DELIVERED BY HAND

December 19, 2016

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: Net Metering Service Option Application

Enclosed please find the original and 12 copies of an application and supporting evidence seeking the Board's approval of a net metering service option for Newfoundland Power's customers.

In July 2015, the Government of Newfoundland and Labrador (the "Government") released a Net Metering Policy Framework (the "Framework"). The Framework was developed by the Government in consultation with stakeholders, including Newfoundland Power.

In Newfoundland Power's view, the Application proposes a reasonable net metering service regime for customers which is broadly consistent with the Framework and current sound public utility practice in North America.

A copy of this letter, together with the enclosures, has been forwarded directly to Tracey Pennell, Newfoundland and Labrador Hydro; and Dennis Browne, QC, Consumer Advocate. A copy has also been forwarded to the Department of Natural Resources, the authors of the Framework.

We trust the foregoing and enclosed are found to be in order.

Newfoundland Power Inc.
55 Kenmount Road • P.O. Box 8910 • St. John's, NL A1B 3P6
PHONE (709) 737-5859 • FAX (709) 737-2974 • **palteen@newfoundlandpower.com**

If you have any questions, feel free to contact us.

Yours very truly,

Peter Alteen, QC
Vice President,
Regulation & Planning

Enclosures

c. Tracey Pennell
Senior Counsel, Regulatory
Newfoundland & Labrador Hydro

Walter Parsons, P. Eng.
Assistant Deputy Minister, Energy Policy
Department of Natural Resources

Dennis Browne, QC
Consumer Advocate
Browne Fitzgerald Morgan & Avis

IN THE MATTER OF the
Public Utilities Act, (the "Act"); and

IN THE MATTER OF an application
by Newfoundland Power Inc. ("Newfoundland
Power") to approve a net metering
service option for customers.

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

THE APPLICATION OF Newfoundland Power **SAYS:**

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. In July 2015, the Government of Newfoundland and Labrador published a net metering policy framework aimed at providing utility customers with the option to offset their own energy usage through small-scale customer owned renewable generation (the "Framework"). Newfoundland Power has developed a net metering service option for its customers based upon the principles contained in the Framework (the "Net Metering Service Option").

3. The Net Metering Service Option is set out in the (i) rates, tolls and charges and (ii) rules and regulations in Schedule A to this Application.

4. The Net Metering Service Option:

   (a) is consistent with generally accepted sound public utility practice;

   (b) permits the management of all sources and facilities for the production, transmission and distribution of power in the province in manner consistent with the least cost, reliable delivery of service to customers; and

   (c) is reasonable and not unjustly discriminatory;

   all as required by sections 3 and 4 of the *Electrical Power Control Act, 1994* and more fully described in the evidence filed in support of this Application.

5. Newfoundland Power requests an Order from the Board approving the (i) rates, tolls and charges and (ii) rules and regulations in Schedule A to this Application to permit implementation of the Net Metering Service Option as described in the evidence filed in support of this Application.

6. Communication with respect to this Application should be forwarded to the attention of Peter Alteen, QC and Gerard M. Hayes, Counsel to Newfoundland Power.

DATED at St. John's, Newfoundland and Labrador, this 19th day of December, 2016.

NEWFOUNDLAND POWER INC.

Peter Alteen, QC and Gerard M. Hayes
Counsel to Newfoundland Power Inc.
P.O. Box 8910
55 Kenmount Road
St. John's, NL A1B 3P6

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IN THE MATTER OF the
Public Utilities Act, (the "Act"); and

IN THE MATTER OF an application
by Newfoundland Power Inc. ("Newfoundland
Power") to approve a net metering
service option for customers.

AFFIDAVIT

I, Lorne Henderson, Professional Engineer, of St. John's in the Province of Newfoundland and Labrador, make oath and say as follows:

1. That I am Director of Supply and Planning at Newfoundland Power Inc.

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

SWORN to before me at St. John's
in the Province of Newfoundland and
Labrador this 19th day of December, 2016:

Barrister

Lorne Henderson

NEWFOUNDLAND POWER INC.

SCHEDULE

OF

RATES, RULES AND REGULATIONS

Effective •

NEWFOUNDLAND POWER INC.

RATES, RULES AND REGULATIONS

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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.

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(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.

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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.

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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.

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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.

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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.

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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.

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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.

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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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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:

$$\frac{B + C}{D}$$

Where:

B = 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.

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:

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

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 streetlighting rates are as follows:

	Fixture Size (watts)				
	100	150	175	250	400
Mercury Vapour	-	-	840	1,189	1,869
High Pressure Sodium	454	714	-	1,260	1,953

4. On December 31, 2015, 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 interim wholesale rate change, effective July 1, 2015, 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 on an interim basis by Hydro effective July 1, 2015.

   This clause will be revised as required when the Company's rates are changed to reflect the flow-through of final changes to Hydro's wholesale rate.

   The methodology to calculate the RSA adjustment at December 31, 2015 is as follows:

Calculation of increase in Revenue:	
2015 Revenue with Flow-through (Q)	$ -
2015 Revenue without Flow-through (R)	$ -
Increase in Revenue (S = Q – R)	$ -
Calculation of increase in Purchased Power Expense:	
2015 Purchased Power Expense with Hydro Increase (T)	$ -
2015 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, 2015.
   R = Normalized revenue from base rates determined based on rates effective July 1, 2013.
   T = Normalized purchased power expense from Hydro's wholesale rate effective July 1, 2015 (not including RSP rate).
   U = Normalized purchased power expense determined based on Hydro's wholesale rate effective January 1, 2007 (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 (other than the energy charge in the "Maximum Monthly Charge" in classifications having a demand charge) 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.

