utility, currently serving approximately 267,000 customers on the island of Newfoundland, most of which are residential customers.[66] Approximately 68% of Newfoundland Power's domestic customers rely on electricity as their primary heating source.[67]

The Company's electrical system includes approximately 10,400 kilometres of distribution line and 2,100 kilometres of transmission line located throughout a 70,000 km^2 service territory. Most of the distribution and transmission infrastructure is overhead construction and is exposed to the environment.[68] The leading cause of outages that occur on an electrical system are related to adverse weather conditions, including wind and ice accumulation.[69]

Compared to other electric utilities, Newfoundland Power's service territory contains some of the most severe wind and ice conditions for populated regions of Canada.[70] These conditions

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66 At year-end 2017, the Company had 266,450 customers. Of those, 231,639 were domestic customers, 23,849 were general service customers and 10,962 were street and area lighting customers. By year-end 2018, the Company expects to serve 268,168 total customers.

67 Of Newfoundland Power's 231,639 domestic customers, 158,631 used electricity as the primary source of household heating (158,631 / 231,639 = 0.68, or 68%).

68 Approximately 97% of Newfoundland Power's distribution system and over 99% of the Company's transmission system is overhead construction.

69 CEA, *2017 Service Continuity Data on Distribution System Performance in Electrical Utilities.*

70 The principal design standard for distribution and transmission line design in Canada is the CSA standard *C22.3 No.1-15*, *Overhead Systems*. This standard recognizes 4 classifications of weather load conditions for ice accumulation, wind loading, and temperature. These are: (i) medium loading B; (ii) medium loading A; (iii) heavy; and (iv) severe. Newfoundland Power's service territory has *heavy* and *severe* loading classifications. Only 2 other provinces throughout Canada are identified as having severe weather loading areas. These are: (i) parts of northern and southern Manitoba; and (ii) rural parts of eastern Quebec, including the Gaspe Peninsula.

have resulted in large-scale outages to Newfoundland Power's customers.[71] The Company's load centre, located on the Avalon Peninsula, is exposed to the most severe weather conditions in Newfoundland Power's service territory.[72]

Customer outages, particularly during the winter season, can present a risk to the health and safety of the population. Newfoundland Power's operational response during periods of customer outages is to mobilize its workforce and restore power on a round-the-clock basis. This can result in relatively high costs and can increase the volatility of the Company's operating and capital costs. This is characteristic of the electric utility industry.[73]

Regulatory Mechanisms

Newfoundland Power utilizes Board-approved regulatory mechanisms to recover certain costs that are largely outside of management control. These include regulatory mechanisms to address variability of supply costs and employee future benefits. Newfoundland Power also has a regulatory mechanism that limits the Company's earnings in any given year.

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[71] Newfoundland Power's service territory experiences significant weather events that cause large-scale customer outages. In 2010, a March ice storm caused extensive damage to 8 of the Company's transmission lines on the Avalon and Bonavista peninsulas. Later that same year, Hurricane Igor caused outages to approximately 77,000 customers and left approximately 100 communities across the island isolated or in states of emergency. A wind storm in 2011 left approximately 41,000 customers without power across the island. In 2012, Tropical Storm Leslie caused damage to Newfoundland Power's electricity system throughout most of Eastern Newfoundland and the Avalon Peninsula. A severe winter storm in November 2013 caused power interruptions in Western and Central Newfoundland. In March 2017, a wind storm with gusts reaching approximately 180 km/h caused widespread outages to approximately 140,000 of the Company's customers.

[72] The weather loading conditions on the Avalon and Bonavista peninsulas are classified as *severe*.

[73] In its February 2005 report *After the Disaster: Utility Restoration Cost Recovery*, the Edison Electric Institute states: *"Because of the high costs utilities incur in their storm restoration efforts, there is a potential for large financial losses for individual utilities"* (page 15).

Utility supply costs are typically recovered by supply cost mechanisms.[74] Newfoundland Power's RSA is the principal supply cost mechanism. It ensures that variations in Hydro's production and marginal energy costs are recovered in, or credited to, Newfoundland Power's customer rates in a timely fashion. Supply mechanisms also include: (i) a Weather Normalization Reserve to normalize the effects of weather and hydrology; and (ii) a Demand Management Incentive ("DMI") Account. The DMI effectively limits the impacts on the Company of variability in demand supply cost to ±1% of test year wholesale demand charges. This equated to approximately ± $728,000 in 2017.[75]

In 2009 the Board approved the Company's Pension Expense Variance Deferral Account ("PEVDA").[76] Similarly, in 2010 the Board approved the OPEB Cost Variance Deferral Account.[77] These regulatory mechanisms address annual fluctuations in pension and OPEB costs that are beyond management's control.[78] Such mechanisms have been approved in other Canadian jurisdictions to address the increased volatility of employee future benefits costs.[79]

Newfoundland Power has an Excess Earnings Account which is credited with any earnings in excess of the upper limit of the allowed return on rate base as approved by the Board.[80] The sole purpose of the Excess Earnings Account is to protect customer interests by ensuring that

[74] A report on the Company's supply cost mechanisms was filed in Newfoundland Power's *2016/2017 General Rate Application (1st Revision), Volume 2, Exhibits and Supporting Materials, Reports, Tab 9.* Supply cost recovery practices for investor-owned distribution utilities in Canada were described in Appendix A to the report.

[75] See Order No. P.U. 10 (2018).

[76] See Order No. P.U. 43 (2009).

[77] See Order No. P.U. 31 (2010).

[78] This was recognized by the Board in respect of pension costs in Order No. P.U. 43 (2009): Reasons for Decision, page 9, lines 12-13 and 30-32.

[79] Employee future benefits cost recovery mechanisms are also in effect for utilities in Ontario, Alberta, and British Columbia.

[80] The upper limit on the allowed rate of return on rate base, as established by the Board in Order No. P.U. 19 (2003), is 18 basis points above that used for ratemaking purposes.

Newfoundland Power's earned returns do not materially exceed those approved by the Board for ratemaking purposes. This limits the Company's return on equity to approximately 40-50 basis points above the approved return for ratemaking purposes.[81]

Overall, the Company's regulatory mechanisms appear to be broadly consistent with existing Canadian utility practice.

3.3.3 Impact of Proposed Returns

Exhibit 5 in *Volume 1, Application, Company Evidence and Exhibits,* compares Newfoundland Power's forecast financial performance for 2019 and 2020 based on the Company's existing scenario and the proposals contained in this Application.

Table 3-15 provides a summary of Newfoundland Power's regulated returns under the Company's existing scenario and the proposals in this Application.

Table 3-15:
Comparative Rates of Return
2019 and 2020

	2019E	2019P	2020E	2020P
Return on Rate Base (%)	6.34	7.47	6.09	7.49
Return on Equity (%)	7.04	9.50	6.44	9.50

81 Sharing of earnings variances between utilities and customers has been a feature of some, but not all, performance-based ratemaking regimes in Canada. In British Columbia, sharing of positive and negative variances between approved and actual regulated earnings between customers and utilities has been part of performance-based regulatory regimes for gas and electric utilities. Alberta's current performance-based regulatory scheme, however, permits utilities to retain all earnings in excess of the allowed return; after utility returns on equity exceed the allowed return by 300 basis points (3%) for 2 consecutive years, the existing scheme may be re-examined.

Newfoundland Power's rates of return on rate base for 2019 and 2020, excluding the proposals in this Application, are 6.34% and 6.09%, respectively. This equates to a return on equity of 7.04% for 2019 and 6.44% for 2020. In this Application, Mr. James Coyne of Concentric Energy Advisors has provided an expert opinion on the Company's return on equity. Mr. Coyne recommends a fair rate of return on equity for Newfoundland Power of 9.5% based upon a capital structure with a 45% common equity component.[82]

Table 3-16 provides a summary of Newfoundland Power's credit metrics under the Company's existing scenario and the proposals in this Application.

Table 3-16:
Credit Metrics
Existing and Proposed
2019 and 2020

	2019E	**2019P**	**2020E**	**2020P**
Pre-tax Interest Coverage (times)	2.2	2.6	2.0	2.6
Cash Flow Interest Coverage (times)	3.7	4.0	3.7	4.1
Cash Flow Debt Coverage (%)	15.8	17.7	15.4	17.8

Maintaining Newfoundland Power's existing scenario results in deteriorating credit metrics for 2019 and 2020.

[82] See *Volume 2, Supporting Materials, Expert Evidence: Cost of Capital.*

With the proposals in this Application, the Company's credit metrics will more closely reflect the stable and consistent financial strength observed by Moody's[83] and DBRS.[84]

3.3.4 Automatic Adjustment Formula

In 1998, the Board adopted the Automatic Adjustment Formula (the "Formula") to make changes to the Company's return on equity between rate applications.[85] The Formula would adjust the return on equity based upon forecast changes in long Canada bond yields which served as a proxy for the risk free rate.

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83 In its January 31, 2018 Credit Opinion, filed in *Exhibit 4* to this Application, Moody's states: *"The stable rating outlook reflects the PUB's regulation of NPI which we consider credit supportive. We expect the regulatory environment to remain supportive to credit quality, with a suite of timely recovery mechanisms, along with our expectation that relatively stable cash flow generation and the capital structure of NPI will generate sustained CFO pre-WC to debt in the 17-20% range"* (page 2).

84 In its September 5, 2017 Rating Report for Newfoundland Power, filed in *Exhibit 4* to this Application, DBRS states: *"Newfoundland Power has maintained a solid financial profile, underpinned by the Company's reasonable financial leverage and stable cash flows. During the last 12 months ended June 30, 2017 (LTM 2017), Newfoundland Power's total debt in capital structure remained low at 54.3%, while its cash flow-to-debt and EBIT interest coverage ratios remained solid at 18.8% and 3.07 times, respectively"* (page 2).

85 Cost of capital formulas to determine return on equity for ratemaking purposes in Canada originated with the British Columbia Utilities Commission decision to adopt a formula in 1994. Following this, the National Energy Board and the Manitoba Public Utilities Board each adopted formulas to estimate the cost of equity for 1995. The predecessor to the Alberta Utilities Commission, the Ontario Energy Board, and the Regie de l'energie also adopted formulas over the period 1997 to 2004. The Board approved use of the Formula for Newfoundland Power in Order No. P.U. 16 (1998-99).

Figure 3-3 shows long Canada bond yields for the period April 2008 to April 2018.

Figure 3-3:
30-Year Canada Bond Yields[86]
April 2008 to April 2018

The Board suspended use of the Formula in April 2013 following Newfoundland Power's *2013/2014 General Rate Application*. The average long Canada bond yield for April 2013 was 2.37%. In its final order, the Board stated:

> *"While the Board continues to see the value of an automatic adjustment formula, the evidence is clear that the formula as it is currently structured may not result in a fair return for Newfoundland Power in the current circumstances. Long-term Canada bond yields are abnormally low which is particularly problematic in the operation of the automatic adjustment formula. In the absence of a clear relationship between the long-term Canada bond yield and the cost of equity it is difficult to see that the established return can be appropriately adjusted for 2015 without the exercise of further judgment."*[87]

Newfoundland Power's *2016/2017 General Rate Application* was filed in October 2015. The average long Canada bond yield during the month was 2.30%. Continued suspension of the Formula formed part of the *2016/2017 General Rate Application* settlement agreement reached

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[86] See https://ca.investing.com/rates-bonds/canada-30-year-bond-yield-historical-data.
[87] See Order No. P.U. 13 (2013), page 36, lines 38-44.

between Newfoundland Power and Consumer Advocate. Suspension of the Formula was subsequently approved by the Board until Newfoundland Power's next general rate application.[88]

For the month of April 2018, the average long Canada bond yield was 2.40%. This is consistent with long Canada bond yields in 2013 and 2016 when the Formula was suspended.

Given there has not been an appreciable change in the long Canada bond yields, Newfoundland Power proposes the continued suspension of the Formula in determining the Company's rate of return on equity between test years. This is consistent with current Canadian regulatory practice.[89]

3.4 REGULATORY ACCOUNTING MATTERS

General

In March 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update 2017-07 ("ASU 2017-07") – *Improving the Presentation of Net Periodic*

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88 See Order No. P.U. 18 (2016), page 10, lines 15-26.

89 The National Energy Board, Manitoba Public Utilities Board, Alberta Utilities Commission, and the Regie de l'energie have discontinued the use of automatic adjustment formulas. In 2013, the British Columbia Utilities Commission ("BCUC") reinstated use of an Automatic Adjustment Mechanism ("AAM") to adjust rates of return on equity for utilities within British Columbia. However, the AAM requires that long Canada bond yields reach a threshold of 3.8% before the mechanism will operate. Since the inception of the AAM, long Canada bond yields have remained below 3.8%, and the AAM has never operated (see BCUC Decision L-543-13). Unlike most regulators, the Ontario Energy Board ("OEB") did not abandon the use of a formulaic basis of determining rate of return on equity for utilities in Ontario. In 2009, the OEB concluded that this approach was necessary to be able to continue regulatory oversight of over 80 utilities in Ontario (see OEB Staff Report, EB-2009-0084, *Review of the Cost of Capital for Ontario's Regulated Utilities*, January 14, 2016).

Pension Cost and Net Periodic Post-retirement Benefit Cost (the "Update").[90] The Update affects how the Company accounts for pension costs in accordance with U.S. GAAP.[91]

The Update requires that only the current service cost component of pension and OPEB expense be eligible for capitalization.[92] The Update also provides guidance that the amount capitalized should reflect the proportion of labour costs that are related to capital work.[93]

The Update became effective for the Company on January 1, 2018.

Current Treatment

OPEB Costs

Newfoundland Power's capitalization of OPEB costs is consistent with the Update. The amount of OPEB current service cost that is capitalized is based on the proportion of the Company's internal labour costs that are related to capital work.[94] In 2019 and 2020, 46% of OPEB current service costs is forecast to be capitalized.[95]

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[90] The FASB is the independent organization that establishes financial accounting and reporting standards for public and private companies and not-for-profit organizations that follow accounting principles generally accepted in the United States ("U.S. GAAP").

[91] Newfoundland Power's financial statements are prepared in accordance with U.S. GAAP.

[92] Capitalization refers to the proportion of a cost that is considered a capital cost as opposed to an operating expense. The service cost component of pension and OPEB expense results from employee service in the current period. Other components of pension and OPEB expense include: (i) interest costs; (ii) amortization of past service costs; (iii) net actuarial losses; (iv) regulatory adjustments; and (v) expected return on plan assets.

[93] As per ASU 2017-07, FASB states: "*The service cost component of net periodic pension cost and net periodic postretirement benefit cost is the only component directly arising from employees' services provided in the current period. Therefore, when it is appropriate to capitalize employee compensation in connection with the construction or production of an asset, the service cost component applicable to the pertinent employees for the period is the relevant amount to be considered for capitalization.*"

[94] The accounting treatment of OPEB costs, including the methodology for capitalizing a portion of OPEB costs, was approved by the Board in Order No. P.U. 31 (2010).

[95] This capitalization rate has been consistent since the Board approved the capitalization of OPEB costs in 2010. The capitalization rate has ranged from 42% to 47% since that time.

Pension Costs

The Company capitalizes a portion of current service costs associated with its pension plan. This is consistent with the Update.[96] The capitalization rate is 11% rather than the 46% capitalization rate used for OPEB costs.[97]

Proposed Treatment – 2019/2020

The Company is proposing to revise the capitalization rate for pension expense to reflect the proportion of labour costs that are related to capital work. The capitalization rate is proposed to increase from 11% to 46% based on the overall Company labour allocation for 2019 and 2020.[98] The proposal is consistent with: (i) guidance provided in the Update; (ii) the current treatment for the capitalization of OPEB costs; and (iii) industry practice.[99]

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[96] Prior to 2018, the Company capitalized a portion of all components of pension expense. In 2018, only a portion of the current service cost component of pension expense is forecast to be capitalized. The change in methodology for 2018 resulted in a reduction of $59,000 in the amount capitalized.

[97] The 11% capitalization rate used for pension costs has been reflected in customer rates since 1999, following the 5-year phase-in of changes in the Company's GEC methodology approved by the Board in Order No. P.U. 3 (1995-96).

[98] Similar to the capitalization of OPEB costs, the percentage will change from year to year based on the Company's labour cost allocation between capital and operating expense for that year.

[99] In August 2017, FortisBC filed its *Annual Review for 2018 Rates* with the British Columbia Utilities Commission ("BCUC"). The filing included a change in accounting of pension and OPEB costs in line with ASU 2017-07, under which only the current service cost component of pension and OPEB expense is eligible for capitalization. FortisBC allocated 52% of their current service costs to capital in their 2018 forecast based on a reasonable allocation of capital and operating labour. The BCUC approved the *Annual Review for 2018 Rates* in February 2018 in Order No. G-38-18.

Table 3-17 shows existing and proposed capitalization of pension expense in 2019 and 2020.

Table 3-17:
2019 and 2020 Pension Expense - Capital
($000s)

		2019E	**2019P**	**2020E**	**2020P**
Current Service Costs[100]	A	6,560	6,560	6,601	6,601
Capitalization Rate	B	11%	46%	11%	46%
Pension Expense Capitalized[101]	C = A x B	721	3,018	722	3,036
Change in Capitalization[102]		**2,297**		**2,314**	

The proposed change in the capitalization rate increases the amount of pension expense that is capitalized by approximately $2.3 million in 2019 and 2020.

Table 3-18 shows the impact of the Company's proposal on pension expense included in 2019 and 2020 revenue requirements.

Table 3-18:
2019 and 2020 Pension Expense - Operating
($000s)

		2019E	**2019P**	**2020E**	**2020P**
Total Pension Expense[103]	A	2,882	2,882	1,263	1,263
Pension Expense Capitalized[104]	B	721	3,018	722	3,036
Pension Expense - Operating	C = A - B	2,161	(136)	541	(1,773)
Change in Pension Expense - Operating[105]		**(2,297)**		**(2,314)**	

100 Current service costs include $4.0 million in 2019 and $3.9 million in 2020 associated with the Company's defined benefit pension plans and $2.5 million in 2019 and $2.7 million in 2020 associated with the Company's defined contribution pension plans.

101 The current service portion of pension costs are capitalized through an indirect GEC transfer from operating costs. This is consistent with Order No. P.U. 3 (1995-96).

102 For 2019, $3,018 – $721 = $2,297. For 2020, $3,036 – $722 = $2,314.

103 See *Table 3-5: Employee Future Benefits Expense*.

104 See *Table 3-17: 2019 and 2020 Pension Expense – Capital*, line C.

105 For 2019, -$136 – $2,161 = -$2,297. For 2020, -$1,773 – $541 = -$2,314.

The Company's proposal reduces operating costs by approximately $2.3 million in 2019 and 2020.

2019 and 2020 Revenue Requirements

Newfoundland Power's proposed change to pension capitalization will affect 2019 and 2020 revenue requirements related to pension expense, depreciation, income taxes and return on rate base.[106]

Table 3-19 shows the change in the 2019 and 2020 revenue requirements based on the Company's proposal.

Table 3-19:
2019 and 2020 Revenue Requirements
Proposed Pension Capitalization
($000s)

	2019P	**2020P**
Pension Expense - Operating[107]	(2,297)	(2,314)
Depreciation Expense	36	111
Income Taxes	12	24
Return on Rate Base	47	98
Change in Revenue Requirement	**(2,202)**	**(2,081)**

The proposed change in pension capitalization will reduce 2019 and 2020 revenue requirements by approximately $2.2 million and $2.1 million, respectively. This represents a decrease of approximately 0.3%.

[106] The reduction in pension expense is shown in Operating Costs in *Volume 1, Application, Company Evidence and Exhibits, Exhibit 7*, line 3. Pension expense is capitalized through the GEC transfer from operating costs, consistent with Order No. P.U. 3 (1995-96).

[107] See *Table 3-18: 2019 and 2020 Pension Expense – Operating.*

3.5 REGULATORY AMORTIZATIONS

3.5.1 Overview

Table 3-20 summarizes the amortization of regulatory deferrals approved by the Board and the amortization of regulatory deferrals proposed in this application.

Table 3-20:
Amortization of Regulatory Deferrals
***Pro forma* Revenue Requirement Impact**
2015 to 2020F
($000s)

	2015	2016	2017	2018F	2019P	2020P
2011 & 2012 Cost Recovery Deferrals[108]	1,575	-	-	-	-	-
2012 Cost of Capital Recovery Deferral[108]	829	-	-	-	-	-
2013/2014 Hearing Costs Deferral[108]	322	-	-	-	-	-
Weather Normalization Reserve[108]	(2,335)	-	-	-	-	-
2013 Revenue Shortfall[108]	1,586	-	-	-	-	-
2016/2017 Hearing Costs Deferral[109]	-	171	341	341	-	-
2016 Revenue Surplus[110]	-	2,064	(1,032)	(1,032)	-	-
2019 Hearing Costs Deferral	-	-	-	-	294	353
2019 Revenue Surplus[111]	-	-	-	-	649	(324)
Revenue Requirement Impact	**1,977**	**2,235**	**(691)**	**(691)**	**943**	**29**

108 These amortizations were agreed in Newfoundland Power's *2013/2014 General Rate Application* and approved by the Board in Order No. P.U. 13 (2013).

109 In Order No. P.U. 18 (2016), the Board approved amortization of Newfoundland Power's *2016/2017 General Rate Application* hearing costs in an amount up to $1.0 million for the period July 1, 2016 to December 31, 2018, with any hearing costs billed to Newfoundland Power over this amount to be collected through the RSA.

110 In Order No. P.U. 25 (2016), the Board approved final customer rates resulting from the Company's *2016/2017 General Rate Application*. This included an amortization of a revenue surplus for 2016 resulting from the July 1, 2016 implementation. See Section 3.3 of the Company's *2016/2017 GRA Compliance Report* filed on June 17, 2016.

111 Amortization of $919,000 related to the March 1, 2019 rate implementation date is proposed in this Application over a 34-month period. This represents approximately $27,000 per month. For 2019, it represents amortization over 10 months, or approximately $270,000 ($919,000 - $270,000 = $649,000). For 2020 and 2021, this represents approximately $324,000 per year. See *Section 3.5.3: 2019 Revenue Surplus.*

3.5.2 Hearing Costs

Newfoundland Power estimates that $1.0 million in costs will be incurred and billed to the Company by the Board and Consumer Advocate as a result of the *2019/2020 General Rate Application*. Consistent with previous Board practice, Newfoundland Power proposes to recover these costs in customer rates over a 34-month period ending December 31, 2021.[112] The Company also proposes to recover any Board and Consumer Advocate costs in excess of $1.0 million through the RSA.[113]

3.5.3 2019 Revenue Surplus

Implementation of customer rates beginning on March 1, 2019 based on the proposed 2020 revenue requirement would result in a $919,000 over recovery of the proposed 2019 revenue requirement. Newfoundland Power is proposing to amortize this amount over 34 months commencing on March 1, 2019 and ending December 31, 2021. The proposed treatment of the 2019 revenue surplus is consistent with past practice of the Board.[114]

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112 In the past, the Board has ordered recovery of Application costs over a 3-year period on a number of occasions. See Order Nos. P.U. 7 (1996-1997), P.U. 36 (1998-1999), P.U. 19 (2003), P.U. 32 (2007), P.U. 43 (2009), P.U. 13 (2013), and P.U. 18 (2016).

113 Recovery of additional Board and Consumer Advocate costs in the RSA formed part of the March 10, 2016 settlement agreement in relation to Newfoundland Power's *2016/2017 General Rate Application*. The settlement agreement was reached between Newfoundland Power, the Consumer Advocate and Board's hearing counsel and subsequently approved by the Board in Order No. P.U. 18 (2016).

114 In Order No. P.U. 13 (2013), the Board approved recovery of a forecast revenue shortfall of an estimated $980,000 resulting from the implementation of new rates after January 1, 2013. In Order No. P.U. 18 (2016), the Board approved recovery of a forecast revenue shortfall of an estimated $1,410,000 resulting from the implementation of new rates after January 1, 2016. In Order No. P.U. 25 (2016) the Board approved final customer rates resulting from the Company's *2016/2017 General Rate Application*. This included an amortization of a revenue surplus for 2016 resulting from the July 1, 2016 implementation.

SECTION 4: RATE BASE & REVENUE REQUIREMENT

4.1 OVERVIEW

This section of evidence addresses the Company's forecast 2019 and 2020 average rate base and revenue requirements.

Based on the Company's proposals in this Application, the forecast 2019 and 2020 average rate base is approximately $1,146 million and $1,179 million, respectively.

Based on the Company's proposals in this Application, the forecast 2019 and 2020 revenue requirements are approximately $661 million and $664 million, respectively.

To generate the revenue necessary to meet the Company's forecast revenue requirements in 2019 and 2020, an average increase in existing customer rates of approximately 1.2%, effective March 1, 2019, will be required.

4.2 2019 AND 2020 RATE BASE

Exhibit 6 in *Volume 1, Application, Company Evidence and Exhibits*, shows Newfoundland Power's forecast 2019 and 2020 average rate base.

Newfoundland Power's forecast 2019 and 2020 average rate base, as set out in this Application, including rate base allowances, is calculated in accordance with Board orders and regulatory practice.[1]

[1] The report *2019 and 2020 Rate Base Allowances* is found in *Volume 2, Supporting Materials, Reports, Tab 2.*

The Company's forecast 2019 and 2020 average rate base is approximately $1,146 million and $1,179 million, respectively.

Changes to the Company's average rate base are principally the result of: (i) plant investment, which includes annual capital expenditures;[2] and (ii) depreciation expense.[3] Forecast 2019 and 2020 average rate base include the Company's forecast capital expenditures and is calculated in accordance with established practice and Board orders.[4]

4.3 2019 AND 2020 REVENUE REQUIREMENTS

4.3.1 Summary of Revenue Requirements

Exhibit 7 in *Volume 1, Application, Company Evidence and Exhibits*, shows Newfoundland Power's 2019 and 2020 forecast revenue requirements.[5]

The Company's revenue requirement is forecast to be approximately $661 million in 2019 and $664 million in 2020.

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[2] Each year, the Company's capital expenditures for the following year are considered and approved by the Board. Further detail on the capital forecast is provided in the *2018 Capital Budget Application* filed on July 7, 2017.

[3] Annual depreciation expense is currently calculated using the composite depreciation rates approved by the Board in Order No. P.U. 18 (2016).

[4] The forecast capital expenditures for 2019 and 2020 are described in the *2018 Capital Budget Application*. The Board approved this application in Order No. P.U. 37 (2017).

[5] *Exhibit 9* in *Volume 1, Application, Company Evidence and Exhibits*, displays the 2019 and 2020 revenue requirements in the absence of the proposals contained in this Application.

Table 4-1 shows a summary of Newfoundland Power's 2019 and 2020 forecast revenue requirements and the revenue required to be recovered from customer rates.

Table 4-1:
Summary of Revenue Requirements
2019F & 2020F
($000s)

	2019F	**2020F**
Power Supply Cost	429,949	429,144
Operating Costs[6]	62,679	64,610
Employee Future Benefit Costs	9,080	7,566
Deferred Cost Recoveries and Amortizations	649	(324)
Depreciation	62,350	64,908
Income Taxes[6]	20,320	21,078
Return on Rate Base	85,635	88,362
Revenue Requirement	**670,662**	**675,344**
Adjustments		
Other Revenue	(5,612)	(5,594)
Interest on Security Deposits	18	18
Energy Supply Cost Variance Adjustments	1,064	-
CDM Program Amortization	(4,665)	(5,650)
Revenue Requirement from Rates	**661,467**	**664,118**

[6] For revenue requirement purposes, operating costs and income taxes do not include non-regulated expenses.

4.3.2 Costs and Depreciation

Table 4-2 shows forecast 2019 and 2020 power supply costs.

Table 4-2:
Power Supply Costs
2019F & 2020F
($000s)

	2019F	**2020F**
Existing	430,627	430,644
Elasticity Impact	(678)	(1,500)
Proposed	**429,949**	**429,144**

Table 4-3 shows forecast 2019 and 2020 operating costs.[7]

Table 4-3:
Operating Costs
2019F & 2020F
($000s)

	2019F	**2020F**
Existing	64,682[8]	66,571[9]
2019-2020 Pension Capitalization[10]	(2,297)	(2,314)
2019 Hearing Costs[11]	294	353
Proposed	**62,679**	**64,610**

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7 *Exhibits 1 and 2* in *Volume 1, Application, Company Evidence and Exhibits*, show the forecast gross operating costs for 2019 and 2020. These are reviewed in detail in *Section 2.4*: *Operating and Capital Costs.*

8 Existing operating costs in 2019 include: (i) gross operating costs of approximately $62.7 million (see *Exhibits 1 and 2*); (ii) plus amortization of Conservation and Demand Management ("CDM") costs of approximately $4.7 million as approved by the Board in Order No. P.U. 13 (2013); (iii) less GEC of approximately $2.7 million.

9 Existing operating costs in 2020 include: (i) gross operating costs of approximately $63.6 million (see *Exhibits 1 and 2*); (ii) plus amortization of CDM costs of approximately $5.7 million as approved by the Board in Order No. P.U. 13 (2013); (iii) less GEC of approximately $2.7 million.

10 See *Table 3-18: 2019 and 2020 Pension Expense – Operating*. Pension costs are capitalized through an indirect GEC transfer from operating costs. This is consistent with Order No. P.U. 3 (1995-96).

11 See *Section 3.5.2: Hearing Costs*.

Table 4-4 shows forecast 2019 and 2020 employee future benefits costs.

Table 4-4:
Employee Future Benefits Costs
2019F & 2020F
($000s)

	2019F	**2020F**
Pension Plans[12]	2,882	1,263
OPEB[13]	6,198	6,303
Proposed	**9,080**	**7,566**

Table 4-5 shows forecast 2019 and 2020 deferred cost recoveries and amortizations.

Table 4-5:
Deferred Cost Recoveries and Amortizations
2019F & 2020F
($000s)

	2019F	**2020F**
2019 Revenue Surplus[14]	649	(324)
Proposed	**649**	**(324)**

[12] See *Section 3.2.4: Employee Future Benefits, Pensions.*
[13] See *Section 3.2.4: Employee Future Benefits, OPEB.*
[14] The 2019 revenue surplus of $919,000 related to the March 1, 2019 rate implementation date is proposed to be amortized evenly over a 34-month period from 2019 to 2021.

Table 4-6 shows forecast 2019 and 2020 depreciation costs.

Table 4-6:
Depreciation Costs
2019F & 2020F
($000s)

	2019F	2020F
Existing[15]	62,314	64,797
2019-2020 Pension Capitalization[16]	36	111
Proposed Depreciation	**62,350**	**64,908**

Table 4-7 shows forecast 2019 and 2020 income taxes.

Table 4-7:
Income Taxes
2019F & 2020F
($000s)

	2019F	2020F
Existing[17]	15,814	14,985
Tax Effects of Application Proposals[18]	4,506	6,093
Proposed[19]	**20,320**	**21,078**

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15 Depreciation rates are based on the *2014 Depreciation Study* approved by the Board in Order No. P.U. 18 (2016). See *Section 3.2.3: Depreciation*.

16 See *Section 3.4: Regulatory Accounting Matters, Table 3-19*.

17 See *Exhibit 5* in *Volume 1, Application, Company Evidence and Exhibits*, page 1 of 9, line 22.

18 The tax effects of the Application proposals are as follows:

	($000s)	
	2019F	2020F
Increase in Forecast Revenue Requirement from Rates, *Exhibit 7*, line 21	5,626	6,659
Change in Transfers to the RSA, *Exhibit 7*, lines 17-18	9,937	12,395
Increase in Taxable Revenue	15,563	19,054
Change in Tax Deductible Expenses (i.e. power supply, operating and finance charges)	(840)	1,068
Increase in Taxable Income	14,723	20,122
Tax Rate	30.0%	30.0%
Change in Cash Income Taxes	4,417	6,037
Change in Future Income Taxes	89	56
Change in Total Income Taxes	**4,506**	**6,093**

19 See *Exhibit 5* in *Volume 1, Application, Company Evidence and Exhibits*, page 1 of 9, line 22.

4.3.3 Return on Rate Base

Exhibit 8 in *Volume 1, Application, Company Evidence and Exhibits*, shows Newfoundland Power's proposed 2019 and 2020 return on rate base.

Table 4-8 summarizes the proposed 2019 and 2020 return on rate base and rate of return on rate base.

Table 4-8:
Return on Rate Base
2019F & 2020F
($000s)

	2019F	**2020F**
Forecast Average Rate Base	1,146,293[20]	1,179,357[21]
Forecast Regulated Returns		
Debt	36,214	37,424
Preferred Equity	552	552
Common Equity	48,869	50,386
Return on Rate Base	**85,635**	**88,362**
Rate of Return on Rate Base (%)	**7.47**[22]	**7.49**[23]

[20] 2019F average rate base is shown in *Exhibit 6* in *Volume 1, Application, Company Evidence and Exhibits*.
[21] 2020F average rate base is shown in *Exhibit 6* in *Volume 1, Application, Company Evidence and Exhibits.*
[22] The forecast rate of return on rate base for 2019 is calculated as ($85,635 / $1,146,293 = 7.47%), as shown in *Exhibit 8* in *Volume 1, Application, Company Evidence and Exhibits.*
[23] The forecast rate of return on rate base for 2020 is calculated as ($88,362 / $1,179,357 = 7.49%), as shown in *Exhibit 8* in *Volume 1, Application, Company Evidence and Exhibits.*

4.3.4 Deductions from Revenue Requirement

Table 4-9 shows the forecast 2019 and 2020 deductions from revenue requirement.

Table 4-9:
Deductions from Revenue Requirement
2019F & 2020F
($000s)

	2019F	**2020F**
Other Revenue	(5,612)[24]	(5,594)[25]
Transfers to the RSA	(3,601)[26]	(5,650)[27]
Interest on Security Deposits[28]	18	18
Proposed	**(9,195)**	**(11,226)**

4.3.5 Required Revenue Increase

Table 4-10 shows a forecast increase in revenue from rates of approximately $6.2 million required to meet the Company's proposed 2019 revenue requirement and approximately $8.0 million required to meet the Company's proposed 2020 revenue requirement.

Table 4-10:
Required Revenue Increases
2019F & 2020F
($000s)

	2019F	**2020F**
Proposed Revenue From Rates	**661,467**	**664,118**
Revenue From Existing Rates	(655,841)	(657,459)
Elasticity Impacts[29]	607	1,301
Required Increase in Revenue from Rates	**6,233**	**7,960**

24 See *Exhibit 5* in *Volume 1, Application, Company Evidence and Exhibits*, page 1 of 9, line 11.
25 See *Exhibit 5* in *Volume 1, Application, Company Evidence and Exhibits*, page 1 of 9, line 11.
26 The 2019 transfers to the RSA reflect a $1,064,000 balance in the Energy Supply Cost Variance Reserve at March 1, 2019 and $4,665,000 related to the amortization of CDM program costs.
27 The 2020 transfers to the RSA reflect $5,650,000 related to the amortization of CDM program costs.
28 Interest on customer security deposits is not included in the determination of revenue requirements.
29 See *Exhibit 9* in *Volume 1, Application, Company Evidence and Exhibits*.

SECTION 5: CUSTOMER RATES

5.1 OVERVIEW

The number of customers served by Newfoundland Power is forecast to increase by 0.6% in each of 2018, 2019 and 2020. Energy sales are forecast to decrease by 0.1% in 2018 and 0.5% in 2019, and increase by 0.1% in 2020. Demand is forecast to increase by 0.6% in 2018 and decrease by 0.5% in 2019 and 0.2% in 2020.

In this Application, the Company seeks an average increase in customer rates of 1.2%, effective March 1, 2019. It is proposed that the average increase be applied to each rate class.

This section of the evidence details: (i) a proposal to increase the cost differential between Basic Customer Charges for Rate 2.1; and (ii) the rate design proposed for the introduction of a Light Emitting Diode ("LED") service offering for Street and Area Lighting customers.

Newfoundland Power introduced its Net Metering Service Option on July 1, 2017. This section of evidence provides an update on customer participation in this service option.

5.2 CUSTOMER, ENERGY AND DEMAND FORECAST

5.2.1 Customers Served

Newfoundland Power is the primary distributor of electricity on the Island Interconnected System and is responsible for retail pricing for the approximately 290,400 customers served by the system.[1]

Table 5-1 shows the forecast percentage of total customers and energy sales by rate class for the 2020 test year.

Table 5-1:
Newfoundland Power Customer Base
2020F

Rate	Class of Service	% of Total Customers	% of Total Energy Sales
1.1	Domestic	86.9	60.8
2.1	General Service 0-100 kW (110 kVA)	8.5	13.5
2.3	General Service 110-1000 kVA	0.5	17.6
2.4	General Service 1000 kVA and Over	-[2]	7.6
4.1	Street and Area Lighting	4.1	0.5
Total		**100.0**	**100.0**

The majority of customers served by Newfoundland Power are Domestic service customers. Approximately 61% of Newfoundland Power's annual energy sales are to Domestic service customers.

[1] Hydro serves approximately 23,900 customers on the Island Interconnected System. Those customers pay rates that are the same as those of Newfoundland Power's customers. The Company's rate design practices therefore affect all retail electricity customers on the Island Interconnected system.

[2] The 60 customers in Rate 2.4 comprise less than 0.01% of total customers.

5.2.2 Forecast

Newfoundland Power's *Customer, Energy and Demand Forecast* is found in *Volume 2, Supporting Materials, Reports, Tab 3*.

The Company's *Customer, Energy and Demand Forecast* reflects the impact of the proposals in this Application.[3] The forecast number of customers and their load requirements are primary inputs used to determine revenue from customer rates.

Table 5-2 shows the Company's actual number of customers for 2017 and forecast for 2018, 2019 and 2020.

Table 5-2:
Forecast Number of Customers
2017 to 2020F

	2017	**2018F**	**2019F**	**2020F**
Domestic	231,639	233,125	234,419	235,736
General Service				
0-100 kW (110 kVA)	22,522	22,712	22,882	23,052
110-1000 kVA	1,266	1,256	1,262	1,269
1000 kVA and Over	61	59	60	60
Total General Service	23,849	24,027	24,204	24,381
Street and Area Lighting	10,962	11,016	11,060	11,105
Total Customers	**266,450**	**268,168**	**269,683**	**271,222**

The number of customers is forecast to increase by 0.6% in each of 2018, 2019 and 2020.

[3] See Appendices B and C to the *Customer, Energy and Demand Forecast,* found in *Volume 2, Supporting Materials, Reports, Tab 3.*

Table 5-3 shows the Company's actual energy sales for 2017 and forecast for 2018, 2019 and 2020 based on proposed customer rates.

Table 5-3:
Energy Sales Forecast
2017 to 2020F
(GWh)

	2017	**2018F**	**2019F**	**2020F**
Domestic	3,644.8	3,635.3	3,581.6	3,571.6
General Service				
0-100 kW (110 kVA)	793.6	796.2	791.4	795.6
110-1000 kVA	1,010.2	1,023.6	1,031.8	1,038.3
1000 kVA and Over	440.8	426.9	445.3	448.7
Total General Service	2,244.6	2,246.7	2,268.5	2,282.6
Street and Area Lighting	32.8	33.0	32.8	32.3
Total Energy Sales	**5,922.2**	**5,915.0**	**5,882.9**	**5,886.5**

Energy sales are forecast to decrease by 0.1% in 2018 and 0.5% in 2019, and increase by 0.1% in 2020.[4] The forecast for 2020 includes the impact of a leap year, which positively impacts sales growth by approximately 0.3%.[5]

[4] The sales forecast includes elasticity effects of 6.1 GWh in 2019 and 12.8 GWh in 2020 as a result of the proposed March 1, 2019 average rate increase of 1.2%.