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 .... $15.99 per month
Exceeding 200 Amp Service .... $20.99 per month

Energy Charge:
All kilowatt-hours .... @9.719¢ per kWh

Minimum Monthly Charge:
Not Exceeding 200 Amp Service .... $15.99 per month
Exceeding 200 Amp Service .... $20.99 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 ....$17.14 per month
Single Phase..$21.14 per month
Three phase...$27.14 per month

Demand Charge:
$9.19 per kW of billing demand in the months of December, January, February and March and $6.69 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 .... @ 9.622¢ per kWh
All excess kilowatt-hours .... @ 6.848¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 19.002 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 .... $17.14 per month
Single Phase .... $21.14 per month
Three Phase .... $33.14 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: .... $49.44 per month

Demand Charge:
$7.77 per kVA of billing demand in the months of December, January, February and March and $5.27 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 .... @ 7.995¢ per kWh
All excess kilowatt-hours .... @ 6.150¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 19.002 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: .... $86.15 per month

Demand Charge:
$7.47 per kVA of billing demand in the months of December, January, February and March and $4.97 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 .... @ 7.666¢ per kWh
All excess kilowatt-hours .... @ 6.082¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 19.002 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)	$16.78	$18.15
150W (14,400 lumens)	20.51	-
250W (23,200 lumens)	28.19	-
400W (45,000 lumens)	38.41	-

Special poles used exclusively for lighting service**

Wood	$6.27
30' Concrete or Metal, direct buried	8.96
45' Concrete or Metal, direct buried	14.67
25' Concrete or Metal, Post Top, direct buried	6.67

Underground Wiring (per run)**

All sizes and types of fixtures	$15.30

** 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 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, #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 un-metered 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, #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, #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, #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.

2016 Net Metering Service Option Application

Evidence of
Newfoundland Power Inc.

December 2016

WHENEVER. WHEREVER.
We'll be there.

Page

A. OVERVIEW

This Application seeks approval of a net metering service option to be offered to Newfoundland Power's customers.

Net metering programs to facilitate the interconnection of customer-owned generating resources to utility-owned networks have existed in some North American jurisdictions for over 30 years. Currently, interconnection of these customer-owned generating resources is typically justified by the promotion of renewable energy sources and/or the provision of the opportunity for customers to offset energy supply from the local utility. Approximately 90% of American states and Canadian provinces offer net metering service to utility customers.

Approximately a decade of Canadian utility experience indicates that the amount of energy provided to utilities by customer-owned generating resources tends to grow modestly over time. However, even for Canadian net metering programs which have existed for 10 years or more, total customer energy supplied to the utility remains relatively low, typically around $\frac{1}{10}$ of 1% of total utility load.

The net metering service option proposed in this Application is consistent with generally accepted sound public utility practice required to be applied by the Board by Section 4 of the *Electrical Power Control Act, 1994*. It also broadly conforms to a policy framework released in July 2015 by the Government of Newfoundland and Labrador. Amongst other things, this policy framework and supporting regulations limit the total amount of net metered customer generation to 5 MW. This is less than $\frac{1}{2}$ of 1% of Newfoundland Power's existing load.

The net metering service option proposed in this Application will oblige Newfoundland Power to pay (or provide a credit) for net energy supplied from customer-owned generating resources once in each year. This payment (or credit) will be based on the 2^{nd} block energy charge of the Newfoundland and Labrador Hydro Utility Rate applicable to wholesale supply for Newfoundland Power. So, the option will be consistent with the least cost provision of service to Newfoundland Power's customers.

The net metering service option proposed in this Application is not expected to have a material impact on the price of electricity for customers who do not avail of the option. So, the option will not result in unjust rate discrimination resulting from cross subsidization of one group of customers by another.

Canadian experience, together with the 5 MW limit for total net metered customer-owned generating resources, supports the conclusion that no material cost risks are associated with the net metering service option proposed in this Application. This includes any cost risk to those customers that do not avail of the option. For these reasons, the net metering service option proposed in this Application meets the requirements of Section 3 of the *Electrical Power Control Act, 1994* that utility service be provided in a least cost manner and utility rates be reasonable and not unjustly discriminatory.

The completion of the interconnection of Muskrat Falls to the Island Interconnected system is expected to have material impacts on electrical system costs and customer prices. Following the interconnection of Muskrat Falls, Newfoundland Power intends to revisit pricing associated with the net metering service option proposed in this Application. Such a course is consistent with Newfoundland Power's approach to other aspects of utility service likely to be affected by the interconnection of Muskrat Falls, such as conservation programming.

To permit implementation of the net metering service option proposed in this Application, some incidental changes to Newfoundland Power's General Service Rates will be required. Newfoundland Power expects to be in a position to fully implement the net metering service option proposed in this Application within 3 months of Board approval.