[5] Excluding the extra day provided by the leap year, forecast energy sales would decline by 0.2% in 2020.

Table 5-4 shows the Company's actual demand for 2017 and forecast for 2018, 2019 and 2020.

Table 5-4:
Demand Forecast
2017 to 2020F
(MW)

	2017	**2018F**	**2019F**	**2020F**
Native Peak[6]	1,384.9	1,392.7	1,385.2	1,382.3
Purchased[7]	1,254.5	1,262.4	1,254.9	1,251.9

Demand is forecast to increase by 0.6% in 2018 and decrease by 0.5% in 2019 and 0.2% in 2020. Demand purchases from Hydro are forecast to increase by 0.6% in 2018 and decrease by 0.6% in 2019 and 0.2% in 2020.

5.3 RATE CHANGE PLAN

5.3.1 Embedded Cost of Service Study

Newfoundland Power assesses the fairness of its customer rates by comparing the revenue collected from each class with the cost to serve that class, as determined through an embedded cost of service study (the "revenue-to-cost ratio").

The Company has prepared an embedded cost of service study based on 2016 actual costs. The Cost of Service Study is provided in *Volume 2, Supporting Materials, Reports, Tab 4*.

6 Native peak is the maximum demand served by Newfoundland Power. The 2017 native peak reflects the forecast for the winter period of December 2017 to March 2018.

7 Purchased demand is the native peak less the 11 MW curtailment credit and the 119.3 MW generation credit provided for in Hydro's wholesale rate structure.

Table 5-5 shows the revenue-to-cost ratio for each rate class as indicated by the most recent Cost of Service Study.

Table 5-5:
Cost of Service Study
Revenue-to-Cost Ratios

Class of Service	Rate Code	Revenue-to-Cost Ratios (%)
Domestic	1.1	96.0
General Service 0-100 kW (110 kVA)	2.1	108.4
General Service 110-1000 kVA	2.3	109.2
General Service 1000 kVA and Over	2.4	104.3
Street and Area Lighting	4.1	107.7

Maintaining revenue-to-cost ratios for each class within a range of 90% to 110% has been an accepted approach to achieving fairness in rate design by avoiding undue cross-subsidization among the various classes.[8] Table 5-5 shows the revenue-to-cost ratio for each Class of Service is between 90% and 110%. Based on this, Newfoundland Power is proposing to apply the same rate increase to customers served under each Class of Service.

5.3.2 Marginal Cost Outlook

Historically, Newfoundland Power has designed rates with consideration of marginal energy and capacity costs to ensure rates reasonably reflect marginal cost.[9] This is consistent with sound ratemaking principles.[10]

[8] This is consistent with the views of the Board as expressed in Order No. P.U. 7 (1996-97), which states: *"The Board agrees with the philosophy that it is not necessary to achieve a 100% revenue to cost ratio for all classes and takes no exception to a variance of up to 10%…."*

[9] A primary justification of the *Retail Rate Review*, agreed to as part of the settlement of Newfoundland Power's *2008 General Rate Application*, was the consideration of new rate designs to encourage increased energy conservation and efficiency. See Order No. P.U. 32 (2007), page 51-52.

[10] See, for example, Bonbright, Danielsen and Kamerschen, *Principles of Public Utility Rates (2nd ed.)*, Public Utilities Reports (1988), page 382, *et.seq.*

The Muskrat Falls project will be the primary source of any additional power supply requirements for Newfoundland Power once it is commissioned. The cost of Muskrat Falls production and associated transmission systems remains unclear. This adds uncertainty to Newfoundland Power's marginal cost outlook.

Hydro has provided reports to the Board relating to system marginal costs following completion of the Muskrat Falls project and interconnection to the North American grid.[11] Hydro has also provided a system marginal cost estimate for 2019. Hydro's 2019 average hourly marginal cost estimates of capacity and energy vary between approximately $40 per MWh to $80 per MWh depending on the time of year. Hydro plans to update its marginal cost projection prior to filing its cost of service methodology review application.[12]

The current uncertainty associated with marginal capacity and energy costs for the Island Interconnected System suggests that no material increases or decreases to specific rate components to reflect marginal costs would be appropriate at this time.

5.4 PROPOSED RATES

5.4.1 General

Schedule A to the Application sets out Newfoundland Power's proposed customer rates to be effective March 1, 2019.

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[11] Hydro filed its *Marginal Cost Study – Part I* on December 29, 2015 and its *Marginal Cost Study - Part II* on February 26, 2016.

[12] This information was provided in Hydro's response to Requests for Information CA-NLH-081 and NP-NLH-239 from Hydro's *2017 General Rate Application*.

A report on *Customer Rate Impacts* for the Domestic and General Service classes is provided in *Volume 2, Supporting Materials, Reports, Tab 5*.

Exhibit 9 in *Volume 1, Application, Company Evidence and Exhibits,* provides a reconciliation of Newfoundland Power's forecast revenue from rates to the Company's revenue requirements for 2019 and 2020.

Exhibit 10 in *Volume 1, Application, Company Evidence and Exhibits,* provides the computation of the average increase in customer rates of 1.2% proposed by the Company.

Exhibit 11 in *Volume 1, Application, Company Evidence and Exhibits,* provides a comparison of Newfoundland Power's existing and proposed customer rates.[13]

5.4.2 Introduction of LED Street and Area Lighting

Newfoundland Power is proposing to introduce rates for LED street and area lighting. A report describing the Company's assessment of LED street lights is provided in *Volume 2, Supporting Materials, Reports, Tab 7*.

[13] The existing and proposed rates reflect the Rate Stabilization Adjustment and the Municipal Tax Adjustment ("MTA") factors effective July 1, 2017.

Proposed LED street and area lighting rates are categorized in 4 ways, corresponding to existing High Pressure Sodium ("HPS") street light fixtures with similar lighting outputs. These are:

(i) *LED 100 (7,500 – 10,500 lumens)*

(ii) *LED 150 (13,000 – 16,000 lumens)*

(iii) *LED 250 (22,000 – 25,000 lumens)*

(iv) *LED 400 (43,500 – 46,500 lumens)*

LED 100 (7,500 – 10,500 lumens) street lights provide similar lighting output as 100W HPS fixtures. Similarly, LED 150, LED 250 and LED 400 street lights provide similar lighting outputs as 150W, 250W and 400W HPS fixtures, respectively.

To develop the proposed rates, the electricity usage for each category is based on the fixtures the Company plans to install. Table 5-6 shows the fixture wattage and average installations forecast to be in service in 2020.

Table 5-6:
2020 Forecast Installed LED Fixtures

Rate Category	Fixture Wattage	Quantity
LED 100	41 W 54 W	579 2,537
LED 150	69 W	374
LED 250	113 W	98
LED 400	158 W	27

Table 5-7 provides a comparison of the proposed rates for HPS and LED street lights.

Table 5-7:
Proposed Street and Area Lighting Rates[14]

HPS Rate Category	Rate	LED Rate Category	Rate	% Reduction
100W HPS	$17.24	LED 100	$15.85	8%
150W HPS	$21.27	LED 150	$17.30	19%
250W HPS	$29.69	LED 250	$22.11	26%
400W HPS	$40.99	LED 400	$24.97	39%
100W PT HPS[15]	$18.57	N/A	-	-

The proposed LED rates are between 8% and 39% less than equivalent HPS rates. The methodology used to determine the Street and Area Lighting rates is provided in *Volume 2, Supporting Materials, Reports, Tab 7*.

To accommodate the application of the Rate Stabilization Adjustment to LED street and area lighting rates, it is necessary to change the Rate Stabilization Clause. The proposed change to the Rate Stabilization Clause is provided in *Volume 1, Application, Company Evidence and Exhibits, Exhibit 12*.

5.4.3 Changes to Rate Components

Domestic

The Company is proposing an increase to customers served under Domestic Service Rate 1.1 and Optional Seasonal Rate 1.1S equal to the overall average increase of 1.2%.

[14] Rates include the Rate Stabilization Adjustment and the MTA.
[15] An LED equivalent for the Company's 100W HPS post top fixtures has not yet been determined.

It is proposed that the Basic Customer Charges, Energy Charge, and Minimum Monthly Charges for Domestic Rate 1.1 be increased by the average Domestic Class increase to the extent possible.[16]

Rate 2.1 General Service (0-100kW (110 KVA))

The Company is proposing an increase to customers served under General Service Rate 2.1 equal to the overall average increase of 1.2%.

Energy, Demand and Maximum Monthly Charges

It is proposed that the Energy Charges, Demand Charges and Maximum Monthly Charge be subject to the overall Rate 2.1 Class increase to the extent possible.[17]

Basic Customer Charges

Newfoundland Power introduced separate Basic Customer Charges under General Service Rate 2.1 as part of its *2016/2017 General Rate Application*.[18] This was consistent with the *Retail Rate Review* previously conducted by the Company in consultation with the Board, Consumer

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[16] Newfoundland Power's rate design requires that a cost differential be maintained between certain rate components to reflect differences in the cost of providing services. The Company is proposing to maintain a $5.00/month differential for Basic Customer Charges within Rate 1.1 Domestic Service for: (i) services not exceeding 200 Amps; and (ii) services exceeding 200 Amps. This results in the Basic Customer Charge for services exceeding 200 Amps to increase by approximately 0.9%, as opposed to 1.2%. The Minimum Monthly Charges for Rate 1.1 Domestic Service also reflect this approach.

[17] Newfoundland Power is proposing to maintain a $2.50/kW differential between winter and non-winter Demand Charges in Rate 2.1. Maintaining this differential will result in some components of Rate 2.1 increasing by an amount different than the proposed average increase of 1.2%.

[18] See the Company's *2016/2017 General Rate Application, Section 6: Customer Rates*, page 6-11, and Order No. P.U. 18 (2016).

Advocate and Hydro.[19]

Table 5-8 shows the monthly customer costs and existing Basic Customer Charges for unmetered, single phase and three phase service.[20]

Table 5-8:
General Service Rate 2.1
Customer Costs and Existing Basic Customer Charges

Service	Monthly Customer Cost ($)	Cost Differential ($)	Basic Customer Charge ($)	Charge Differential ($)
Unmetered	20.80		17.20	
		8.10		4.00
Single Phase	28.90		21.20	
		13.00		6.00
Three Phase	41.90		27.20	

The differences in Basic Customer Charges for unmetered, single phase and three phase service are intended to reflect the differences in the cost of providing each service. The cost of providing single phase service is $8.10 more than the cost of providing unmetered service. The cost of providing three phase service is $13.00 more than the cost of providing single phase service. Currently, the differences in Basic Customer Charges reflect approximately ½ of the

[19] Newfoundland Power submitted its *Rate Design Report* to the Board in January 2009 as part of the Company's *Retail Rate Review*. The report indicated that *"unmetered single phase services are less costly to serve than metered single phase services, and metered single phase services are less costly to serve than metered three phase services"* (page 60). The report also indicated that *"separate basic customer charges can be justified… for customers with unmetered services, single phase services and three phase services"* (page 83).

[20] The monthly customer cost was determined based on the results of the Company's *2016 Cost of Service Study*, provided in *Volume 2, Supporting Materials, Reports, Tab 4.* Monthly customer costs include costs related to meters, service wires, and customer billing.

cost differences in providing each service.[21]

Table 5-9 shows the monthly customer costs and proposed Basic Customer Charges for unmetered, single phase and three phase service.

Table 5-9:
General Service Rate 2.1
Customer Costs and Proposed Basic Customer Charges

Service	**Monthly Customer Cost ($)**	**Cost Differential ($)**	**Basic Customer Charge ($)**	**Charge Differential ($)**
Unmetered	20.80		12.50	
		8.10		8.00
Single Phase	28.90		20.50	
		13.00		12.00
Three Phase	41.90		32.50	

Newfoundland Power proposes to increase the differential between Basic Customer Charges for unmetered, single phase and three phase service.[22] The proposed Basic Customer Charges better reflect differences in the cost of providing each service.[23] This proposed change concludes the

[21] The Basic Customer Charge for single phase service is currently $4.00 more than the Basic Customer Charge for unmetered service. This represents approximately 49% of the cost difference in providing these services ($4.00 / $8.10 = 0.49, or 49%). The Basic Customer Charge for three phase service is currently $6.00 more than the Basic Customer Charge for single phase service. This represents approximately 46% of the cost difference in providing these services ($6.00 / $13.00 = 0.46, or 46%).

[22] Order No. P.U. 18 (2016) approved the introduction of separate customer charges in General Service Rate 2.1 for customers that have: (i) unmetered service; (ii) single phase service; and (iii) three phase service. In its *2016/2017 General Rate Application*, Newfoundland Power noted the initial change in Basic Customer Charges was less than the total indicated cost differential to limit customer impacts resulting from the changes (see the Company's *2016/2017 General Rate Application, Section 6: Customer Rates*, page 6-11).

[23] The Basic Customer Charge for single phase service is proposed to be $8.00 more than the Basic Customer Charge for unmetered service. This represents approximately 99% of the cost difference in providing these services ($8.00 / $8.10 = 0.99, or 99%). The Basic Customer Charge for three phase service is proposed to be $12.00 more than the Basic Customer Charge for single phase service. This represents approximately 92% of the cost difference in providing these services ($12.00 / $13.00 = 0.92, or 92%).

Company's phase-in of separate Basic Customer Charges for General Service Rate 2.1.[24]

It is also proposed that the overall average revenue increase from Basic Customer Charges in General Service Rate 2.1 be subject to the overall Rate 2.1 Class increase to the extent possible.[25]

Rate 2.3 General Service (110 – 1000 kVA)

The Company is proposing an increase to customers served under General Service Rate 2.3 equal to the overall average increase of 1.2%.

It is proposed that, on average, the Basic Customer Charge, Energy Charge, Demand Charges and Maximum Monthly Charge be subject to the overall Rate 2.3 Class increase to the extent possible.[26]

Rate 2.4 General Service (1000 kVA and Over)

The Company is proposing an increase to customers served under General Service Rate 2.4 equal to the overall average increase of 1.2%.

It is proposed that the Basic Customer Charge, Energy Charges, Demand Charges and Maximum Monthly Charge be subject to the overall Rate 2.4 Class increase to the extent possible.[27]

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[24] This concludes implementation of the recommendations outlined in the *Retail Rate Review*. For a list of other recommendations, please see the response to Request for Information CA-NP-144, filed in relation to the Company's *2013/2014 General Rate Application.*

[25] The overall average increase of 1.2% is reflected in the Basic Customer Charges shown in Table 5-9, page 5-13.

[26] Newfoundland Power is proposing to maintain a $2.50/kW differential between winter and non-winter Demand Charges in Rate 2.3. Maintaining this differential will result in some components of Rate 2.3 increasing by an amount different than the proposed average increase of 1.2%.

[27] The Company is proposing to maintain a $2.50/kW differential between winter and non-winter Demand Charges in Rate 2.4. Maintaining this differential will result in some components of Rate 2.4 increasing by an amount different than the proposed average increase of 1.2%.

Rate 4.1 Street and Area Lighting Service

The Company is proposing an increase to Street and Area Lighting Service rates equal to the overall average increase of 1.2%.[28]

5.5 NET METERING SERVICE OPTION

Order No. P.U. 17 (2017) approved the introduction of the Net Metering Service Option, effective July 1, 2017.[29]

As of April 30, 2018, the Company has received 16 applications, with 12 approved for construction. One customer is currently being billed under the Net Metering Service Option.[30] This customer is a small general service customer and has a 10 kW wind turbine. The remaining 11 customers approved for construction are comprised of: (i) 7 domestic customers approved to install solar panels with capacity ranging from 7 kW to 10 kW; (ii) 2 domestic customers and 1 general service customer approved to install wind generation with capacity ranging from 5 kW to 20 kW; and (iii) 1 general service customer approved to install a combination of 10 kW of solar and 3 kW of wind generation.

The total generation capacity of the customer generation approved or in service is 119 kW.

[28] Street and Area Lighting rates will continue to be developed based on recovering embedded costs with the price of fixtures, poles and wiring varying in a manner reflective of differences in their fixed costs and variable operating costs. Street and Area Lighting rates and the Rate Stabilization Clause will no longer refer to mercury vapour lights as none remain in service.

[29] Newfoundland Power filed its first annual report on its Net Metering Service Option with the Board on March 28, 2018.

[30] The 1 customer availing of the Net Metering Service Option started to take service under the option in March 2018.

Newfoundland Power Inc.

Operating Costs by Function
2015 to 2020F
($000s)

	Function	**Actual 2015**	**Actual 2016**	**Actual 2017**	**Forecast 2018**	**Forecast 2019**	**Forecast 2020**
1	Distribution	8,903	9,369	10,748	9,876	10,077	10,274
2	Transmission	1,034	806	1,097	1,009	1,028	1,048
3	Substations	2,646	2,593	2,856	2,737	2,866	2,922
4	Power Produced	2,808	3,521	3,574	3,578	3,689	3,761
5	Administrative & Engineering Support	7,375	7,727	7,660	7,826	7,980	8,137
6	Telecommunications	1,409	1,316	1,305	1,330	1,355	1,380
7	Environment	238	269	256	262	267	272
8	Fleet Operations & Maintenance	1,778	1,799	1,856	1,902	1,938	1,974
9							
10	**Electricity Supply**	**26,191**	**27,400**	**29,352**	**28,520**	**29,200**	**29,768**
11							
12	Customer Service	8,843	8,830	7,990	7,841	8,189	8,164
13	Conservation	707	439	620	623	825	693
14	Uncollectible Bills	1,313	1,194	1,386	1,418	1,445	1,472
15							
16	**Customer Services**	**10,863**	**10,463**	**9,996**	**9,882**	**10,459**	**10,329**
17							
18	Information Systems	3,655	3,911	4,358	4,512	5,212	5,526
19	Financial Services	1,779	1,593	1,689	1,728	1,759	1,793
20	Corporate & Employee Services	13,852	13,262	12,959	14,295	14,686	14,824
21	Insurances	1,260	1,293	1,326	1,357	1,382	1,408
22							
23	**General**	**20,546**	**20,059**	**20,332**	**21,892**	**23,039**	**23,551**
24							
25	**Gross Operating Cost**	**57,600**	**57,922**	**59,680**	**60,294**	**62,698**	**63,648**

Newfoundland Power Inc.

Operating Costs by Breakdown
2015 to 2020F
($000s)

		Actual 2015	Actual 2016	Actual 2017	Forecast 2018	Forecast 2019	Forecast 2020
1	Regular and Standby	29,700	29,329	30,539	30,463	31,131	31,525
2	Temporary	1,832	1,825	1,836	1,868	2,343	2,348
3	Overtime	2,409	2,606	3,364	2,793	2,842	2,899
4	**Total Labour**	**33,941**	**33,760**	**35,739**	**35,124**	**36,316**	**36,772**
5							
6	Vehicle Expenses	1,786	1,797	1,854	1,897	1,933	1,969
7	Operating Materials	1,580	1,422	1,526	1,509	1,538	1,567
8	Inter-Company Charges	35	31	26	27	27	28
9	Plants, Subs, System Oper & Bldgs	2,367	2,770	2,796	2,860	2,915	2,970
10	Travel	1,014	1,132	1,195	1,114	1,135	1,156
11	Tools and Clothing Allowance	1,130	1,160	1,234	1,175	1,197	1,219
12	Miscellaneous	1,381	1,276	1,361	1,339	1,365	1,390
13	Taxes and Assessments	1,123	1,214	1,252	1,281	1,305	1,330
14	Uncollectible Bills	1,313	1,194	1,386	1,418	1,445	1,472
15	Insurance	1,260	1,293	1,326	1,357	1,382	1,408
16	Severance & Other Employee Costs	72	47	102	74	75	76
17	Education, Training, Employee Fees	297	268	329	298	304	309
18	Trustee and Directors' Fees	462	471	489	500	510	519
19	Other Company Fees	2,506	2,392	1,118	2,420	2,956	2,969
20	Stationery & Copying	230	266	214	219	223	227
21	Equipment Rental/Maintenance	746	838	806	825	840	856
22	Telecommunications	1,621	1,513	1,490	1,524	1,553	1,582
23	Postage	1,562	1,444	1,436	1,406	1,369	1,332
24	Advertising	353	455	451	461	470	479
25	Vegetation Management	1,766	1,820	2,099	1,895	1,931	1,967
26	Computing Equipment & Software	1,055	1,359	1,451	1,571	1,909	2,051
27	**Total Other**	**23,659**	**24,162**	**23,941**	**25,170**	**26,382**	**26,876**
28							
29	**Gross Operating Cost**	**57,600**	**57,922**	**59,680**	**60,294**	**62,698**	**63,648**

Newfoundland Power Inc.

Financial Performance
2015 to 2020E
Statements of Income
($000s)

		Actual			Forecast		
		2015	**2016**	**2017**	**2018**	**2019E**	**2020E**
1	Revenue from rates	639,631	661,381	661,884	658,466	655,841	657,459
2	Excess earnings	-	68	-	-	-	-
3	Transfers from (to) the RSA	7,414	4,856	3,797	(1,663)	(6,337)	(6,744)
4		647,045	666,305	665,681	656,803	649,504	650,715
5							
6	Purchased power expense	424,430	443,311	435,306	432,443	430,627	430,644
7	DMI account adjustments	-	-	(2,128)	-	-	-
8	Amortization of Weather Normalization Balance	(2,335)	-	-	-	-	-
9	Wholesale rate change flow-through	-	-	7,071	-	-	-
10		422,095	443,311	440,249	432,443	430,627	430,644
11							
12	Contribution	224,950	222,994	225,432	224,360	218,877	220,071
13							
14	Other revenue	5,206	5,234	6,283	6,380	5,584	5,375
15							
16	Other expenses:						
17	Operating expenses[1]	55,157	56,851	59,915	61,620	64,682	66,571
18	Employee future benefit costs	26,355	18,441	17,039	14,029	9,080	7,566
19	Deferred cost recoveries and amortizations	3,990	2,064	(1,032)	(1,032)	-	-
20	Depreciation	51,851	55,190	57,487	59,801	62,314	64,797
21	Finance charges	35,161	34,643	34,894	35,768	35,948	37,034
22		172,514	167,189	168,303	170,186	172,024	175,968
23							
24	Income before income taxes	57,642	61,039	63,412	60,554	52,437	49,478
25	Income taxes[1]	16,529	18,152	19,424	18,137	15,814	14,985
26							
27	Net income	41,113	42,887	43,988	42,417	36,623	34,493
28	Preferred dividends	556	555	555	552	552	552
29							
30	Earnings applicable to common shares[1]	40,557	42,332	43,433	41,865	36,071	33,941
31							
32	**Rate of Return and Credit Metrics**						
33	Rate of Return on Rate Base (%)	7.48	7.31	7.22	7.00	6.34	6.09
34	Regulated Return on Book Equity (%)	8.98	8.90	8.93	8.47	7.04	6.44
35	Interest Coverage (times)	2.3	2.4	2.5	2.4	2.2	2.0
36	CFO Pre-W/C + Interest / Interest (times)	3.8	4.0	4.0	4.0	3.7	3.7
37	CFO Pre-W/C / Debt (%)	17.5	18.0	17.8	17.3	15.8	15.4

[1] Shown after adjustment for non-regulated expenses.

Newfoundland Power Inc.

Financial Performance
2015 to 2020E
Statements of Retained Earnings
($000s)

		Actual			Forecast		
		2015	**2016**	**2017**	**2018**	**2019E**	**2020E**
1	Balance - Beginning	366,426	395,934	414,954	417,517	430,876	453,175
2	Net income for the period	39,314	40,508	41,526	40,132	34,483	32,272
3	Allocation of Part VI.1 tax	245	533	11	1,025	752	752
4		405,985	436,975	456,491	458,674	466,111	486,199
5							
6	Dividends						
7	Preference shares	556	555	555	552	552	552
8	Common shares	9,495	21,466	38,419	27,246	12,384	25,594
9		10,051	22,021	38,974	27,798	12,936	26,146
10	Balance - End of Period	395,934	414,954	417,517	430,876	453,175	460,053

Newfoundland Power Inc.

Financial Performance
2015 to 2020E
Balance Sheets
($000s)

	Actual			Forecast		
	2015	**2016**	**2017**	**2018**	**2019E**	**2020E**
Assets						
Current assets						
Accounts receivable	80,600	75,639	79,696	87,642	88,860	89,788
Income taxes receivable	9,105	-	68	-	-	-
Materials and supplies	1,435	1,419	1,465	1,499	1,527	1,556
Prepaid expenses	1,304	1,842	2,022	2,069	2,108	2,148
Regulatory assets	14,545	12,783	14,027	10,860	788	1,049
	106,989	91,683	97,278	102,070	93,283	94,541
Property, plant and equipment	1,038,108	1,082,095	1,118,644	1,154,017	1,190,603	1,227,804
Intangible assets	18,264	21,168	22,501	24,669	26,800	27,955
Regulatory assets	227,850	334,725	337,764	316,561	315,019	307,650
Defined benefit pension plans	102,964	9,164	11,206	19,338	26,153	33,640
Other assets	1,301	1,488	1,631	1,622	1,613	1,614
	1,495,476	1,540,323	1,589,024	1,618,277	1,653,471	1,693,204
Liabilities and shareholders' equity						
Current liabilities						
Short-term borrowings	2,404	2,349	3,575	-	-	-
Accounts payable and accrued charges	80,719	78,535	83,775	79,045	77,571	77,462
Interest payable	7,246	6,623	6,785	6,646	6,536	6,606
Income taxes payable	-	495	-	-	-	-
Defined benefit pension plans	239	233	1,055	252	225	218
Other post employment benefits	2,971	3,388	3,640	3,703	3,709	4,165
Regulatory liabilities	-	1,032	1,032	-	-	-
Current instalments of long-term debt	53,750	66,350	18,600	52,899	63,759	79,318
	147,329	159,005	118,462	142,545	151,800	167,769
Regulatory liabilities	139,768	144,451	156,229	160,471	168,499	177,436
Defined benefit pension plans	6,643	5,859	5,263	-	-	-
Other post employment benefits	83,565	88,570	78,151	79,411	80,805	81,892
Other liabilities	1,286	786	1,066	1,066	1,066	1,066
Deferred income taxes	128,322	139,750	157,935	155,920	156,550	155,922
Long-term debt	513,369	507,697	575,163	568,750	562,337	569,828
Shareholders' equity						
Common shares	70,321	70,321	70,321	70,321	70,321	70,321
Preference shares	8,939	8,930	8,917	8,917	8,917	8,917
Retained earnings	395,934	414,954	417,517	430,876	453,175	460,053
	475,194	494,205	496,755	510,114	532,413	539,291
	1,495,476	1,540,323	1,589,024	1,618,277	1,653,471	1,693,204

Newfoundland Power Inc.

Financial Performance
2015 to 2020E
Statements of Cash Flows
($000s)

		Actual			Forecast		
		2015	**2016**	**2017**	**2018**	**2019E**	**2020E**
1	**Cash From (Used In) Operating Activities**						
2	Net Earnings	39,314	40,508	41,526	40,132	34,483	32,272
3							
4	**Items Not Affecting Cash:**						
5	Amortization of property, plant and equipment	54,172	57,673	59,885	62,212	64,614	67,011
6	Amortization of intangible assets and other	2,790	3,021	3,320	3,476	3,806	4,128
7	Change in long-term regulatory assets and liabilities	(1,649)	2,334	525	8,165	4,467	8,600
8	Deferred income taxes	(698)	(353)	2,291	(2,013)	630	(628)
9	Employee future benefits	4,832	4,170	3,025	(1,654)	(6,374)	(8,194)
10	Other	(318)	(59)	(460)	581	293	284
11		98,443	107,294	110,112	110,899	101,919	103,473
12							
13	Change in non-cash working capital	4,617	11,824	(144)	(12,744)	4,823	(287)
14		103,060	119,118	109,968	98,155	106,742	103,186
15							
16	**Investing Activities**						
17	Capital expenditures	(111,236)	(101,257)	(91,774)	(92,534)	(95,825)	(98,308)
18	Intangible asset expenditures	(4,748)	(5,703)	(4,422)	(5,457)	(5,750)	(5,092)
19	Contributions from customers and security deposits	2,508	3,908	4,367	3,500	3,500	3,500
20	Other	551	(630)	125	9	9	(1)
21		(112,925)	(103,682)	(91,704)	(94,482)	(98,066)	(99,901)
22							
23	**Financing Activities**						
24	Change in short-term borrowings	(1,439)	(55)	1,226	(3,574)	-	-
25	Net proceeds (repayment) of committed credit facility	(47,000)	43,000	(48,500)	34,299	10,860	(14,789)
26	Proceeds from long-term debt	75,000	-	75,000	-	-	75,000
27	Repayment of long-term debt	(6,250)	(36,250)	(6,600)	(6,600)	(6,600)	(36,950)
28	Proceeds from related party loan	35,500	-	-	-	-	-
29	Repayment of related party loan	(35,500)	-	-	-	-	-
30	Payment of debt financing costs	(386)	(101)	(403)	-	-	(400)
31	Redemption of preference shares	(9)	(9)	(13)	-	-	-
32	Dividends				-	-	-
33	Preference shares	(556)	(555)	(555)	(552)	(552)	(552)
34	Common shares	(9,495)	(21,466)	(38,419)	(27,246)	(12,384)	(25,594)
35		9,865	(15,436)	(18,264)	(3,673)	(8,676)	(3,285)
36							
37	**Change in Cash**	-	-	-	-	-	-
38	**Cash (Bank Indebtedness), Beginning of Year**	-	-	-	-	-	-
39	**Cash (Bank Indebtedness), End of Year**	-	-	-	-	-	-

Newfoundland Power Inc.

Financial Performance
2015 to 2020E
Average Rate Base[1]
($000s)

	Actual			Forecast		
	2015	**2016**	**2017**	**2018**	**2019E**	**2020E**
Plant Investment	937,986	986,570	1,025,659	1,057,788	1,091,011	1,123,671
Additions to Rate Base						
Defined Benefit Pension Costs	101,384	96,802	93,396	90,829	91,210	95,350
Deferred Credit Facility Costs	64	75	102	96	68	39
Cost Recovery Deferral - Seasonal Rates	59	25	-	-	-	-
Cost Recovery Deferral - Hearing Costs	161	341	512	171	-	-
Cost Recovery Deferral - Reg. Amortizations	554	-	-	-	-	-
Cost Recovery Deferral - 2012 Cost of Capital	294	-	-	-	-	-
Cost Recovery Deferral - 2013 Revenue Shortfall	563	-	-	-	-	-
Cost Recovery Deferral - Conservation	6,200	9,384	12,710	15,164	16,993	17,219
Weather Normalization Reserve	1,386	3,066	3,246	2,250	(136)	-
Demand Management Incentive Account	(223)	-	745	745	-	-
Customer Finance Programs	1,174	1,276	1,419	1,513	1,545	1,575
	111,616	110,969	112,130	110,768	109,680	114,183
Deductions from Rate Base						
Other Post Employee Benefits	35,822	42,646	49,334	54,341	57,846	61,415
Customer Security Deposits	974	1,036	926	1,066	1,066	1,066
Accrued Pension Obligation	4,795	5,120	5,430	5,304	5,174	5,469
Accumulated Deferred Income Taxes	1,899	1,727	3,051	4,761	6,977	9,808
Excess Earnings Account	49	25	-	-	-	-
2016 Cost Recovery Deferral	-	723	1,084	362	-	-
	43,539	51,277	59,825	65,834	71,063	77,758
Average Rate Base Before Allowances	1,006,063	1,046,262	1,077,964	1,102,722	1,129,628	1,160,096
Cash Working Capital Allowance	6,739	8,318	8,153	8,251	8,212	8,169
Materials and Supplies Allowance	6,280	6,464	6,137	5,821	5,925	6,037
Average Rate Base at Year End	1,019,082	1,061,044	1,092,254	1,116,794	1,143,765	1,174,302

[1] All amounts shown are averages.

Newfoundland Power Inc.

Financial Performance
2015 to 2020E
Weighted Average Cost of Capital
($000s)

		Actual			Forecast		
		2015	**2016**	**2017**	**2018**	**2019E**	**2020E**
1	**Average Capitalization**						
2	Debt	559,350	572,841	586,726	609,381	623,801	637,582
3	Preference Shares	8,944	8,935	8,924	8,917	8,917	8,917
4	Common Equity	451,501	475,765	486,557	494,517	512,346	526,936
5		1,019,795	1,057,541	1,082,207	1,112,815	1,145,064	1,173,435
6	**Average Capital Structure (%)**						
7	Debt	54.85	54.17	54.22	54.76	54.48	54.33
8	Preference Shares	0.88	0.84	0.82	0.80	0.78	0.76
9	Common Equity	44.27	44.99	44.96	44.44	44.74	44.91
10		100.00	100.00	100.00	100.00	100.00	100.00
11							
12							
13	**Cost of Capital (%)**						
14	Debt[1]	6.28	6.05	5.95	5.87	5.76	5.81
15	Preference Shares	6.22	6.21	6.22	6.19	6.19	6.19
16	Common Equity	8.98	8.90	8.93	8.47	7.04	6.44
17							
18							
19	**Weighted Average Cost of Capital (%)**						
20	Debt	3.44	3.28	3.22	3.21	3.14	3.15
21	Preference Shares	0.05	0.05	0.05	0.05	0.05	0.05
22	Common Equity	3.98	4.00	4.01	3.76	3.15	2.89
23		7.47	7.33	7.28	7.02	6.34	6.09

[1] Cost of debt is shown net of AFUDC. This is consistent with the cost of debt used in the calculation of return on rate base. For regulatory reporting purposes, the embedded cost of debt shown in Return 25 of the 2015 to 2017 Annual Reports to the Board can be reconciled to the reported cost of debt above as follows:

	2015	2016	2017
Cost of Debt (Line 14) (%)	6.28	6.05	5.95
AFUDC (%)	0.22	0.22	0.17
Cost of Debt - Return 25 (%)	6.50	6.27	6.12

Newfoundland Power Inc.

Financial Performance
2015 to 2020E
Rate of Return on Rate Base
($000s)

		Actual			Forecast		
		2015	**2016**	**2017**	**2018**	**2019E**	**2020E**
1	Regulated Return on Equity	40,557	42,332	43,433	41,865	36,071	33,941
2	Return on Preferred Equity	556	555	555	552	552	552
3		41,113	42,887	43,988	42,417	36,623	34,493
4							
5	Finance Charges						
6	Interest on Long-term Debt	35,020	34,846	35,013	35,789	35,374	37,080
7	Other Interest	1,119	867	659	715	1,354	755
8	Amortization of Bond Issue Expenses	242	223	234	232	224	219
9	AFUDC	(1,240)	(1,304)	(1,025)	(984)	(1,021)	(1,039)
10		35,141	34,632	34,881	35,752	35,931	37,015
11							
12	Return on Rate Base	76,254	77,519	78,869	78,169	72,554	71,508
13							
14	Average Rate Base	1,019,082	1,061,044	1,092,254	1,116,794	1,143,765	1,174,302
15							
16	Rate of Return on Rate Base (%)	7.48	7.31	7.22	7.00	6.34	6.09

Newfoundland Power Inc.

Financial Performance
2015 to 2020E
Inputs and Assumptions

Energy Forecasts: Energy forecasts are based on economic indicators taken from the Conference Board of Canada, Provincial Outlook, Long Term Economic Forecast, dated January 19, 2018.

Revenue Forecast: The revenue forecast is based on the Customer, Energy and Demand forecast dated April 6, 2018.

Forecast revenues for 2015 through 2018 reflects: (i) recovery through the RSA of amounts associated with the Energy Supply Cost Variance Adjustment Clause; (ii) recovery through the RSA of amounts associated with variances in employee future benefit costs; (iii) recovery through the RSA of amounts associated with the July 1, 2017 Hydro supply cost rate increase; (iv) recovery through the RSA of amounts associated with the Weather Normalization reserve; and (iv) recovery through the RSA of certain costs related to the implementation of the CDM program portfolio; all of which were approved by the Board in Order Nos. P.U. 32 (2007), P.U. 43 (2009), P.U. 31 (2010), P.U. 8 (2011), P.U. 13 (2013), P.U. 18 (2015) and P.U. 23 (2017).

Purchased Power Expense: Purchased power expense reflects Newfoundland and Labrador Hydro's rates approved by the Board and the Customer, Energy and Demand Forecast dated April 6, 2018.

Purchased power expense reflects the operation of the Demand Management Incentive Account approved by the Board in Order No. P.U. 32 (2007). This mechanism provides for recovery of demand costs that are in excess of unit cost demand costs included in the most recent test year.

Purchased power expense reflects the operation of the wholesale rate change flow-through account resulting from the implementation of the Revised Utiliy Base Rate as approved in Order No. P.U. 23 (2017).

Employee Future Benefit Costs: Pension funding is based on the actuarial valuation dated as at December 31, 2017.

Pension expense and OPEBs expense discount rate is 3.60% for 2018 through 2020.

Forecast return on pension assets is assumed to be 5.25% for 2018 through 2020.

Cost Recovery Deferrals: The 2018 to 2020 forecasts include the deferred recovery over a 7-year period of certain conservation program costs as reflected in the Application.

The 2018 forecast includes the deferred recovery over a 30-month period of $0.9 million in external costs related to the *2016/2017 General Rate Application.*

The forecast also includes the amortization, over a 30-month period, of a $2.6 revenue surplus related to a July 1, 2016 rate implementation date.

Depreciation Rates: Depreciation rates are based on the *2014 Depreciation Study* .

Depreciation costs for 2016 through 2020 include an approximately $0.6 million annual reserve variance adjustment resulting from the *2014 Depreciation Study* .

Newfoundland Power Inc.

Financial Performance
2015 to 2020E
Inputs and Assumptions

Operating Costs: The operating forecast for 2018 reflects the most recent management estimates. Operating forecasts for 2019 and 2020 reflect projected labour rate increases of 1.75% and 2.00% per year, respectively, and non labour increases based upon the GDP deflator.

Capital Expenditure: Capital Expenditures for 2018 through 2020 are based on the *2018 Capital Budget Application* adjusted for known carryovers in 2018.

Short-Term Interest Rates: Average short-term interest rates are assumed to be 2.60% for 2018, 3.27% for 2019 and 3.60% for 2020.

Long-Term Debt: A $75.0 million long-term debt issue is forecast to be completed in April 2020. The debt is forecast for 30 years at a coupon rate of 5.25%. Debt repayments will be in accordance with the normal sinking fund provisions for existing outstanding debt.

Dividends: Common dividend payouts are forecast based on maintaining a target common equity component near 45%.

Income Tax: Income tax expense reflects a statutory income tax rate of 30% for 2018 through 2020.

Credit Rating Reports:
Moody's and DBRS

MOODY'S
INVESTORS SERVICE

CREDIT OPINION
31 January 2018

Update

Rate this Research

RATINGS

Newfoundland Power Inc.