B. BACKGROUND

B.1 Origins of Net Metering Service

Net metering is almost exclusively associated with customer-owned, or distributed, electrical generating resources.[1]

Net metering records the electricity flows between the customer-owned generating resources and the utility-owned electrical system.[2] For customers who do not operate their own electrical generating resources, electricity flows are one way; from the utility's to the customer's electrical system. For customers who do operate their own electrical generating resources, the electricity flows can be bi-directional. Net metering regimes permit the orderly recording and billing of bi-directional electricity flows associated with customer-owned generating resources.

Net metering policies in North America originate with the implementation of the U.S. *Public Utilities Regulatory Policies Act* ("PURPA").[3] PURPA encouraged smaller distribution system level generating resources. To accommodate the development of these resources, a number of American states adopted policies allowing generation interconnection and utility purchase of electricity from small generators in the early

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1 Distributed generation resources are electrical generators located on the distribution grid. These resources are considered *distributed* because they are distributed across an electrical system service territory as opposed to being centralized.

2 Generally, public utilities are responsible for the operation of electrical systems up to and including the meter which records service delivery to a customer. The customer is generally responsible for the electrical system beyond the metering point.

3 See *Public Utility Regulatory Policies Act*, Pub.L. 95-617, November 9, 1978, 92 Stat. 3117.

1980s.[4] The adoption of net metering in the U.S. extended into the 1990s and beyond as a result of implementation of the U.S. *Energy Policy Act of 1992* and *Energy Policy Act of 2005*, both of which further promoted small scale generation.[5] The *Energy Policy Act of 2005* required all public electric utilities to offer net metering.[6] By 2015, 46 U.S. states and the District of Columbia had one or more utilities offering net metering service.[7]

In Canada, net metering policies were adopted in most provinces in the 2004 to 2009 period.[8] The only Canadian province in which net metering service is not available to utility customers is Newfoundland & Labrador.

B.2 The Navigant Study

The Newfoundland & Labrador Department of Natural Resources retained Navigant Consulting Ltd. to review public utility practice to inform the consideration and

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4 Among the earliest adopters of utility-specific or state wide net metering policies were the Idaho Public Service Commission, Arizona Corporation Commission and Massachusetts Department of Public Utilities which adopted policies in the early 1980s. The Minnesota legislature is often cited as enacting the first state wide net metering policy. See *Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers*, Acadian Consulting Group, Draft Report, February 27, 2015, prepared on behalf of Louisiana Public Service Commission.

5 See *Energy Policy Act*, Pub.L. 102-486, October 24, 1992, 106 Stat. 2776 and *Energy Policy Act*, Pub.L. 109-58, August 8, 2005, 119 Stat. 594.

6 See Exhibit 1, *Net Metering Standard Industry Practices Study*, Navigant Consulting Ltd., October 31, 2014, prepared on behalf of the Department of Natural Resources, Government of Newfoundland & Labrador, page 6.

7 See *Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers*, Acadian Consulting Group, Draft Report, February 27, 2015, prepared on behalf of Louisiana Public Service Commission.

8 See Exhibit 1, *Net Metering Standard Industry Practices Study*, Navigant Consulting Ltd., page 29.

development of a net metering policy framework for the province.[9] The report from this review by Navigant Consulting Ltd. (the "Navigant Study") is Exhibit 1 to this evidence.[10]

The Navigant Study reviewed utility industry practices in all Canadian and select American jurisdictions. The practices examined included (i) customer eligibility criteria, (ii) overall subscription limits for customer generation, (iii) settlement of excess customer generation credits, (iv) technical connection requirements, and (v) utility recovery of connection costs.

The Navigant Study showed significant consistencies in many aspects of current public utility practice related to net metering.

Industry practice indicates that net metering is typically limited to renewable sources of generation owned by residential and small business customers. These sources are typically small scale. Capacity limits in the 9 Canadian provinces currently offering net metering service range from 50 kW to 1 MW, with 5 provinces establishing a capacity limit for residential and small commercial customer installations of 100 kWs. Similarly, overall subscription limits are generally less than 2% of total system capacity, with 1% being the most common standard.[11]

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9 Newfoundland Power's Lorne Henderson, P. Eng., was a member of the steering committee which oversaw this review by Navigant Consulting Ltd.

10 The Navigant Study was completed October 31, 2014. Prior to filing this Application, Newfoundland Power surveyed Canadian provinces to confirm that the results reflected in the Navigant Study have not changed materially.

11 Currently, British Columbia, New Brunswick, Nova Scotia, Prince Edward Island and Saskatchewan all have an established capacity limit of 100 kW for residential and small commercial customers. See Exhibit 1, *Net Metering Standard Industry Practices Study*, Navigant Consulting Ltd., pages 16-18.

The Navigant Study shows that in all jurisdictions reviewed, the energy supplied to the utility from customer-owned generating resources is netted against the energy supplied by the utility to the customer in monthly billing.[12] This effectively results in the energy supplied from the customer-owned generating resources being valued at tariffed rates in monthly bills.