Domicile	St. John's, Newfoundland, Canada
Long Term Rating	Baa1
Type	LT Issuer Rating - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

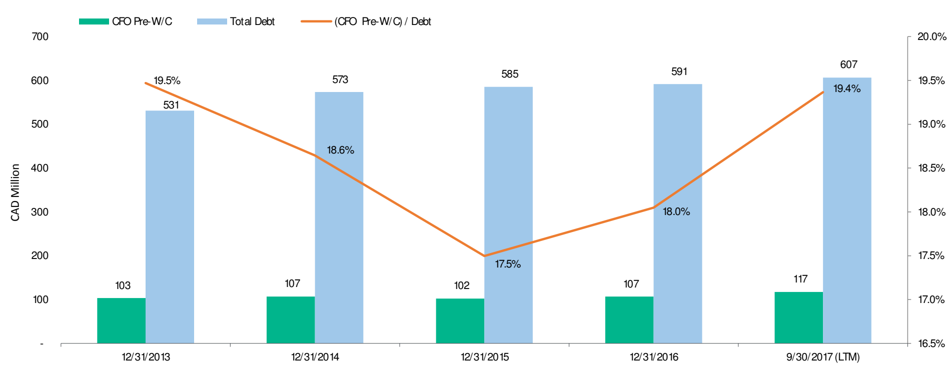
Newfoundland Power Inc.

Update to credit analysis

Summary

Newfoundland Power Inc.'s (NPI, Baa1 stable) credit profile reflects the company's low business risk as a vertically integrated cost-of-service regulated utility with no unregulated business activities. Approximately 93% of NPI's power requirements are purchased from provincially owned Newfoundland & Labrador Hydro (Hydro), the cost of which is passed through to ratepayers. NPI's allowed Return on Equity (ROE) is 8.50% for 2016-2018, and we view the Newfoundland and Labrador Board of Commissioners of Public Utilities (PUB) as one of the more supportive regulators in Canada because regulatory decisions are timely and balanced, deferral accounts reduce the risks from factors beyond management's control and NPI's 45% equity capital is among the highest authorized levels in Canada. The credit profile is constrained by the risk of future cost recovery associated with the Province of Newfoundland and Labrador's sizeable Muskrat Falls hydroelectric project. This politically sensitive project is large relative to the provincial economy and is expected to place considerable upward pressure on the future electricity rates of NPI, a credit negative. NPI's senior secured FMB reflects the first mortgage security over NPI's property, plant and equipment and floating charge on all other assets.

Exhibit 1
Historical CFO Pre W/C, Total Debt and CFO Pre W/C to Debt



Source: Moody's Financial Metrics

Credit strengths

» Low risk regulated utility, primarily a T&D, with 93% purchased power from provincial generators

» Supportive regulatory environment

» Stable cash flow metrics with CFO pre-W/C to debt in the mid to high teens

Credit challenges

» Upward pressure on rates due to the Muskrat Falls project

» Increased risks of timely cost recovery upon completion Muskrat Falls expected in 2020

Rating outlook

The stable rating outlook reflects the PUB's regulation of NPI which we consider credit supportive. We expect the regulatory environment to remain supportive to credit quality, with a suite of timely recovery mechanisms, along with our expectation that relatively stable cash flow generation and the capital structure of NPI will generate sustained CFO pre-WC to debt in the 17-20% range.

Factors that could lead to an upgrade

NPI's rating would likely be upgraded if CFO pre-WC to debt is forecast to be sustained above 17%. However, an upgrade of NPI's rating is unlikely without further clarity on the timing and size of the increases in electricity rates in relation to the Muskrat Falls hydroelectric project.

Factors that could lead to a downgrade

We consider a downward revision in NPI's rating to be unlikely in the near term. However, NPI's rating would likely be downgraded if we perceived a meaningful reduction in the level of regulatory support combined with a sustained deterioration in NPI's financial metrics such as CFO pre-WC to debt falling into the low teens.

Key indicators

Exhibit 2

Newfoundland Power Inc.

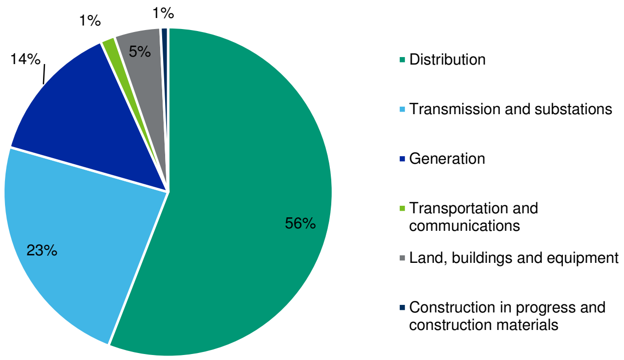
	12/31/2013	12/31/2014	12/31/2015	12/31/2016	9/30/2017(L)
CFO pre-WC + Interest / Interest	3.7x	3.9x	3.8x	4.0x	4.3x
CFO pre-WC / Debt	19.5%	18.6%	17.5%	18.0%	19.4%
CFO pre-WC – Dividends / Debt	15.2%	14.6%	15.9%	14.4%	13.2%
Debt / Capitalization	49.7%	50.5%	49.6%	48.6%	49.3%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics

Profile

Headquartered in St. John's, Newfoundland, NPI is a vertically integrated electric utility serving a customer base of over 265,000 customers. NPI operates under cost of service regulation and is regulated by the PUB under the Public Utilities Act (the Act). NPI purchases the majority of its power from Newfoundland and Labrador Hydro (not rated). NPI's installed generating capacity is 139 MW, including 97 MW of hydro. NPI is a wholly-owned subsidiary of Fortis Inc. (FTS: Baa3 stable), which is primarily a diversified electric and gas utility holding company also based in St. John's.

Exhibit 3
2016 Net Property, Plant and Equipment by segmentNewfoundland Power Inc.



Source: NPI's 2016 AR

Detailed credit considerations

LOW-RISK BUSINESS MODEL

NPI's credit profile reflects the company's low business risk as a cost of service regulated utility. NPI owns and operates a vertically integrated electric utility located on the island portion of the province of Newfoundland and Labrador and dominates that market, which is geographically isolated and effectively protected from potential competition. NPI serves roughly 90% of the province's electricity customers. The market is mature and NPI's electricity sales have tended to be relatively stable. Historically, growth has not taxed NPI either operationally or financially due to relatively timely recovery of capital and operating costs.

Although NPI is vertically integrated, NPI's owned generation assets are regulated and represent only 14% of NPI's net property, plant and equipment at year-end 2016. Accordingly, we consider the business risk of NPI to be lower than that of a typical vertically integrated utility, which is often exposed to commodity price and volume risks or the operational, financial and environmental risks associated with electricity generation. However, NPI faces uncertainties due to the timing and size of expected rate increases in association with the Muskrat Falls hydroelectric project. The total cost (including financing) of Muskrat Falls and transmission in NewFoundland and Labrador has increased to about C$12.7 billion and the date of full power has been pushed back to 2020 as the project has struggled with execution risks.

SUPPORTIVE REGULATORY AND BUSINESS ENVIRONMENT

NPI's operations benefit from a well-developed regulatory framework and business environments that we consider credit supportive. We consider the PUB's regulation of NPI to be credit supportive primarily because of a track record of reasonably timely and balanced decisions that enable NPI to generate stable and predictable cash flow and earn its allowed ROE which has not been directly subject to political interference. NPI has access to courts for disputes with the PUB.

The PUB's review and approval of NPI's capital spending plans and long-term debt issuances significantly reduce the risk of cost disallowances and support NPI's ability to fully recover costs on a timely basis. NPI submits a proposed capital plan for PUB approval annually before the next fiscal year. Furthermore, NPI is required to obtain PUB pre-approval for the issuance of any First Mortgage Bonds (FMB) or the incurrence of credit facilities with maturities exceeding one year, which we see as credit positives.

Several other cost recovery mechanisms reduce NPI's exposure to unexpected costs due to variations in purchased power costs, weather and pension and other post-employment benefit (OPEB) costs. While NPI foregoes some upside potential, the stability and predictability of its cash flows are increased. For example, the Rate Stabilization Account (RSA) facilitates timely recovery of purchased power costs in excess of those forecasted for rate-making purposes. This is particularly important since the marginal cost of power that NPI obtains from Hydro exceeds the average supply costs embedded in customer rates. The RSA provides for the amortization of the under or over collection over a 12 month period. Other mechanisms include the Weather Normalization Account, Conservation and Demand Management Deferral and the Demand Management Incentive Account (which limits NPI's exposure to variation in purchased power costs due to demand to 1% of demand costs reflected in the test year for rate-making purposes).

NPI is allowed to file a rate application based on a forward test year and forecast rate base. We view these mechanisms positively because they reduce revenue lag associated with large capital projects. NPI's allowed ROE of 8.5% for 2016-2018 has been lowered slightly from the previous 8.8% in the period 2013-2015. While the ROE remains relatively low, it is mitigated by one of the highest deemed equity levels in Canada at 45%.

Exhibit 4

Historical Approved ROE, Approved Equity thickness and Rate Base Newfoundland Power Inc.

	2013	2014	2015	2016	2017
Approved Return on Equity (ROE)	8.8%	8.8%	8.8%	8.5%	8.5%
Approved Equity thickness	45%	45%	45%	45%	45%
Midyear Rate base, CAD billion	0.9	1.0	1.0	1.1	1.1

Source: NPI's financial statements, Fortis Inc's presentations

We expect the company to continue to generate predictable cash flow, a key credit strength. Driving this stability, the company's net income is a function of its allowed return on equity, its deemed capital structure (equity thickness) and rate base. The other large component of it's predictable cash flow is depreciation and amortization. NPI's comparatively strong financial performance as suggested by CFO pre-W/C to debt of around 18% in 2014-2016 and 19% on an LTM basis as of September 30, 2017, reflects changes in regulated assets and liabilities and pension liability reductions. Despite the reduction in the allowed ROE we expect NPI to continue to achieve sustainable CFO pre-W/C to debt consistent with our expectations and the current rating.

Exhibit 5

Historical CFO Pre-W/C BreakdownNewfoundland Power Inc.

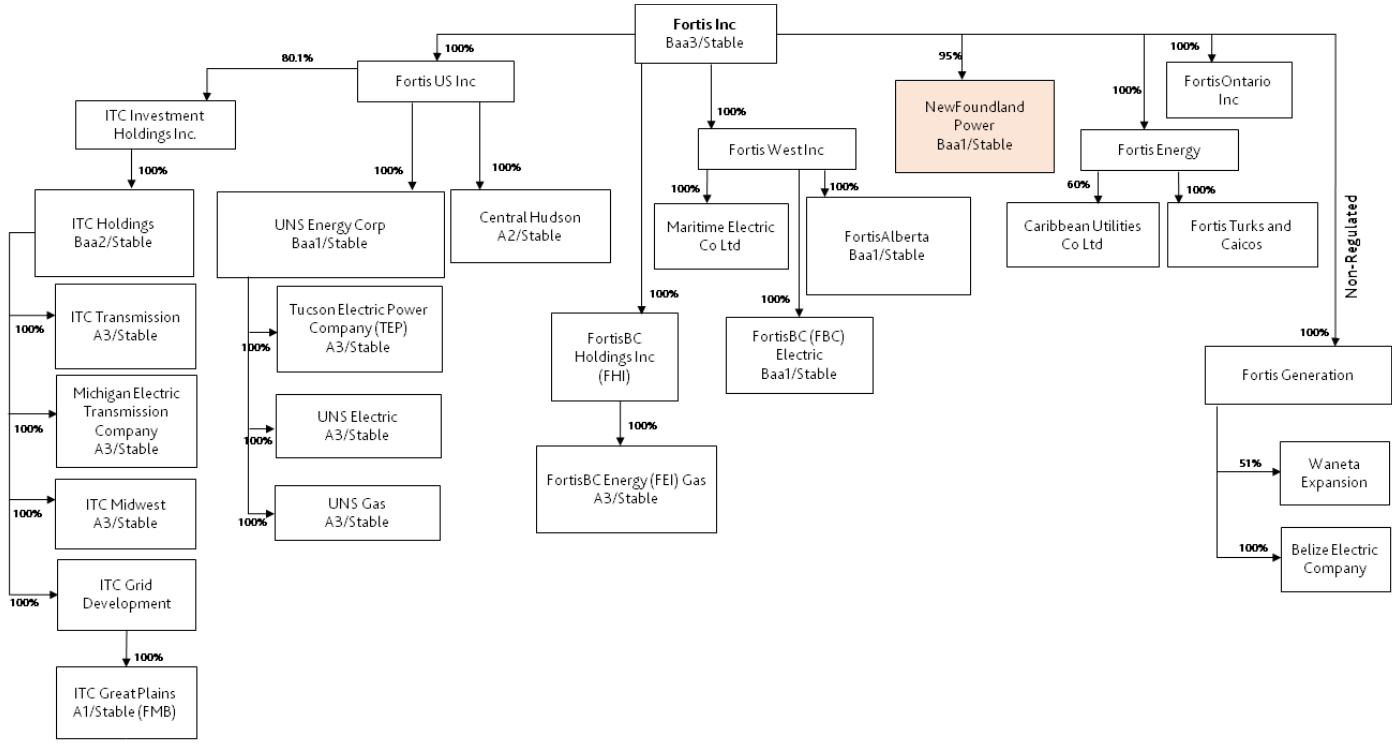
(in CN$ Millions)	FYE Dec-12	FYE Dec-13	FYE Dec-14	FYE Dec-15	FYE Dec-16	LTM Ending Sep-17
As Adjusted						
Net Income	**36.6**	**49.4**	**37.3**	**38.8**	**40.0**	**41.2**
Depreciation	44.7	48.8	51.4	54.2	57.7	59.4
Amortization of Investments	3.0	2.8	2.8	2.8	3.0	3.2
Deferred income taxes and itc	2.4	(0.9)	(0.2)	(0.7)	(0.4)	0.1
Other	(3.5)	(13.1)	(1.4)	4.5	4.1	3.9
Funds from Operations	**83.2**	**87.0**	**89.7**	**99.5**	**104.4**	**107.8**
Changes in Other Oper. Assets & Liabilities - LT	8.9	16.3	17.2	2.9	2.3	9.6
CFO Pre-W/C	**92.2**	**103.3**	**106.9**	**102.4**	**106.7**	**117.5**

All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months.
Source: Moody's Financial Metrics

NPI IS INDEPENDENT OF FORTIS INC.

While NPI is one of a number of utility operating companies owned by FTS, we consider NPI, like sister companies FortisAlberta Inc. (FAB: Baa1 stable), FortisBC Inc. (FBC: Baa1 stable) and FortisBC Energy Inc. (FEI: A3 stable), to be operationally and financially independent from Fortis, a credit positive. Fortis has consistently demonstrated good management and support of its subsidiaries and we view NPI's access to the executive and strategic support of Fortis to be a credit positive. While we don't expect it, if required, and consistent with Fortis precedent, we have assumed that Fortis Inc. would provide extraordinary support to NPI, provided that the parent had the economic incentive and sufficient resources to do so. Fortis is a more highly leveraged holding company and it is ultimately reliant on distributions from its subsidiaries to finance its obligations. The weaker credit quality of Fortis does not constrain the ratings of NPI.

Exhibit 6
Fortis Inc's Organizational Structure



Source: Fortis Inc

Liquidity analysis

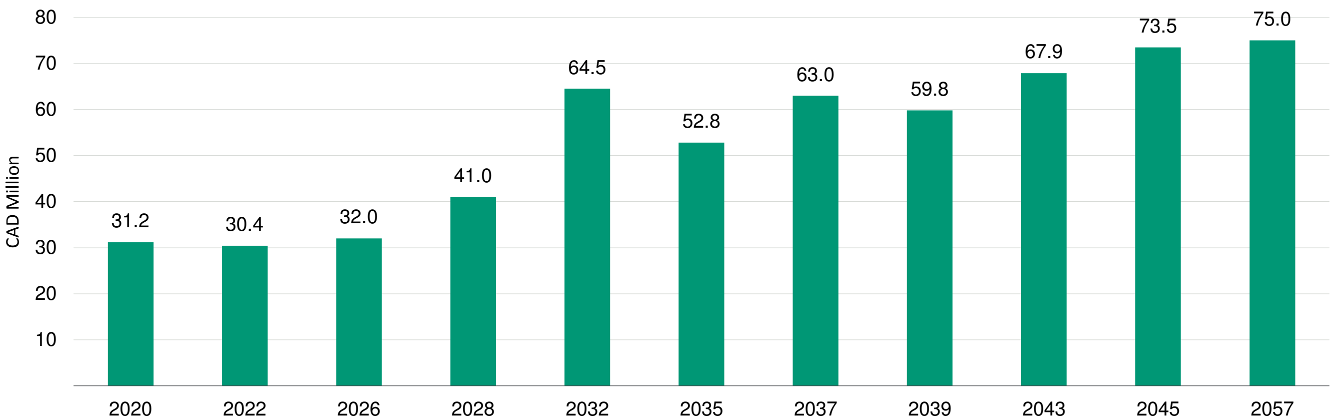
NPI's liquidity arrangements are considered adequate in the context of its relatively stable cash flow and funding requirements.

NPI plans to spend about $84 million on capital expenditures in 2018 and pay dividends in amounts commensurate with maintaining the 45% deemed equity layer. With estimated cash flow from operations to be about $110-120 million, we expect that any modest free cash flow shortfall is funded through NPI's bank credit facilities and adjustments to dividends paid which we expect to be about $30 million in 2018.

The company's core liquidity facility is a $100 million committed revolving credit facility that matures in August 2022. While the credit agreement contains a covenant that NPI maintain its debt to capitalization ratio at or below 65%, it does not include a material adverse change (MAC) clause or representation and warranty declaration prior to drawdown. There was no outstanding balance under the committed facility at 30 September 2017. The company's next debt maturity is in October 2020.

Exhibit 7

Long-term Debt Maturity as of 30 September 2017Newfoundland Power Inc.



NPI's debt consists of first mortgage sinking fund bonds.
Source: NPI's financial statements, FactSet

Structural considerations

NPI's senior secured FMB reflects the first mortgage security over NPI's property, plant and equipment and floating charge on all other assets. The A2 rating for these bonds is consistent with the two notch differential between most senior secured debt ratings and senior unsecured debt ratings of investment-grade regulated utilities operating in North America. The differential is based on our analysis of the history of regulated utility defaults, which indicates that regulated utilities have experienced lower loss given default rates (higher recovery rates) than non-financial, non-utility corporate issuers.

Rating methodology and scorecard factors

Exhibit 8

Rating Factors

Newfoundland Power Inc.

Regulated Electric and Gas Utilities Industry Grid [1][2]	Current LTM 9/30/2017		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns	Baa	Baa	Baa	Baa
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	4.1x	Baa	3.8x - 4.2x	Baa
b) CFO pre-WC / Debt (3 Year Avg)	18.8%	Baa	17% - 20%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	14.9%	Baa	13% - 15%	Baa
d) Debt / Capitalization (3 Year Avg)	49.4%	Baa	49% - 51%	Baa
Rating:				
Grid-Indicated Rating Before Notching Adjustment		Baa1		Baa1
HoldCo Structural Subordination Notching			0	0
a) Indicated Rating from Grid		Baa1		Baa1
b) Actual Rating Assigned		Baa1		Baa1

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 9/30/2017(L);
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics™

Appendix

Exhibit 9

Peer Comparison Table

Newfoundland Power Inc.

	Newfoundland Power Inc. Baa1 Stable			FortisAlberta Inc. Baa1 Stable			Hydro One Inc. A3 Negative		
(in CN$ Millions)	FYE Dec-15	FYE Dec-16	LTM Sep-17	FYE Dec-15	FYE Dec-16	LTM Sep-17	FYE Dec-15	FYE Dec-16	LTM Sep-17
Revenue	$653	$672	$676	$563	$572	$591	$6,529	$6,502	$6,122
CFO Pre-W/C	$102	$107	$117	$310	$299	$296	$1,382	$1,528	$1,596
Total Debt	$585	$591	$607	$1,772	$1,927	$2,053	$11,184	$12,114	$12,527
(CFO Pre-W/C) / Debt	17.5%	18.0%	19.4%	17.5%	15.5%	14.4%	12.4%	12.6%	12.7%
(CFO Pre-W/C - Dividends) / Debt	15.9%	14.4%	13.2%	14.1%	8.3%	7.7%	4.4%	7.5%	8.3%
(CFO Pre-W/C + Interest) / Interest Expense	3.8x	4.0x	4.3x	4.9x	4.5x	4.2x	4.0x	4.3x	4.3x
Debt / Book Capitalization	49.6%	48.6%	49.3%	54.3%	55.7%	56.0%	52.8%	55.0%	55.5%

All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months. RUR* = Ratings under Review, where UPG = for upgrade and DNG = for downgrade.
Source: Moody's Financial Metrics™

Exhibit 10

Moody's adjusted Debt breakdown

Newfoundland Power Inc.

(in CN$ Millions)	FYE Dec-12	FYE Dec-13	FYE Dec-14	FYE Dec-15	FYE Dec-16	LTM Ending Sep-17
As Reported Debt	**493.2**	**515.2**	**549.4**	**569.5**	**576.4**	**588.7**
Pensions	44.0	6.6	15.0	6.9	6.1	6.1
Hybrid Securities	9.1	9.0	8.9	8.9	8.9	8.9
Moody's-Adjusted Debt	**546.2**	**530.8**	**573.3**	**585.3**	**591.4**	**606.5**

All figures are calculated using Moody's estimates and standard adjustments.
Source: Moody's Financial Metrics™

Exhibit 11

Moody's-Adjusted EBITDA Breakdown

Newfoundland Power Inc.

(in CN$ Millions)	FYE Dec-12	FYE Dec-13	FYE Dec-14	FYE Dec-15	FYE Dec-16	LTM Ending Sep-17
As Reported EBITDA	**128.8**	**134.7**	**139.2**	**142.9**	**148.3**	**151.9**
Pensions	6.9	8.6	7.1	10.0	3.2	2.3
Moody's-Adjusted EBITDA	**135.7**	**143.3**	**146.3**	**152.9**	**151.5**	**154.1**

All figures are calculated using Moody's estimates and standard adjustments.
Source: Moody's Financial Metrics™

Exhibit 12

Cash Flow Adjusted Financial Data

Newfoundland Power Inc.

(in CN$ Millions)	2012	2013	2014	2015	2016	LTM (09/17)
As Adjusted						
EBITDA	**136**	**143**	**146**	**153**	**151**	**154**
FFO	**83**	**87**	**90**	**100**	**104**	**108**
- Div	11	23	23	9	21	37
RCF	**72**	**64**	**67**	**90**	**83**	**71**
FFO	**83**	**87**	**90**	**100**	**104**	**108**
+/- ΔWC	(8)	(4)	5	5	12	(11)
+/- Other	9	16	17	3	2	10
CFO	**84**	**100**	**112**	**107**	**119**	**107**
- Div	11	23	23	9	21	37
- Capex	85	92	117	116	107	91
FCF	**(12)**	**(15)**	**(28)**	**(18)**	**(10)**	**(22)**

All figures are calculated using Moody's estimates and standard adjustments.
Source: Moody's Financial Metrics™

Ratings

Exhibit 13

Category	Moody's Rating
NEWFOUNDLAND POWER INC.	
Outlook	Stable
Issuer Rating -Dom Curr	Baa1
First Mortgage Bonds -Dom Curr	A2
PARENT: FORTIS INC.	
Outlook	Stable
Issuer Rating -Dom Curr	Baa3
Senior Unsecured	Baa3

Source: Moody's Investors Service

REPORT NUMBER 1108365

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

Rating Report

Newfoundland Power Inc.

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Insight beyond the rating.

Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
First Mortgage Bonds	A	Confirmed	Stable
Preferred Shares - cumulative, redeemable	Pfd-2	Confirmed	Stable

Rating Update

On August 29, 2017, DBRS Limited (DBRS) confirmed the Issuer Rating and First Mortgage Bonds rating of Newfoundland Power Inc. (Newfoundland Power or the Company) at "A" and the Preferred Shares – cumulative, redeemable rating at Pfd-2. All trends remain Stable. The confirmation is based on the continued stability of the Company's regulated electricity business, which consists primarily of electricity distribution, and the solid financial risk profile.

Newfoundland Power's business risk profile remains supported by the Company's stable regulated integrated electricity business, which operates under a reasonable regulatory regime by the Board of Commissioners of Public Utilities (PUB). There have been no material regulatory changes since the last rating review in August 2016; the most recent General Rate Application (GRA) decision released in June 2016 established a deemed equity component of 45% and an allowed return on equity (ROE) of 8.5% until 2018. Newfoundland Power also continues to benefit from the use of multiple regulatory deferral accounts, such as the Rate Stabilization Account (RSA) and the Weather Normalization Account (WNA), which significantly reduce volatility in the Company's earnings and cash flows.

DBRS remains concerned about the potential rate shock once the Muskrat Falls project, which is currently under construction by Nalcor Energy (Nalcor), comes on line in mid-2020. Nalcor expects that by 2022, rates in the Province of Newfoundland and Labrador (the Province) will increase to 23.3 cents per kilowatt hour (kWh), which is a substantial increase from current rates of around 11.7 cents/kWh. Should the upward pressure on rates affect Newfoundland Power's ability to fully pass on costs, or affect ratepayers' ability to pay their electricity bills, this could result in a negative rating action.

Newfoundland Power's financial risk profile remained solid in 2016 and for the 12 months ending June 30, 2017 (LTM 2017), with all key credit metrics supportive of the current ratings. While capital expenditures (capex) remains higher than historical average, the moderate free cash flow deficits have remained manageable. DBRS expects the Company to continue managing free cash flow deficits in a prudent manner in order to maintain leverage in line with the regulatory capital structure. Going forward, DBRS expects key credit metrics to remain in line with the current rating category.

Financial Information

	12 mos. to June 30	For the year ended December 31				
	2017	**2016**	**2015**	**2014**	**2013**	**2012**
Total debt in capital structure	54.3%	53.8%	54.5%	55.2%	54.6%	55.2%
Cash flow/Total debt	18.8%	18.6%	17.3%	17.8%	18.2%	16.9%
EBIT gross interest coverage (times)	3.07	3.03	3.22	3.06	2.95	2.74
(CFO+interest)/(Interest+sinking fund payment)	3.63	3.44	3.17	3.18	3.16	2.90

Issuer Description

Newfoundland Power is a regulated utility that primarily distributes, but also generates and transmits, electricity to approximately 265,000 customers throughout the island portion of the Province of Newfoundland and Labrador. Newfoundland Power is a subsidiary of Fortis Inc. (rated BBB (high) with a Stable trend by DBRS).

Rating Considerations

Strengths

1. Stable and supportive regulatory environment

Newfoundland Power operates in a stable and supportive regulatory environment that is based on cost of service (COS) regulation. The PUB allows for the pass-through of purchased power costs, and an RSA is in place to absorb fluctuations in purchased power costs relating primarily to the cost of fuel oil used by Newfoundland and Labrador Hydro (NLH; rated A (low) with a Stable trend by DBRS) to generate electricity. Furthermore, the Company also has a WNA to stabilize earnings during extreme weather conditions.

2. Solid financial profile

Newfoundland Power has maintained a solid financial profile, underpinned by the Company's reasonable financial leverage and stable cash flows. During the last 12 months ended June 30, 2017 (LTM 2017), Newfoundland Power's total debt in capital structure remained low at 54.3%, while its cash flow-to-debt and EBIT interest coverage ratios remained solid at 18.8% and 3.07 times, respectively.

3. Stable customer base

Newfoundland Power has a stable customer base with power sales consisting solely of those to residential and commercial customers. As such, the Company is somewhat less sensitive to economic cycles than utilities with exposure to industrial customers, and it has relatively more stable throughputs year over year.

Challenges

1. Reliance on one major power supplier

Newfoundland Power relies heavily on NLH for its power supply, sourcing approximately 93% of its power requirements from this provider. The cost of power purchased from NLH is largely influenced by the market price of bunker C fuel, which has seen some volatility over the past few years. Although this is passed through to Newfoundland Power's customers through the RSA, a potential swing in prices could make it difficult for the Company to increase future rates. NLH is looking to reduce its exposure to highly expensive and volatile oil. The Muskrat Falls project could potentially replace the oil-fired power generated at the Holyrood Thermal Generating Station with cleaner hydroelectric-generated power.

2. Pressure on rates from the Muskrat Falls project

The Muskrat Falls project is an 824-megawatt (MW) hydroelectric generating facility being developed by Nalcor (100% owned by the Province). Costs for the project have increased to approximately $12.7 billion from $9.0 billion in September 2015. It is currently uncertain how costs for the project will be recovered from Newfoundland Power's customers; however, should upward pressure on rates affect the Company's ability to pass on costs, this would negatively affect its credit profile. Nalcor has noted that, based on current projections, rates are expected to increase to 23.3 cents/kWh in 2022 (11.7 cents/kWh in 2017). While Nalcor is currently investigating potential rate mitigation measures, a potential rate shock for customers could affect their ability to pay their electricity bills as well as the electricity throughput, which would be negative for Newfoundland Power's earnings and cash flows. DBRS notes that the Province has directed Nalcor to source $210 million to lower electricity rates starting in 2020–21.

3. Limited population growth

Electricity consumption growth in the Province is largely driven by growth in the customer base, which is dependent on population growth. Over the years, population growth in the Province has been relatively flat, as it is limited by the Province's geographic isolation. Additionally, with the weaker economic outlook for the Province, electricity consumption is expected to remain flat for the medium term.

Earnings and Outlook

	12 mos. to June 30	For the year ended December 31				
(CAD millions where applicable)	2017	2016	2015	2014	2013	2012
Net revenues	231	229	231	227	214	203
EBITDA	169	169	173	167	158	146
EBIT	107	108	116	113	107	98
Gross interest expense	35	36	36	37	36	36
Earning before taxes	54	52	50	49	46	45
Net income before non-recurring items	42	41	39	38	36	35
Reported net income	42	41	39	38	50	37
Actual return on equity	8.4%	8.4%	8.5%	8.6%	8.6%	8.9%
Regulated rate base	N/A	1,061	1,019	965	916	883

2016 Summary

- Newfoundland Power's earnings remained relatively steady in 2016, reflecting the regulated nature of the Company's operations.
- EBITDA and EBIT decreased as a result of (1) lower than anticipated sales and (2) lower recoveries of employee future benefit costs.
- Net income before non-recurring items increased as a result of higher revenues associated with rate base growth.

2017 Summary/Outlook

- Earnings remained stable for LTM 2017, as higher electricity sales and the 1.2% increase for 2016 rates were largely offset by inflationary pressure on operating expenses and higher depreciation from the larger asset base.
- DBRS expects earnings in 2017 to remain stable.

Financial Profile

	12 mos. to June 30	For the year ended December 31				
(CAD millions where applicable)	**2017**	**2016**	**2015**	**2014**	**2013**	**2012**
Net income before non-recurring items	42	41	39	38	36	35
Depreciation & amortization	62	61	57	54	52	48
Deferred income taxes and other	9	6	2	6	7	1
Cash flow from operations	**113**	**107**	**98**	**98**	**95**	**84**
Dividends paid	(24)	(22)	(10)	(24)	(23)	(11)
Capital expenditures	(100)	(103)	(113)	(113)	(89)	(82)
Free cash flow (bef. working cap. changes)	**(12)**	**(18)**	**(25)**	**(39)**	**(18)**	**(9)**
Changes in non-cash work. cap. items	0	12	5	5	(4)	(8)
Net free cash flow	**(12)**	**(6)**	**(20)**	**(34)**	**(22)**	**(17)**
Acquisitions & investments	0	0	0	0	0	0
Proceeds on asset sales	0	0	0	0	0	(1)
Net equity change	(0)	(0)	(0)	(0)	(0)	0
Net debt change	13	7	20	34	22	17
Other	(1)	(1)	0	(0)	(0)	0
Change in cash	**(0)**	**(0)**	**(0)**	**(0)**	**0**	**(0)**
Total debt	599	576	570	549	518	496
Total debt in capital structure	54.3%	53.8%	54.5%	55.2%	54.6%	55.2%
Cash flow/Total debt	18.8%	18.6%	17.3%	17.8%	18.2%	16.9%
EBIT gross interest coverage (times)	3.07	3.03	3.22	3.06	2.95	2.74

2016 Summary

- Newfoundland Power's key credit metrics remained stable in 2016 and supportive of the current ratings.
- Cash flow from operations increased following the rebase of rates for 2016 and lower pension contributions.
- Capex decreased slightly but remained significantly higher than depreciation as the Company continues to invest in renewing aging infrastructure.
- Newfoundland Power uses its annual dividend to maintain a long-term capital structure of 55% debt and 45% equity as approved by the PUB for rate-setting purposes. In 2016, Newfoundland Power paid approximately $22 million in dividends to maintain its leverage in line with the approved capital structure.
- The Company incurred a net free cash flow deficit of approximately $7 million in 2016, which was funded with debt.

2017 Summary/Outlook

- Newfoundland Power's key credit metrics were steady in LTM 2017.
- Cash flow from operations increased largely because of the rate increase effective July 2016.
- The PUB approved Newfoundland Power's 2017 capital plan of $89.4 million in September 2016. The PUB approved supplemental applications for capex of $2.8 million and $3.3 million in February and May 2017, respectively. The Company has spent approximately $38.2 million as of June 30, 2017.
- The Company increased its quarterly common share dividends to $0.64 per share from $0.52 per share in 2017 to maintain its leverage in line with the regulatory capital structure.
- Newfoundland Power issued $75 million of first mortgage sinking fund bonds in June 2017, largely to repay the outstanding balance on its credit facilities.
- DBRS expects Newfoundland Power to continue to maintain its approved capital structure through dividend management and debt financing.

Long-Term Debt Maturities and Liquidity

- Newfoundland Power has a $100.0 million committed revolving unsecured credit facility expiring in August 2022 ($8.5 million outstanding as at June 30, 2017) and a $20.0 million uncommitted demand facility ($2.0 million outstanding as at June 30, 2017).
- The credit facilities contain customary covenants, including maintaining a debt-to-capitalization ratio at or below 65%. The Company was in compliance with all covenants as at June 30, 2017.

(CAD millions - as at June 30, 2017)	2017-2018	2019-2020	2021-2022	Thereafter	Total
First mortgage sinking fund bonds	6.6	13.2	42.4	528.9	591.1
Credit facilities (unsecured)	8.5	0.0	0.0	0.0	8.5
Demand facility (uncommitted)	2.0	0.0	0.0	0.0	2.0
Total	**17.1**	**13.2**	**42.4**	**528.9**	**601.6**

Note: Gross debt; debt issue costs not subtracted from total debt.

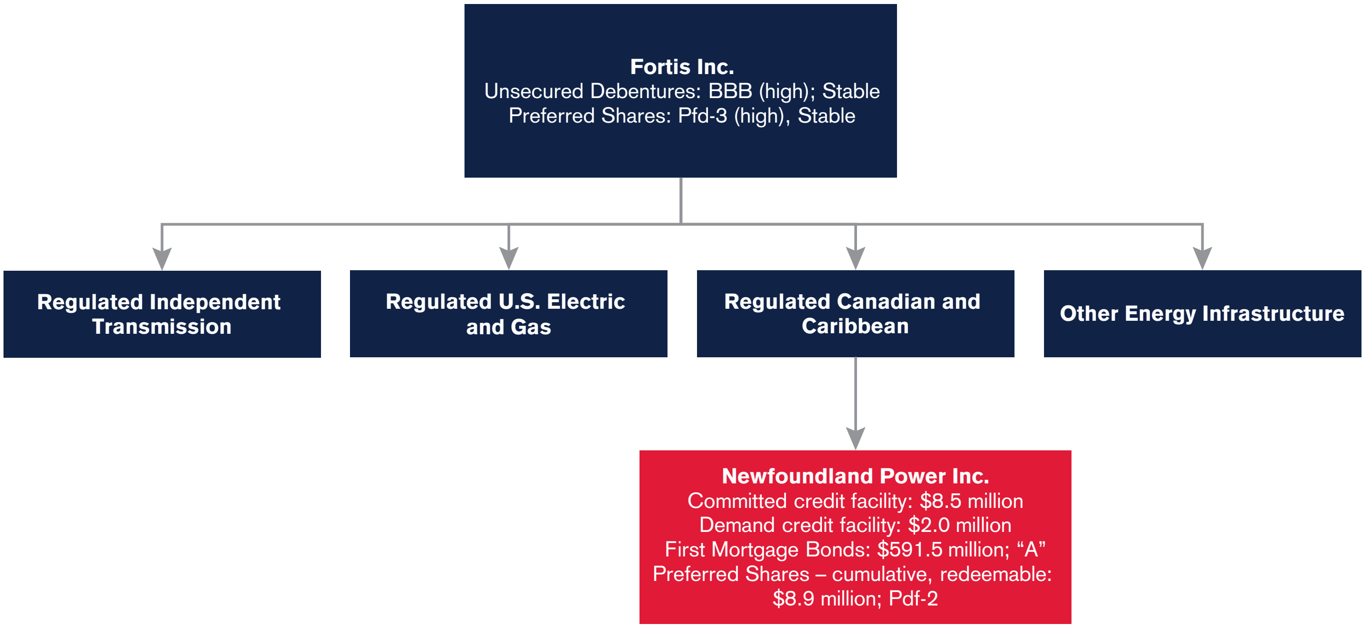
- The debt repayment schedule is very modest in the near term, with the nearest first mortgage sinking fund bond maturity in 2020.

Securities Outstanding (CAD millions)

First mortgage sinking fund bonds:		June 30, 2017
$40 million Series AF, due 2022	10.125%	30.4
$40 million Series AG, due 2020	9.000%	31.2
$40 million Series AH, due 2026	8.900%	32.0
$50 million Series AI, due 2028	6.800%	41.0
$75 million Series AJ, due 2032	7.520%	64.5
$60 million Series AK, due 2035	5.441%	52.8
$70 million Series AL, due 2037	5.901%	63.0
$65 million Series AM, due 2039	6.606%	59.8
$70 million Series AN, due 2043	4.805%	67.9
$75 million Series AO, due 2045	4.446%	73.5
$75 million Series AP, due 2057	3.815%	75.0
		591.1
Credit & demand facilities		10.5
		601.6
Less: current portion		(17.1)
		584.5

- The First Mortgage Bonds are secured by a first fixed and specific charge on property, plant and equipment owned or to be acquired by the Company and by a floating charge on all other assets.
- The Company must meet an Earnings Test, whereby the net earnings are at least twice the annual interest charges on all bonds outstanding after any proposed additional bond issue. Net earnings are considered in a period of any 12 consecutive months terminating within 24 months preceding the delivery of such additional bonds.
- Second, the Company must meet the Additional Property Test, whereby the additional bonds must not exceed 60% of the fair value of the additional property.
- Given the availability of funds under the credit facilities and stable cash flow from operations, the Company's liquidity remains adequate to fund both working capital requirements and cash flow deficits.

Organizational Structure



As at June 30, 2017.

Regulation

Regulatory Overview

- Newfoundland Power is regulated by the PUB, which is responsible for setting electricity rates, approving capex and deciding on the appropriate capital structure and ROE for rate-setting purposes.
- Rates are set based on a COS methodology.
- On June 8, 2016, the PUB issued the Order on Newfoundland Power's 2016/2017 GRA, which established the Company's allowed ROE at 8.50% and common equity at 45% for the 2016 to 2018 rate years. DBRS views the capital structure as favourable and does not expect the moderately lower ROE, as compared with other Canadian jurisdictions, to have a material impact on the Company's cash flows.
- On July 1, 2016, customer electricity rates decreased by approximately 7.9% on average because of (1) a 1.2% increase related to the Company's 2016/2017 GRA and (2) a 9.1% decrease associated with the annual operation of the RSA.
- The PUB approved Newfoundland Power's 2016 capital plan of $107.0 million on September 18, 2015. The PUB additionally fixed the Company's average rate base for the year ending December 31, 2014, at $964.9 million.
- On July 1, 2017, customer electricity rates increased by approximately 8.5% on average because of (1) a flow through adjustment related to the final ruling on NLH's GRA, (2) the annual operation of Hydro's Rate Stabilization Plan, and (3) the annual operation of the Company's RSA.
- The PUB approved Newfoundland Power's 2017 capital plan of $89.4 million on September 12, 2016. The PUB additionally fixed the Company's average rate base for the year ending December 31, 2015, at $1,019 million.
  - The PUB subsequently approved supplemental capital spending of $2.8 million on February 24, 2017, and $3.3 million on May 23, 2017.
- Newfoundland Power filed its 2018 capital plan of $83.9 million on July 7, 2017. The Company also requested approval to fix its average rate base for the year ending December 31, 2016, at $1,061.0 million. A decision is expected by the end of the year.