In certain months, a customer may supply electrical energy to the utility which exceeds the amount of electrical energy which the utility has provided to that customer during that month. Typically, this excess is considered as credits which the customer may use to offset energy purchases from the utility in future months.[13] After a specified period, typically a year, the credits associated with this excess customer supply are settled. The Navigant Study indicated that about half of the jurisdictions in Canada offer customers a cash payment to settle the liability associated with the excess generation credits at the end of this period.[14]

The Navigant Study also indicated that utilities address the technical and safety issues arising from connecting customer-owned generating resources to the distribution system through a customer application and evaluation process.[15] Similarly, in all jurisdictions reviewed, customers are typically responsible for paying the additional

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[12] See Exhibit 1, *Net Metering Standard Industry Practices Study*, Navigant Consulting Ltd., page 26 where it is observed that "In all of the jurisdictions reviewed, NM [net metering] customers are billed…volumetric charges based on the net volume of electricity consumed."

[13] See Exhibit 1, *Net Metering Standard Industry Practices Study*, Navigant Consulting Ltd., page 26.

[14] See Exhibit 1, *Net Metering Standard Industry Practices Study*, Navigant Consulting Ltd., page 28. Other jurisdictions zero out any remaining credits.

[15] See Exhibit 1, *Net Metering Standard Industry Practices Study*, Navigant Consulting Ltd., pages 19-20.

costs associated with net metering installations while the utility absorbs any additional costs of meter reading, billing and administration associated with the review and approval process.[16]

B.3 Newfoundland and Labrador Policy Framework

In July 2015, the Government of Newfoundland and Labrador (the "Government") released a Net Metering Policy Framework (the "Framework"). The Framework, developed in consultation with Newfoundland Power and Newfoundland and Labrador Hydro, was supported by the findings of the Navigant Report. Government also consulted with stakeholders to solicit their input. The Framework is Exhibit 2 to this evidence.

The Government's policy objective reflects the province's existing and forecast generation mix. The Framework states the policy objective as follows:

> "…the primary driver for a net metering policy in Newfoundland and Labrador is not to encourage the development of renewable energy, but to provide customers with the option to offset their own energy usage through small-scale renewable generation they develop themselves."[17]

The Framework states that the current energy supply outlook for Newfoundland and Labrador indicates that 98% of the provincial energy supply will be renewable resources

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16 See Exhibit 1, *Net Metering Standard Industry Practices Study*, Navigant Consulting Ltd., page 28. The additional cost of meter reading, billing and administration are not expected to be material. For example, in 2013, BC Hydro reported their total expenditure on technical review of designs was $2,000 (see page 20).

17 See Exhibit 2, *Government of Newfoundland & Labrador Net Metering Policy Framework*, page 2.

following the interconnection of Nalcor Energy's Muskrat Falls hydroelectric plant. Given this, the Framework's policy focus on the provision of the opportunity for customers to offset energy supply from local utility providers (as opposed to the promotion of renewable energy development) seems justified.

The Framework provides policy parameters to guide utility design of net metering programs. The Framework, however, contemplates a significant degree of flexibility and discretion to a utility in a number of critical areas of net metering service design. This includes (i) customer eligibility criteria, (ii) technical connection requirements and (iii) utility recovery of connection costs.[18] The utilities will also have discretion to review customer connection requests and to limit both the number of net metering customers and the size of the proposed customer generation.

The Framework recognizes the Board's regulatory jurisdiction over any Newfoundland Power net metering service option. All rules developed by utilities with respect to net metering are required to be consistent with the *Public Utilities Act* and the *Electrical Power Control Act, 1994*.[19] Any net metering service option proposed by Newfoundland Power under the Framework is recognized to be subject to Board approval prior to implementation.[20] The Framework provides for ongoing monitoring and evaluation of

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[18] See Exhibit 2, pages 3-5.

[19] See Exhibit 2, Section 4.0: *ROLES AND RESPONSIBILITIES*, pages 6-7. The *Public Utilities Act* and the *Electrical Power Control Act, 1994* are the legislative cornerstones of utility regulation in the province. By contrast, the Framework is a statement of Government policy. To the degree Government policy conflicts with legislation, Newfoundland Power considers the legislation to be paramount.

[20] See Exhibit 2, Section 3.8: *Regulatory Treatment*, page 6.

any net metering service option provided by Newfoundland Power to its customers.[21] Continuing regulatory oversight of net metering service provided by a utility appears consistent with sound public utility practice.[22]

The Framework is supported by the *Net Metering Exemption Order* made under the *Electrical Power Control Act, 1994*.[23] The *Net Metering Exemption Order* effectively exempts Newfoundland Power from the provisions of Section 14.1 of the *Electrical Power Control Act, 1994* for customer generating facilities of 100 kW or less up to a system total limit of 5 MW.[24]

The *Net Metering Exemption Order* also effectively restricts the application of any net metering service option made available by Newfoundland Power to its customers to (i) facilities of 100 kW or less and (ii) a system limit of 5 MW of generating facilities. These restrictions appear broadly consistent with existing Canadian public utility practice.[25]

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21 See Exhibit 2, Section 5.0: *MONITORING AND EVALUATION*, pages 6-7. In addition, any net metering service option would be subject to the Board's continuing supervisory powers under Section 16 of the *Public Utilities Act*.

22 See Alberta Regulation 27/2008 as amended by Alberta Regulation 203/2015 and Arizona Corporation Commission Docket No. E-00000J-14-0023 in the matter of the Commission's Investigation of Value and Cost of Distributed Generation.