Regulator-Approved Accounts

Deferral accounts are used to smooth the impact of realized expenses and events differing from forecast.

- **Weather Normalization Reserve (WNR):** The WNR reduces earnings volatility by adjusting electricity purchases and sales to eliminate the variance between normal weather conditions, based on long-term averages, and actual realized weather conditions.

Regulation (CONTINUED)

- **Rate Stabilization Account (RSA):** The RSA allows Newfoundland Power to pass through costs related to changes in the price and quantity of fuel charged by NLH to the end consumer. On July 1 of each year, customer rates are recalculated to amortize the balance in the RSA as of March 31 of the current year over the subsequent 12 months. In the absence of rate regulation, these transactions would be accounted for in a similar manner; however, the amount and timing of the recovery would not be subject to PUB approval. To the extent that actual electricity sales in any period exceed forecast electricity sales used to set customer rates, marginal purchased power expense will exceed related revenue. Effective January 1, 2008, the PUB ordered that variations in purchased power expense caused by differences between the actual unit cost of energy and the cost reflected in customer rates be recovered from (refunded to) customers through the RSA.
- **Demand Management Incentive Account (DMIA):** Through the DMIA, variations in the unit cost of purchased power related to demand are limited, at the discretion of the PUB, to 1.0% of demand costs reflected in customer rates. Balances in this account are recorded as a regulatory asset or regulatory liability on Newfoundland Power's balance sheet. The final balance of regulatory assets and liabilities is determined by the PUB, which considers the merits of the Company's conservation efforts and demand management activities.
- **Pension Expense Variance Deferral Account (PEVDA):** The PEVDA is used when differences exist between the defined benefit pension expense calculated in accordance with designated accounting standards and the pension expense approved by the PUB for rate-setting purposes.
- **Other Post-Employment Benefits (OPEB):** The OPEB cost deferral account is used when differences exist between the OPEB expenses calculated in accordance with designated accounting standards and the OPEB expenses approved by the PUB for rate-setting purposes.
- **Excess Earnings Account (EEA):** Any earnings that exceed the upper limit of the allowed range of return on rate base set by the PUB are credited to the Company's EEA. Amounts credited to the EEA are subject to further order of the PUB.

Newfoundland Power Inc.

Balance sheet

(CAD millions)	June 30 2017	Dec. 31 2016	Dec. 31 2015
Assets			
Cash & equivalents	0	0	0
Accounts receivable	66	76	81
Regulatory assets	20	13	15
Prepaid expenses & other	3	3	12
Total Current Assets	**89**	**92**	**107**
Net fixed assets	1,092	1,082	1,038
Future income tax assets	194	191	180
Intangibles	21	21	18
Regulatory assets	135	143	151
Pensions & Other	13	11	1
Total Assets	**1,544**	**1,540**	**1,495**

	June 30 2017	Dec. 31 2016	Dec. 31 2015
Liabilities & sh. Equity			
S.T. borrowings	2	2	2
Accounts payable	41	79	81
Current portion L.T.D.	15	66	54
Other current liab.	14	12	10
Total Current Liab.	**72**	**159**	**147**
Long-term debt	582	508	513
Provisions	244	238	230
Deferred income taxes	141	140	128
Other L.T. liab.	1	2	1
Preferred shares	9	9	9
Common equity	495	485	466
Total Liab. & SE	**1,544**	**1,540**	**1,495**

Balance Sheet & Liquidity & Capital Ratios	12 mos. to June 30 2017	For the year ended December 31 2016	2015	2014	2013	2012
Current ratio	1.24	0.58	0.73	0.68	0.94	0.77
Total debt in capital structure	54.3%	53.8%	54.5%	55.2%	54.6%	55.2%
Cash flow/Total debt	18.8%	18.6%	17.3%	17.8%	18.2%	16.9%
(Cash flow-dividends)/Capex (times)	0.88	0.83	0.78	0.66	0.80	0.88
Dividend payout ratio	58.7%	54.4%	25.6%	62.6%	64.8%	32.6%
Coverage Ratios (times)						
EBIT gross interest coverage	3.07	3.03	3.22	3.06	2.95	2.74
EBITDA gross interest coverage	4.85	4.72	4.79	4.52	4.36	4.05
Fixed-charges coverage	3.00	2.96	3.15	3.00	2.88	2.68
Profitability Ratios						
EBITDA margin	73.0%	73.7%	75.0%	73.7%	73.9%	72.0%
EBIT margin	46.3%	47.2%	50.4%	49.9%	49.9%	48.6%
Profit margin	18.1%	17.7%	17.0%	16.7%	16.8%	17.1%
Return on equity	8.4%	8.4%	8.5%	8.6%	8.6%	8.9%
Return on capital	6.0%	6.1%	6.3%	6.5%	6.6%	6.8%

Operating Statistics

	For the year ended December 31				
Electricity sales - breakdown (GWh)	**2016**	**2015**	**2014**	**2013**	**2012**
Residential	3,655	3,655	3,613	3,531	3,441
General service	2,295	2,302	2,286	2,232	2,211
Total sales	**5,950**	**5,957**	**5,899**	**5,763**	**5,652**
Growth in volume throughputs	-0.1%	1.0%	2.4%	2.0%	1.8%
Customers					
Residential	229,815	227,455	224,824	221,995	218,290
Commercial	34,591	34,319	34,055	33,623	33,241
Total	**264,406**	**261,774**	**258,879**	**255,618**	**251,531**
Energy generated and purchased (GWh)					
Energy generated	427	432	430	429	432
Energy purchased	5,868	5,877	5,817	5,678	5,544
Energy generated + purchased	**6,295**	**6,309**	**6,247**	**6,107**	**5,976**
Less: transmission losses + internal use	345	353	348	344	324
Total sales	**5,950**	**5,956**	**5,899**	**5,763**	**5,652**
System losses and internal use	5.8%	5.9%	5.9%	6.0%	5.7%
Installed generation capacity (MW)					
Hydroelectric	97	97	97	97	97
Gas turbine	37	37	37	37	37
Diesel	5	5	5	5	6
Total	**139**	**139**	**139**	**139**	**140**
Native peak demand (MW)	1,381	1,382	1,343	1,281	1,241
Rate base (CAD millions)	1,061	1,019	965	916	883

Rating History

	Current	2016	2015	2014	2013	2012
Issuer Rating	A	A	A	A	A	A
First Mortgage Bonds	A	A	A	A	A	A
Preferred Shares – cumulative, redeemable	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2

Previous Action

- Confirmed, August 13, 2016.

Previous Report

- Newfoundland Power Inc.: Rating Report, August 19, 2016.

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on www.dbrs.com.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

The DBRS group of companies consists of DBRS, Inc. (Delaware, U.S.)(NRSRO, DRO affiliate); DBRS Limited (Ontario, Canada)(DRO, NRSRO affiliate); DBRS Ratings Limited (England and Wales)(CRA, NRSRO affiliate, DRO affiliate); and DBRS Ratings México, Institución Calificadora de Valores S.A. de C.V. (Mexico)(CRA, NRSRO affiliate, DRO affiliate). Please note that DBRS Ratings Limited was registered as an NRSRO affiliate on July 14, 2017. For more information on regulatory registrations, recognitions and approvals, please see: http://www.dbrs.com/research/225752/highlights.pdf.

Newfoundland Power Inc.

Comparative Financial Forecasts
2019 - 2020
Statements of Income
($000s)

		2019		2020	
		Existing	**Proposed**	**Existing**	**Proposed**
1	Revenue from rates	655,841	661,467	657,459	664,118
2	Transfers from (to) the RSA	(6,337)	3,601	(6,744)	5,650
3		649,504	665,068	650,715	669,767
4					
5	Purchased power expense	430,627	429,949	430,644	429,144
6	Demand management incentive account adjustments	-	-	-	-
7		430,627	429,949	430,644	429,144
8					
9	Contribution	218,877	235,119	220,071	240,624
10					
11	Other revenue[1]	5,584	5,612	5,375	5,594
12					
13	Other expenses:				
14	Operating expenses[2]	64,682	62,679	66,571	64,610
15	Employee future benefit costs	9,080	9,080	7,566	7,566
16	Deferred cost recoveries and amortizations	-	649	-	(324)
17	Depreciation	62,314	62,350	64,797	64,908
18	Finance charges	35,948	36,232	37,034	37,442
19		172,024	170,990	175,968	174,202
20					
21	Income before income taxes	52,437	69,741	49,478	72,016
22	Income taxes[2]	15,814	20,320	14,985	21,078
23					
24	Net income	36,623	49,421	34,493	50,938
25	Preferred dividends	552	552	552	552
26					
27	Earnings applicable to common shares[2]	36,071	48,869	33,941	50,386
28					
29	**Rate of Return and Credit Metrics**				
30	Rate of Return on Rate Base (%)	6.34	7.47	6.09	7.49
31	Regulated Return on Book Equity (%)	7.04	9.50	6.44	9.50
32	Interest Coverage (times)	2.2	2.6	2.0	2.6
33	CFO Pre-W/C + Interest / Interest (times)	3.7	4.0	3.7	4.1
34	CFO Pre-W/C / Debt (%)	15.8	17.7	15.4	17.8

[1] Other revenue for proposed excludes interest on the RSA.
[2] Shown after adjustment for non-regulated expenses.

Newfoundland Power Inc.

Comparative Financial Forecasts
2019 - 2020
Statements of Income
($000s)

		2019		2020	
		Existing	**Proposed**	**Existing**	**Proposed**
1	Balance - Beginning	430,876	430,876	453,175	456,891
2	Net income for the period	34,483	47,282	32,272	48,716
3	Allocation of Part VI.1 Tax	752	752	752	752
4		466,111	478,910	486,199	506,359
5					
6	Dividends				
7	Preference shares	552	552	552	552
8	Common shares	12,384	21,466	25,594	42,520
9		12,936	22,018	26,146	43,072
10	Balance - End of Period	453,175	456,892	460,053	463,288

Newfoundland Power Inc.

Comparative Financial Forecasts
2019 - 2020
Balance Sheets
($000s)

		2019		2020	
		Existing	**Proposed**	**Existing**	**Proposed**
1	**Assets**				
2	**Current assets**				
3	Accounts receivable	88,860	85,018	89,788	84,561
4	Materials and supplies	1,527	1,527	1,556	1,556
5	Prepaid expenses	2,108	2,108	2,148	2,148
6	Regulatory assets	788	8,627	1,049	13,625
7		93,283	97,280	94,541	101,890
8					
9	**Property, plant and equipment**	1,190,603	1,192,714	1,227,804	1,232,007
10	**Intangible assets**	26,800	26,929	27,955	28,184
11	**Regulatory assets**	315,019	315,127	307,650	307,776
12	**Defined benefit pension plans**	26,153	26,153	33,640	33,640
13	**Other assets**	1,613	1,613	1,614	1,614
14		1,653,471	1,659,816	1,693,204	1,705,111
15					
16					
17	**Liabilities and shareholders' equity**				
18	Current liabilities				
19	Accounts payable and accrued charges	77,572	80,846	77,462	80,850
20	Interest payable	6,536	6,536	6,606	6,606
21	Defined benefit pension plans	225	225	218	218
22	Other post employment benefits	3,709	3,709	4,165	4,165
23	Current instalments of long-term debt	63,759	63,477	79,318	85,030
24	Deferred income taxes	-	-	-	-
25		151,802	154,793	167,769	176,869
26					
27	**Regulatory liabilities**	168,499	168,258	177,436	176,969
29	**Other post employment benefits**	80,805	80,805	81,892	81,892
30	**Other liabilities**	1,066	1,066	1,066	1,066
31	**Deferred income taxes**	156,550	156,427	155,922	155,961
32	**Long-term debt**	562,337	562,337	569,828	569,828
33					
34	**Shareholders' equity**				
35	**Common shares**	70,321	70,321	70,321	70,321
36	**Preference shares**	8,917	8,917	8,917	8,917
37	**Retained earnings**	453,175	456,892	460,053	463,288
38		532,413	536,130	539,291	542,526
39		1,653,471	1,659,816	1,693,204	1,705,111

Newfoundland Power Inc.

Comparative Financial Forecasts
2019 - 2020
Statements of Cash Flows
($000s)

		2019		2020	
		Existing	**Proposed**	**Existing**	**Proposed**
1	**Cash From (Used In) Operating Activities**				
2	Net Earnings	34,483	47,282	32,272	48,716
3					
4	**Items Not Affecting Cash:**				
5	Amortization of property, plant and equipment	64,614	64,647	67,011	67,112
6	Amortization of intangible assets and other	3,806	3,812	4,128	4,147
7	Change in long-term regulatory assets and liabilities	4,467	4,359	8,600	8,582
8	Deferred income taxes	630	507	(628)	(466)
9	Employee future benefits	(6,374)	(6,374)	(8,194)	(8,194)
10	Other	293	282	284	273
11		101,919	114,515	103,473	120,170
12					
13	Change in non-cash working capital	4,823	4,098	(287)	(3,523)
14		106,742	118,613	103,186	116,647
15					
16	**Investing Activities**				
17	Capital expenditures	(95,825)	(98,199)	(98,308)	(100,715)
18	Intangible asset expenditures	(5,750)	(5,885)	(5,092)	(5,211)
19	Contributions from customers and security deposits	3,509	3,509	3,499	3,499
20		(98,066)	(100,575)	(99,901)	(102,427)
21					
22	**Financing Activities**				
23	Net proceeds (repayment) of committed credit facility	10,860	10,580	(14,789)	(8,798)
24	Proceeds from long-term debt	-	-	75,000	75,000
25	Repayment of long-term debt	(6,600)	(6,600)	(36,950)	(36,950)
26	Payment of debt financing costs	-	-	(400)	(400)
27	Dividends				
28	Preference shares	(552)	(552)	(552)	(552)
29	Common shares	(12,384)	(21,466)	(25,594)	(42,520)
30		(8,676)	(18,038)	(3,285)	(14,220)
31					
32	**Change in Cash**	-	-	-	-
33	**Cash (Bank Indebtedness), Beginning of Year**	-	-	-	-
34	**Cash (Bank Indebtedness), End of Year**	-	-	-	-

Newfoundland Power Inc.

Comparative Financial Forecasts
2019 - 2020
Average Rate Base[1]
($000s)

		2019		2020	
		Existing	Proposed	Existing	Proposed
1	Plant Investment	1,091,011	1,092,182	1,123,671	1,127,189
2					
3	Additions to Rate Base				
4	Defined Benefit Pension Costs	91,210	91,210	95,350	95,350
5	Deferred Credit Facility Costs	68	42	39	-
6	Cost Recovery Deferral - Hearing Costs	-	353	-	530
7	Cost Recovery Deferral - Conservation	16,993	16,993	17,219	17,219
8	Customer Finance Programs	1,545	1,545	1,575	1,575
9		109,816	110,143	114,183	114,674
10					
11	Deductions from Rate Base				
12	Weather Normalization Reserve	136	136	-	-
13	Other Post Employee Benefits	57,846	57,846	61,415	61,415
14	Customer Security Deposits	1,066	1,066	1,066	1,066
15	Accrued Pension Obligation	5,174	5,174	5,469	5,469
16	Accumulated Deferred Income Taxes	6,977	6,977	9,808	9,808
17	2019 Revenue Surplus	-	227	-	340
18		71,199	71,426	77,758	78,098
19					
20	Average Rate Base Before Allowances	1,129,628	1,130,899	1,160,096	1,163,765
21					
22	Cash Working Capital Allowance	8,212	9,726	8,169	9,817
23					
24	Materials and Supplies Allowance	5,925	5,668	6,037	5,775
25					
26	Average Rate Base at Year End	1,143,765	1,146,293	1,174,302	1,179,357

[1] All amounts shown are averages.

Newfoundland Power Inc.

Comparative Financial Forecasts
2019 - 2020
Weighted Average Cost of Capital
($000s)

		2019		2020	
		Existing	**Proposed**	**Existing**	**Proposed**
1	**Average Capitalization**				
2	Debt	623,801	623,660	637,582	640,297
3	Preference Shares	8,917	8,917	8,917	8,917
4	Common Equity	512,346	514,206	526,936	530,413
5		1,145,064	1,146,783	1,173,435	1,179,627
6					
7	**Average Capital Structure (%)**				
8	Debt	54.48	54.38	54.33	54.28
9	Preference Shares	0.78	0.78	0.76	0.76
10	Common Equity	44.74	44.84	44.91	44.96
11		100.00	100.00	100.00	100.00
12					
13					
14	**Cost of Capital (%)**				
15	Debt	5.76	5.81	5.81	5.84
16	Preference Shares	6.19	6.19	6.19	6.19
17	Common Equity	7.04	9.50	6.44	9.50
18					
19					
20	**Weighted Average Cost of Capital (%)**				
21	Debt	3.14	3.16	3.15	3.17
22	Preference Shares	0.05	0.05	0.05	0.05
23	Common Equity	3.15	4.26	2.89	4.27
24		6.34	7.47	6.09	7.49

Newfoundland Power Inc.

Comparative Financial Forecasts
2019 - 2020
Rate of Return on Rate Base
($000s)

		2019		2020	
		Existing	**Proposed**	**Existing**	**Proposed**
1	Regulated Return on Equity	36,071	48,869	33,941	50,386
2	Return on Preferred Equity	552	552	552	552
3		36,623	49,421	34,493	50,938
4					
5	Finance Charges				
6	Interest on Long-term Debt	35,374	35,374	37,080	37,080
7	Other Interest	1,354	1,662	755	1,189
8	Amortization of Bond Issue Expenses	224	224	219	219
9	AFUDC	(1,021)	(1,046)	(1,039)	(1,064)
10		35,931	36,214	37,015	37,424
11					
12	Return on Rate Base	72,554	85,635	71,508	88,362
13					
14	Average Rate Base	1,143,765	1,146,293	1,174,302	1,179,357
15					
16	Rate of Return on Rate Base (%)	6.34	7.47	6.09	7.49

Newfoundland Power Inc.

Comparative Financial Forecasts
2019 - 2020
Inputs and Assumptions

Energy Forecasts: Energy forecasts are based on economic indicators taken from the Conference Board of Canada, Provincial Outlook, Long Term Economic Forecast, dated January 19, 2018.

Revenue Forecast: The revenue forecast is based on the Customer, Energy and Demand forecast dated April 6, 2018.

Forecast revenues based on Existing Rates for 2019 and 2020 reflect: (i) recovery through the RSA for amounts associated with the Energy Supply Cost Variance Adjustment Clause; (ii) recovery through the RSA of amounts associated with variances in employee future benefit costs; (iii) recovery through the RSA of amounts associated with the Weather Normalization reserve; and (iv) recovery through the RSA of certain costs related to the implementation of the CDM program portfolio; all of which were approved by the Board in Order Nos. P.U. 32 (2007), P.U. 43 (2009), P.U. 31 (2010), P.U. 8 (2011), P.U. 13 (2013), P.U. 18 (2015) and P.U. 23 (2017).

Purchased Power Expense: Purchased power expense reflects Newfoundland and Labrador Hydro's rates approved by the Board and the Customer, Energy and Demand Forecast dated April 6, 2018.