23 See Newfoundland and Labrador Regulation 47/15, filed July 28, 2015.

24 Section 14.1 of the *Electrical Power Control Act, 1994* effectively prohibits Newfoundland Power from purchasing generation resources from any supplier other than Newfoundland and Labrador Hydro.

25 The Navigant Study indicated that the most common Canadian net metering policy capacity limit for small scale customer-owned generation was 100 kW. In addition, the Navigant Study indicated that the most common overall Canadian subscription limit was 1% of total system capacity. See Exhibit 1, *Net Metering Standard Industry Practices Study*, Navigant Consulting Ltd., Table 2: Capacity Limits by Jurisdiction, page 17 and Table 3: Annual Uptake Rates, page 29. 5 MW represents less than ½ of 1% of Newfoundland Power's annual peak and approximately ¼ of 1% of island interconnected system capacity.

C. NEWFOUNDLAND POWER'S NET METERING SERVICE OPTION

C.1 The Net Metering Service Option

Newfoundland Power's net metering service option (the "Net Metering Service Option") is set out in Schedule A to this Application. Exhibit 3 is a copy of Schedule A with changes indicated by yellow shading [].

The Net Metering Service Option is available to customers served under all of Newfoundland Power's metered rate service classes. It provides customers with the opportunity to reduce the amount of energy purchased from Newfoundland Power. For unmetered service such as that provided under *Rate # 4.1: Street and Area Lighting Service*, net metering is not possible due to the absence of a meter.[26]

To be served under the Net Metering Service Option, a customer must own and maintain responsibility for its generating facilities and interconnection to Newfoundland Power's electrical system. A customer's generating facilities must produce electricity from renewable energy sources and must be sized to not exceed (i) the energy requirements of the customer's premises or (ii) 100 kW capacity.[27] A customer's generating facilities are required to meet specified technical standards including the *Canadian Electrical Code*.

[26] Similarly, net metering will not be available to unmetered service provided to approximately 1,800 facilities such as traffic lights, crosswalks and telecom power supplies. These services have energy consumption which is relatively low and constant and can readily be determined without metering as permitted by Section 2(c) of the Company's Rules and Regulations.

[27] The 100 kW capacity limit is required by the *Net Metering Exemption Order.* The requirement that the customer's generation not exceed the annual energy requirements of the customer's premises is consistent with the overall policy objective of the Framework that net metering "……..provide customers with the option to *offset their own energy usage* through small-scale renewable generation they developed themselves" (italics added).

A customer must apply and receive approval from Newfoundland Power in order to avail of the Net Metering Service Option. The customer application will provide Newfoundland Power the information necessary to reasonably assess (i) the customer's proposed generating facilities, including technical features and interconnection requirements, and (ii) any required modifications to Newfoundland Power's electrical system to permit interconnection and operation of the customer's generating facilities. A customer served under the Net Metering Option is responsible for any Newfoundland Power costs required to permit the customer to interconnect to the electrical system.[28] Newfoundland Power will approve a customer's application where it complies with the Net Metering Service Option requirements.

Customers served under the Net Metering Service Option will receive monthly bills which indicate (i) the energy supplied by Newfoundland Power to the customer and (ii) the energy supplied by the customer's generating facilities to Newfoundland Power. Each monthly bill will net the charge for energy supplied by Newfoundland Power to the customer (together with HST) with the credit for energy supplied by the customer to Newfoundland Power (together with HST, if applicable) to determine the customer's

[28] By way of example, Newfoundland Power might incur additional transformation or metering costs to permit a customer served under the Net Metering Service Option to interconnect to the electrical system.

monthly bill.[29] Customer billing of energy charges in this manner is a consistent feature of net metering regimes across North America.[30]

Except for the elimination of the Maximum Monthly Charge in General Service Rates #2.1, 2.3, and 2.4 for customers served under the Net Metering Service Option, existing customer and demand charges will not be changed.[31]

Where a customer served under the Net Metering Service Option supplies more energy to Newfoundland Power than it receives from Newfoundland Power in a particular month, the amount of excess energy, in kWhs, supplied by the customer becomes energy credits. These energy credits are banked and applied to future monthly bills of the customer to offset energy supplied by Newfoundland Power.

Once a year, all banked energy credits of a customer participating in the Net Metering Service Option are required to be settled with either a cash payment or a bill credit.[32] The amount of this payment or credit is based upon the then current 2nd block energy

[29] All energy supplied by Newfoundland Power to the customer is subject to Harmonized Sales Tax ("HST") under the federal *Excise Tax Act*. Energy supplied by a customer to Newfoundland Power may also be subject to HST depending on whether the customer is an HST registrant. The *Excise Tax Act* requires HST registration when a person's or entity's total taxable supply exceeds $30,000 in value within four consecutive quarters. A person may also voluntarily register to be a HST registrant.

[30] The Navigant Study indicates that, in *all* jurisdictions reviewed, net metering customers' monthly bills are based on their net electricity consumption. (emphasis added) See Exhibit 1, *Net Metering Standard Industry Practices Study*, Navigant Consulting Ltd., page 26.

[31] The justification for eliminating the Maximum Monthly Charge in Rates #2.1, 2.3, and 2.4 for customers served under the Net Metering Service Option is provided under Section C.3: Implementation Details.

[32] Annual settlement of unused generation credits is the practice in most jurisdictions surveyed in the Navigant Study. See Exhibit 1, *Net Metering Standard Industry Practices Study*, Navigant Consulting Ltd., page 28.

charge for Newfoundland and Labrador Hydro's Utility Rate applicable to service provided to Newfoundland Power.[33]

C.2 Customer Participation

The number of Newfoundland Power customers that will avail of the Net Metering Service Option is currently uncertain.[34] Utility experience indicates that customer take-up of net metering programs tends to be low at the point of program introduction and develop gradually.[35]

The *Net Metering Exemption Order* restricts the application of net metering in the province to a total of 5 MW.[36] This represents less than $\frac{1}{2}$ of 1% of Newfoundland Power's 2015-16 peak load.[37] The Navigant Study has indicated relatively low customer uptake as a percentage of installed capacity, typically about $\frac{1}{10}$ of 1% in Canadian jurisdictions.[38]

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33 The justification for use of the current 2nd block energy charge for Newfoundland and Labrador Hydro's Utility Rate applicable to service provided to Newfoundland Power is provided under Section D.3: Annual Settlement of Credits.

34 Since 2013, Newfoundland Power has recorded over 60 customer inquiries related to net metering issues. In addition, a small number of business related inquiries have been received.

35 For example, Nova Scotia Power ("NSP") has had a net metering regime since 2005. As of December 31, 2015, NSP had a total of 234 installed net metered customer generation units with a total capacity of 1.7 MW or approximately $\frac{1}{10}$ of 1% of 2015 peak demand of 1,825 MW (1.7 / 1,825 = 0.001). NSP's number of annual additions have been highly variable but have tended to increase over time. In 2007, 9 customers availed of NSP's net metering option; in 2011, an additional 17 customers took up the option; and in 2015, an additional 43 customers took up the option. See NSP *Regulation 3.6-2015 Net Metering Report* filed January 27, 2016.

36 *Net Metering Exemption Order*, Section 5(2).

37 Newfoundland Power's 2015-16 peak load was 1,381 MW (5 / 1,381 = 0.004). Because the *Net Metering Exemption Order* is province wide, the 5 MW limit presents an even lower proportion of total provincial peak load.

38 See Exhibit 1, *Net Metering Standard Industry Practices Study*, Navigant Consulting Ltd., page 29, Table 3.

Based upon data contained in the Navigant Study, customer-owned generation installations in the range of 5 kW to 7.5 kW are typical.[39] Based upon these sizes of customer installations, the maximum number of customers that could avail of the Net Metering Service Option under a 5 MW cap would be in the range of 667 to 1,000 customers.[40]

Utility experience with net metering regimes indicates that customer take-up of Newfoundland Power's Net Metering Service Option should ramp up over a number of years and not approach the maximum aggregate of 5 MW for some time. This will permit Newfoundland Power reasonable opportunity to monitor and assess actual experience with the Net Metering Service Option with a view to ensuring it continues to be consistent with sound public utility practice.[41]

C.3 Implementation Details

C.3.1 Incidental Changes to General Service Rates

Newfoundland Power's General Service Rates # 2.1, 2.3 and 2.4 each provides for demand charges and a maximum monthly charge for customers with demands of 10 kW

[39] See Exhibit 1, *Net Metering Standard Industry Practices Study*, Navigant Consulting Ltd., page 37 and page 40 which indicates average site installation of approximately 5 kW in British Columbia (1.138 MW / 228 = 4.99 kW) and approximately 7.3 kW in Nova Scotia (1.152 MW / 157 = 7.34 kW).

[40] Both NSP and BC Hydro are significantly larger utilities than Newfoundland Power and have had net metering regimes in place for over 10 years. NSP reported 234 installed net metered customer generation units in 2015 (see Footnote 35) and BC Hydro reported 228 net metered customer generation units in 2013 (see Exhibit 1, page 37).

[41] Continuing monitoring and evaluation of the Net Metering Service Option is contemplated by the Framework (see Section 4.0: *ROLES AND RESPONSIBILITIES*, page 6 *et. seq*.)

or greater. The maximum monthly charge exists to ensure that customers with low load factors pay a reduced amount of demand related costs.[42]

It is appropriate to eliminate the maximum monthly charge for customers availing of the Net Metering Service Option. Some customers with generating facilities interconnected to Newfoundland Power's electrical system may have monthly bills with low net energy usage but still have used the Company's system to meet its full peak demand requirement in the month. For such customers, it is fair that they pay the costs of the capacity used in the month and not an amount limited by application of the maximum monthly charge.[43]

Elimination of the maximum monthly charge for customers availing of the Net Metering Service Option reduces risks of cost subsidization arising from shifting demand cost recovery between customers in General Service Rates # 2.1, 2.3 and 2.4.

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[42] Load factor is a measure of a customer's energy use relative to peak demand. A low load factor customer uses a relatively small amount of energy relative to peak demand; this is common for facilities that are sporadically or occasionally used. The maximum monthly charge, in effect, limits the amount of demand costs that low load factor customers with peak demands of 10 kW or greater are required to pay. The limitation is based on low load factor customers being less coincident with system peak.

[43] For example, a customer with generating facilities that operate for ½ of a month and fully satisfy the owner's energy requirements for that portion of the month may still rely on Newfoundland Power's electrical system to satisfy its energy and demand requirements for the remainder of the month but have a net energy supply from Newfoundland Power of 0 kWhs. Because this customer relied on Newfoundland Power's electrical system to satisfy its demand requirement for a significant portion of the month, it is appropriate that the customer pay full demand charges for the month and not a reduced amount by reason of operation of the maximum monthly charge.