Purchased power expense for the Existing forecasts reflects the operation of the Demand Management Incentive Account approved by the Board in Order No. P.U. 32 (2007). This mechanism provides for recovery of demand costs that are in excess of unit cost demand costs included in the most recent test year.

Variances in demand costs under the Proposed forecasts are reflected in the 2019 and 2020 revenue requirements.

Employee Future Benefit Costs: Pension funding is based on the actuarial valuation dated as at December 31, 2017.

Pension expense and OPEBs expense discount rate is 3.60% for 2019 and 2020.

Forecast return on pension assets is assumed to be 5.25% for 2019 and 2020.

Cost Recovery Deferrals: The 2019 and 2020 forecasts include the deferred recovery over a 7-year period of certain conservation program costs as reflected in the Application.

The 2019 and 2020 forecasts include the deferred recovery over a 34-month period of $0.9 million related to the March 1, 2019 rate implementation date.

Depreciation Rates: Depreciation costs for 2019 and 2020 include an approximately $0.6 million reserve variance adjustment resulting from the *2014 Depreciation Study* .

Operating Costs: Operating forecasts for 2019 and 2020 reflect the most recent management estimates.

The 2019 and 2020 forecasts include the deferred recovery over a 34-month period of $1.0 million in external costs related to the *2019/2020 General Rate Application.*

Newfoundland Power Inc.

Comparative Financial Forecasts
2019 - 2020
Inputs and Assumptions

Capital Expenditure:	Capital Expenditures for 2019 and 2020 are based on the *2018 Capital Budget Application* approved on November 6, 2017.
Short-Term Interest Rates:	Average short-term interest rates are assumed to be 3.27% for 2019 and 3.60% for 2020.
Long-Term Debt:	A $75.0 million long-term debt issue is forecast to be completed in April 2020. The debt is forecast for 30 years at a coupon rate of 5.25%. Debt repayments will be in accordance with the normal sinking fund provisions for existing outstanding debt.
Dividends:	Common dividend payouts are forecast based on maintaining a target common equity component of 45%.
Income Tax:	Income tax expense reflects a statutory income tax rate of 30% for 2019 and 2020.

Newfoundland Power Inc.

Forecast Average Rate Base[1]
2019 - 2020
($000s)

		2019	2020
1	Plant Investment	1,092,182	1,127,189
2			
3	Additions to Rate Base		
4	Defined Benefit Pension Costs	91,210	95,350
5	Deferred Credit Facility Costs	42	-
6	Cost Recovery Deferral - Hearing Costs	353	530
7	Cost Recovery Deferral - Conservation	16,993	17,219
8	Customer Finance Programs	1,545	1,575
9		110,143	114,674
10			
11	Deductions from Rate Base		
12	Weather Normalization Reserve	136	-
13	Other Post Employee Benefits	57,846	61,415
14	Customer Security Deposits	1,066	1,066
15	Accrued Pension Obligation	5,174	5,469
16	Accumulated Deferred Income Taxes	6,977	9,808
17	2019 Revenue Surplus	227	340
18		71,426	78,098
19			
20	Average Rate Base Before Allowances	1,130,899	1,163,765
21			
22	Cash Working Capital Allowance	9,726	9,817
23			
24	Materials and Supplies Allowance	5,668	5,775
25			
26	Average Rate Base at Year End	1,146,293	1,179,357

[1] Based upon proposed rates. All amounts shown are averages.

Newfoundland Power Inc.

2019 Revenue Requirement[1]
($000s)

		Existing	Changes	Proposed
1	**Costs**			
2	Power Supply Cost	430,627	(678)	429,949
3	Operating Costs	64,682	(2,003)	62,679
4	Employee Future Benefit Costs	9,080	-	9,080
5	Deferred Cost Recoveries and Amortizations	-	649	649
6	Depreciation[2]	62,314	36	62,350
7	Income Taxes	15,814	4,506	20,320
8		582,517	2,510	585,027
9				
10	**Return on Rate Base**	72,554	13,081	85,635
11				
12	**2019 Revenue Requirement**	655,071	15,591	670,662
13				
14	**Adjustments**			
15	Other Revenue[3]	(5,584)	(28)	(5,612)
16	Interest on Security Deposits	18	-	18
17	Energy Supply Cost Variance Adjustments	4,502	(3,438)	1,064
18	Other	1,834	(6,499)	(4,665)
19		770	(9,965)	(9,195)
20				
21	**2019 Revenue Requirement from Rates[4]**	655,841	5,626	661,467

[1] See *Volume 1, Application, Company Evidence and Exhibits, Section 4.3: 2019 and 2020 Revenue Requirements* for a summary of the Company's 2019 revenue requirement proposals.

[2] The increase in depreciation expense is related to increased capitalization of pension costs. See *Volume 1, Application, Company Evidence and Exhibits, Section 3.4: Regulatory Accounting Matters.*

[3] Excludes equity component of capitalized interest. Other revenue for proposed also excludes interest on the RSA.

[4] Existing revenue requirement for 2019 excludes price elasticity impacts related to revenue of $607,000. The required revenue increase of $6,233,000 in 2019 (see Exhibit 9, page 1 of 2, line 1, column E) is comprised of $5,626,000 and price elasticity impacts related to revenue of $607,000 (see Exhibit 9, page 1 of 2, line 1, column D).

Newfoundland Power Inc.

2020 Revenue Requirement[1]
($000s)

		Existing	Changes	Proposed
1	**Costs**			
2	Power Supply Cost	430,644	(1,500)	429,144
3	Operating Costs	66,571	(1,961)	64,610
4	Employee Future Benefit Costs	7,566	-	7,566
5	Deferred Cost Recoveries and Amortizations	-	(324)	(324)
6	Depreciation[2]	64,797	111	64,908
7	Income Taxes	14,985	6,093	21,078
8		584,563	2,419	586,982
9				
10	**Return on Rate Base**	71,508	16,854	88,362
11				
12	**2020 Revenue Requirement**	656,071	19,273	675,344
13				
14	**Adjustments**			
15	Other Revenue[3]	(5,375)	(219)	(5,594)
16	Interest on Security Deposits	18	-	18
17	Energy Supply Cost Variance Adjustments	4,357	(4,357)	-
18	Other	2,388	(8,038)	(5,650)
19		1,388	(12,614)	(11,226)
20				
21	**2020 Revenue Requirement from Rates[4]**	657,459	6,659	664,118

[1] See *Volume 1, Application, Company Evidence and Exhibits, Section 4.3: 2019 and 2020 Revenue Requirements* for a summary of the Company's 2020 revenue requirement proposals.

[2] The increase in depreciation expense is related to increased capitalization of pension costs. See *Volume 1, Application, Company Evidence and Exhibits, Section 3.4: Regulatory Accounting Matters.*

[3] Excludes equity component of capitalized interest. Other revenue for proposed also excludes interest on the RSA.

[4] Existing revenue requirement for 2020 excludes price elasticity impacts related to revenue of $1,301,000. The required revenue increase of $7,960,000 in 2020 (see Exhibit 9, page 2 of 2, line 1, column E) is comprised of $6,659,000 and price elasticity impacts related to revenue of $1,301,000 (see Exhibit 9, page 2 of 2, line 1, column D).

Newfoundland Power Inc.

2019 Return on Rate Base
($000s)

		Existing	Changes	Proposed
1				
2	**Average Capitalization**			
3	Debt	623,801	(141)	623,660
4	Preference Shares	8,917	-	8,917
5	Common Equity	512,346	1,860 [1]	514,206
6		1,145,064	1,719	1,146,783
7				
8	**Average Capital Structure (%)**			
9	Debt	54.48	-0.10	54.38
10	Preference Shares	0.78	0.00	0.78
11	Common Equity	44.74	0.10 [1]	44.84
12		100.00	0.00	100.00
13				
14	**Cost of Capital (%)**			
15	Debt	5.76	0.05	5.81
16	Preference Shares	6.19	0.00	6.19
17	Common Equity	7.04	2.46 [1]	9.50
18				
19	**Weighted Average Cost of Capital (%)**			
20	Debt	3.14	0.02	3.16
21	Preference Shares	0.05	0.00	0.05
22	Common Equity	3.15	1.11	4.26
23		6.34	1.13	7.47
24				
25	**Return on Rate Base**			
26	Return on Debt	35,931	283	36,214
27	Return on Preference Shares	552	-	552
28	Return on Common Equity	36,071	12,798 [1]	48,869
29		72,554	13,081	85,635

[1] Reflects the Company's proposed return on common equity of 9.5% in 2019.

Newfoundland Power Inc.

2020 Return on Rate Base
($000s)

		Existing	Changes	Proposed
1				
2	**Average Capitalization**			
3	Debt	637,582	2,715	640,297
4	Preference Shares	8,917	-	8,917
5	Common Equity	526,936	3,477 [1]	530,413
6		1,173,435	6,192	1,179,627
7				
8	**Average Capital Structure (%)**			
9	Debt	54.33	-0.05	54.28
10	Preference Shares	0.76	0.00	0.76
11	Common Equity	44.91	0.05 [1]	44.96
12		100.00	0.00	100.00
13				
14	**Cost of Capital (%)**			
15	Debt	5.81	0.03	5.84
16	Preference Shares	6.19	0.00	6.19
17	Common Equity	6.44	3.06 [1]	9.50
18				
19	**Weighted Average Cost of Capital (%)**			
20	Debt	3.15	0.02	3.17
21	Preference Shares	0.05	0.00	0.05
22	Common Equity	2.89	1.38	4.27
23		6.09	1.40	7.49
24				
25	**Return on Rate Base**			
26	Return on Debt	37,015	409	37,424
27	Return on Preference Shares	552	-	552
28	Return on Common Equity	33,941	16,445 [1]	50,386
29		71,508	16,854	88,362

[1] Reflects the Company's proposed return on common equity of 9.5% in 2020.

Newfoundland Power Inc.

2019 Revenue Requirement to Revenue from Rates Reconciliation
($000s)

		Existing	Proposed	Difference	Price Elasticity[3]	Proposed Increase[4]
		A	B	C	D	E
1	**Revenue From Rates**	655,841[1]	661,467[2]	5,626[5]	607	6,233
2						
3	**RSA Charges[6]**	(11,496)	(11,484)	12	(12)	-
4						
5	**MTA Charges**	18,043	18,200	157	16	173
6						
7	**Total**	662,388	668,183	5,795	611	6,406

[1] 2019 revenue from existing rates from *Exhibit 7*, page 1 of 2.
[2] Revenue from proposed rates, reflecting elasticity effects of proposed increase, from *Exhibit 7*, page 1 of 2. Revenue from proposed rates reflect revenue from existing rates for January to February plus revenue from proposed rates for March to December of 2019.
[3] Elasticity impacts represent revenue reductions from reduced customer usage as a result of the proposed rate increase.
[4] The difference between existing and proposed forecasts plus additional revenue requirement to offset price elasticity impact (Column C + Column D).
[5] *Exhibit 7* of the Application indicates a required increase in 2019 revenue from rates of $5,626,000 net of elasticity effects.
[6] The RSA and MTA billings are determined using the RSA and MTA Factors effective July 1, 2017.

Newfoundland Power Inc.

2020 Revenue Requirement to Revenue from Rates Reconciliation
($000s)

		Existing	Proposed	Difference	Price Elasticity[3]	Proposed Increase[4]
		A	B	C	D	E
1	**Revenue From Rates**	657,459 [1]	664,118 [2]	6,659 [5]	1,301	7,960
2						
3	**RSA Charges[6]**	(11,514)	(11,489)	25	(25)	-
4						
5	**MTA Charges**	18,089	18,275	186	39	225
6						
7	**Total**	664,034	670,904	6,870	1,315	8,185 [7]

[1] 2020 revenue from existing rates from *Exhibit 7,* page 2 of 2.
[2] Revenue from proposed rates, reflecting elasticity effects of proposed increase, from *Exhibit 7,* page 2 of 2.
[3] Elasticity impacts represent revenue reductions from reduced customer usage as a result of the proposed rate increase.
[4] Difference between existing and proposed forecasts plus additional revenue requirement to offset price elasticity impact (Column C + Column D).
[5] *Exhibit 7* of the Application indicates a required increase in 2020 revenue from rates of $6,659,000 net of elasticity effects.
[6] The RSA and MTA billings are determined using the RSA and MTA Factors effective July 1, 2017.
[7] See *Exhibit 10,* Column E.

Newfoundland Power Inc.

2020 Average Customer Billing Impacts
($000s)

Forecast Impacts by Rate Class Under Existing and Proposed Rates
(includes July 1, 2017 RSA and MTA)

	Category	Existing Rates	Adjustment Due to Price Elasticity	Adjusted Existing Rates	Proposed Rates	Increase	Rate Increase
1		(A) [1]	(B) [2]	(C) [3]	(D) [4]	(E) [5]	(F) [6]
2							
3	1.1 Domestic	417,104	(1,204)	415,900	421,039	5,139	1.2%
4	1.1S Domestic Seasonal	1,898	-	1,898	1,921	23	1.2%
5	Total Domestic	419,002	(1,204)	417,798	422,960	5,162	1.2%
6							
7	2.1 General Service 0-100 kW	90,264	(104)	90,160	91,274	1,114	1.2%
8	2.3 General Service 110-1000 kVA	98,357	-	98,357	99,574	1,217	1.2%
9	2.4 General Service over 1000 kVA	37,281	-	37,281	37,742	461	1.2%
10	Total General Service	225,902	(104)	225,798	228,590	2,792	1.2%
11							
12	4.1 Street and Area Lighting	16,699	-	16,699	16,901	202	1.2%
13	Forfeited Discounts	2,431	(7)	2,424	2,453	29	1.2%
14							
15	**Total**	664,034	(1,315)	662,719	670,904	8,185	1.2%

[1] Column A is the forecast revenue plus RSA and MTA under existing rates, based on the 2020 test year sales forecast without elasticity impacts. See *Exhibit 9* , page 2 of 2, Column A.
[2] Column B is the elasticity impact on existing customer billings reflecting a 1.2% average increase in customer rates.
[3] Column C is the forecast customer billings under existing rates including elasticity impacts (Column A + Column B).
[4] Column D is the forecast customer billings under proposed rates including elasticity impacts. See *Exhibit 9* , page 2 of 2, Column B.
[5] Column E is the difference between forecast under proposed rates and that under existing rates adjusted for elasticity (Column D - Column C).
[6] Column F is the forecast rate increase (Column E / Column C).

NEWFOUNDLAND POWER INC.
Summary of Existing and Proposed Customer Rates
(Includes Municipal Tax and Rate Stabilization Adjustments)

	July 1, 2017 Existing Rates	March 1, 2019 Proposed Rates
Domestic - Rate #1.1		
Basic Customer Charge		
Not Exceeding 200 Amp Service	\$16.04/month	\$16.23/month
Exceeding 200 Amp Service	\$21.04/month	\$21.23/month
Energy Charge - All kilowatt hours	10.604 ¢/kWh	10.736 ¢/kWh
Minimum Monthly Charge		
Not Exceeding 200 Amp Service	\$16.04/month	\$16.23/month
Exceeding 200 Amp Service	\$21.04/month	\$21.23/month
Prompt Payment Discount	1.5%	1.5%
Domestic - Rate #1.1S		
Basic Customer Charge		
Not Exceeding 200 Amp Service	\$16.04/month	\$16.23/month
Exceeding 200 Amp Service	\$21.04/month	\$21.23/month
Energy Charge		
Winter Seasonal	11.557 ¢/kWh	11.689¢/kWh
Non-Winter Seasonal	9.307 ¢/kWh	9.439 ¢/kWh
Minimum Monthly Charge		
Not Exceeding 200 Amp Service	\$16.04/month	\$16.23/month
Exceeding 200 Amp Service	\$21.04/month	\$21.23/month
Prompt Payment Discount	1.5%	1.5%

NEWFOUNDLAND POWER INC.
Summary of Existing and Proposed Customer Rates
(Includes Municipal Tax and Rate Stabilization Adjustments)

	July 1, 2017 Existing Rates	March 1, 2019 Proposed Rates
G.S. 0-100 kW (110 kVA) - Rate #2.1		
Basic Customer Charge		
Unmetered	$17.20/month	$12.50/month
Single Phase	$21.20/month	$20.50/month
Three Phase	$27.20/month	$32.50/month
Demand Charge Regular	$9.16/kW - winter $6.66/kW - other	$9.25/kW - winter $6.75/kW - other
Energy Charge		
First 3,500 kilowatt-hours	10.511 ¢/kWh	10.640 ¢/kWh
All excess kilowatt-hours	7.746 ¢/kWh	7.844 ¢/kWh
Maximum Monthly Charge	18.728 ¢/kWh + B.C.C.	18.957 ¢/kWh + B.C.C.
Minimum Monthly Charge		
Unmetered	$17.20/month	$12.50/month
Single Phase	$21.20/month	$20.50/month
Three Phase	$33.20/month	$32.50/month
Prompt Payment Discount	1.5%	1.5%
G.S. 110-1000 kVA - Rate #2.3		
Basic Customer Charge	$49.57/month	$50.17/month
Demand Charge	$7.74/kVA-winter $5.24/kVA-other	$7.82/kVA-winter $5.32/kVA-other
Energy Charge		
First 150 kWh per kVA of demand (max. 50,000)	8.894 ¢/kWh	9.004 ¢/kWh
All Excess kWh	7.055 ¢/kWh	7.143 ¢/kWh
Maximum Monthly Charge	18.728 ¢/kWh + B.C.C.	18.957 ¢/kWh + B.C.C.
Minimum Monthly Charge	$49.57/month	$50.17/month
Prompt Payment Discount	1.5%	1.5%

NEWFOUNDLAND POWER INC.
Summary of Existing and Proposed Customer Rates
(Includes Municipal Tax and Rate Stabilization Adjustments)

	July 1, 2017 Existing Rates	March 1, 2019 Proposed Rates
G.S. 1000 kVA and Over - Rate #2.4		
Basic Customer Charge	$86.39/month	$87.44/month
Demand Charge	$7.46/kVA-winter $4.96/kVA-other	$7.53/kVA-winter $5.03/kVA-other
Energy Charge		
First 75,000 kWh	8.564 ¢/kWh	8.669 ¢/kWh
All Excess kWh	6.986 ¢/kWh	7.071 ¢/kWh
Maximum Monthly Charge	18.728 ¢/kWh + B.C.C.	18.957 ¢/kWh + B.C.C.
Minimum Monthly Charge	$86.39/month	$87.44/month
Prompt Payment Discount	1.5%	1.5%

NEWFOUNDLAND POWER INC.

Summary of Existing and Proposed Customer Rates
(Includes Municipal Tax and Rate Stabilization Adjustments)

Street and Area Lighting Rates

		July 1, 2017 Existing Rates	March 1, 2019 Proposed Rates
Fixtures			
Sentinel/Standard			
High Pressure Sodium	100W	$17.13	$17.24
	150W	21.06	21.27
	250W	29.16	29.69
	400W	39.91	40.99
Light Emitting Diode	LED 100	n/a	$15.85
	LED 150	n/a	17.30
	LED 250	n/a	22.11
	LED 400	n/a	24.97
Post Top			
High Pressure Sodium	100W	$18.49	$18.57
Poles			
Wood		$6.29	$6.72
30' Concrete or Metal, direct buried		8.99	9.58
45' Concrete or Metal, direct buried		14.71	15.71
25' Concrete or Metal, Post Top, direct buried		6.69	7.05
Underground Wiring (per run)			
All sizes and types of fixtures		$15.34	$16.38

NEWFOUNDLAND POWER INC.
Proposed Changes to the Rate Stabilization Clause

It is proposed that Clause II.3 of the Rate Stabilization Clause be replaced with the following:

3. The annual kilowatt-hours used in calculating the Rate Stabilization Adjustment to the monthly streetlighting rates are as follows:

	Fixture Size (watts)			
	100	150	250	400
High Pressure Sodium	454	714	1,260	1,953

	Fixture Category			
	LED 100	LED 150	LED 250	LED 400
Light Emitting Diode	218	290	475	664