C.3.2 Implementation Timing

Newfoundland Power expects to be in a position to fully implement the Net Metering Service Option within 3 months of Board approval. The principal tasks associated with implementation include (i) metering and billing modifications, (ii) customer service training and (iii) website modifications to support customer self-service.

This 3-month implementation period is not expected to meaningfully delay customers in availing of the option. Newfoundland Power expects to be in a position to make the Net Metering Service Option application form available within 2 weeks of Board approval.

D. RATES & COST ANALYSES

D.1 Rates Analysis

Monthly bills for customers served under the Net Metering Service Option will effectively reflect credit for (or net) energy supplied to Newfoundland Power based upon the Company's customer rates as approved by the Board.[44]

Table 1 shows Newfoundland Power's current customer energy rates for metered service by rate class.

Table 1
Customer Energy Rates
Metered Service

Rate Class	Rate Code	Energy Rates (¢/kWh)
Domestic Service	1.1	9.719[45]
General Service 0-100 kW (110 kVA)	2.1	6.848 – 9.622[46]
General Service 110-1000 kVA	2.3	6.150 – 7.995[46]
General Service 1000 kVA and Over	2.4	6.082 – 7.666[46]

Newfoundland Power's current customer energy rates range from 6.1 ¢/kWh to 9.7 ¢/kWh.

[44] As indicated at page 13, lines 1-2 and Footnote 30, the netting of customer energy supply from utility energy supply is a consistent feature of net metering regimes in North America.
[45] For Domestic customers served under the Seasonal Option, the energy rate varies from 8.422 ¢/kWh (May – November) to 10.672 ¢/kWh (December – April).
[46] For General Service rates, the lower value represents excess energy rates and the higher value represents 1st block energy rates.

Currently, Hydro charges Newfoundland Power 9.509 ¢/kWh for wholesale marginal energy supply.[47] This is found in the 2nd block energy charge in Hydro's Utility Rate.[48]

Based upon current rates, the difference between (i) the credit to customers (at current customer energy rates) and (ii) the wholesale marginal energy rate for Newfoundland Power purchases from Hydro ranges from -3.4 ¢/kWh to +0.2 ¢/kWh.

D.2 System Cost Analysis

The cost of fuel for Hydro's Holyrood Thermal Generating Station ("Holyrood") has been accepted by the Board as a reasonable proxy for marginal system energy costs for the Island Interconnected system.[49] Based upon Hydro's current 2017 fuel forecast, the cost of Holyrood fuel is approximately 10.947 ¢/kWh.[50]

The cost impact for the Island Interconnected system from monthly bill credits to customers served under the Net Metering Service Option is the difference between (i) the credit to customers (at current customer energy rates) and (ii) the marginal system energy cost. Based upon current rates and marginal system energy costs, this

[47] See Order No. P.U. 17 (2015) which established Hydro's current interim Utility Rate.

[48] Hydro's Utility Rate to Newfoundland Power for firm service includes a demand charge and a 2 block energy charge. The demand charge reflects the marginal cost of capacity. The 2nd block energy charge reflects the marginal cost of energy. The 1st block energy charge, in effect, is used to reconcile Hydro's total cost to serve Newfoundland Power with the associated revenue requirement.

[49] Avoided Holyrood fuel costs are used to establish end block energy prices for Hydro's Utility Rate and as a reference in Newfoundland Power's customer rates. In addition, avoided Holyrood fuel costs are used in economic analysis to support capital investment, including Newfoundland Power hydroelectric plant refurbishment projects.

[50] See Hydro's correspondence of October 14, 2016 which provides its fuel cost projection of $67.65 a barrel for No. 6 fuel. The cost of 10.947 ¢/kWh reflects this fuel cost and conversion efficiency of 618 kWh/bbl. Accepted by the Board in Order No. P.U. 49 (2016).

difference ranges from 1.2 ¢/kWh to 4.9 ¢/kWh less than the current forecast of cost of fuel at Holyrood.

This indicates that, at current rates and marginal system energy costs, the Net Metering Service Option would contribute to *lower* overall costs on the Island Interconnected system. The cost of fuel at Holyrood can be expected to vary prior to the interconnection of Muskrat Falls, however, recent estimates have been relatively stable.[51]

When system marginal energy costs exceed Newfoundland Power's customer energy rates as they currently do, the Net Metering Service Option will serve to reduce overall system costs. Given the low expected volumes of energy involved, this is unlikely to result in any material rate reduction. An assessment of impacts where system marginal energy costs are lower than Newfoundland Power's customer energy rates indicates that any rate impacts would similarly not be material.[52]

Recent Holyrood fuel cost forecasts indicate that the Net Metering Service Option should tend to lower overall energy supply costs on the Island Interconnected system.

[51] At the time of filing Newfoundland Power's *2016 Capital Budget Application*, the cost of fuel at Holyrood was estimated to be 11.6 ¢/kWh and at the time of filing Newfoundland Power's *2017 Capital Budget Application*, the cost of fuel at Holyrood was estimated to be 8.7 ¢/kWh. Both of these values were derived using a conversion rate of 630 kWh/bbl. at Holyrood.

[52] Newfoundland Power considered the potential increased cost of the Net Metering Service Option to non-participating customers across a range of assumptions. The most conservative assumption (no avoided utility supply costs associated with the customer supplied energy) yielded net cost impacts to non-participants of approximately $\frac{1}{10}$ of 1%.

A substantial reduction in fuel costs might alter this dynamic; however, such a material reduction in fuel costs is not currently forecast.[53]

D.3 Annual Settlement of Credits

At each annual review of a customer's participation in the Net Metering Service Option, all banked energy credits are required to be settled. Upon settlement, a customer is entitled to a cash payment or bill credit. The Net Metering Service Option provides that the cash payment or bill credit due to customers be based on the then current 2nd block energy charge for Hydro's Utility Rate.[54]

Using the 2nd block Utility Rate energy charge for annual settlement of banked energy credits under the Net Metering Service Option is consistent with both sound regulatory economics and rate administration. From the economic perspective, it will provide reasonable continuing assurance that the Net Metering Service Option continues to contribute to least cost service for *all* customers as required by the *Electrical Power*

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[53] In fact, energy forecasters appear to be predicting material *increases* in the price of fuels over the next 5 years. See U.S. Energy Information Administration *Annual Energy Outlook 2016*, dated May 2016. Material increases in fuel cost prior to the interconnection of Muskrat Falls would have the tendency to increase the system benefits associated with implementation of the Net Metering Service Option. In the event that the interconnection of the Island Interconnected system to the North America grid occurs prior to commissioning of Muskrat Falls, changes to marginal system energy costs are possible, however, the impact, if any, of such a development is uncertain and likely transitionary in nature.

[54] Use of a utility's avoided cost for annual settlement is consistent with current public utility practice (see Navigant Study, page 27). In Order No. G-26-04, the British Columbia Utilities Commission characterized the purchase of annual net excess generation based on avoided cost as a "*…fair and reasonable approach for valuing the excess generation from qualifying net metering facilities under BC Hydro's eligibility criteria, from the perspective of both participating and non-participating customers*."

Control Act, 1994.[55] From the rate administration perspective, use of a Board approved rate for settlement provides practical attributes of simplicity and understandability.[56]

Banked energy credits existing at each anniversary of a customer's participation in the Net Metering Service Option, in effect, represent energy purchases by Newfoundland Power over the year that were used to provide service to its customers. Like all utility expenditures, energy purchases are required to be reasonably consistent with the least cost principle.[57]

Current regulatory practice is to set the 2nd block of Hydro's Utility Rate energy charge to Newfoundland Power to reasonably reflect marginal energy costs on the Island Interconnected system. Using the 2nd block Utility Rate energy charge to settle banked energy credits on an annual basis ensures that, on a continuing basis, Newfoundland Power pays a reasonable approximation of system marginal energy costs for those credits. This is reasonably consistent with the least cost principle.

Use of the 2nd block Utility Rate energy charge is also consistent with sound rate administration. Hydro's Utility Rate is explicitly approved by the Board. The cost of fuel

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[55] The Framework indicates that customers are to be compensated for net excess generation at "retail rates" (see Framework, Section 3.4 iv). For the Board to approve the Net Metering Service Option, it requires reasonable evidence of compliance with regulatory legislation including the *Electrical Power Control Act, 1994*. Using the 2nd block Utility Rate energy charge, as opposed to retail rates, for the purposes of settling annual banked energy credits provides a reasonable assurance of continuing compliance with legislation in the event that retail rates and marginal system energy costs diverge.

[56] Practical-related attributes such as simplicity, certainty, understandability and feasibility of application are widely accepted as desirable in a sound utility rate structure. See, for example, *Principles of Public Utility Rates*, 2nd Edition, Public Utilities Reports, Inc., page 382, *et. seq.*

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

at Holyrood (and the impact on system marginal energy costs) is typically considered by the Board in the regulation of Hydro and Newfoundland Power, however, it is not explicitly approved by the Board in the manner that rates are. Use of rates explicitly approved by the Board is more consistent with understandable customer rate administration.

D.4 The Interconnection of Muskrat Falls

The interconnection of the Muskrat Falls hydroelectric plant to the Island Interconnected system is expected to materially change customer prices and electrical system costs.

It currently appears that customer rates following the interconnection of Muskrat Falls will be materially higher than they currently are. Public indications are that customer rates following the interconnection of Muskrat Falls could be as high as 21 ¢/kWh; however, rate mitigation options which might reduce customer rate impacts will be considered over the next few years.[58]

The interconnection of Muskrat Falls is expected to result in materially lower marginal system energy costs. In Hydro's February 2016 marginal cost study, marginal energy costs following the interconnection of Muskrat Falls were estimated to be as low as 4 ¢/kWh.[59] These estimates are subject to changes in energy market conditions in

[58] See Nalcor Energy News Release, *Nalcor Energy provides update on Muskrat Falls project*, June 24, 2016.

[59] See Marginal Cost Report, Part II, *Estimation: Marginal Costs of Generation and Transmission Services for 2019*, Christensen Associates Energy Consulting, February 26, 2019 (sic), filed with the Board February 26, 2016.

northeastern North America and delay in the forecast completion of Muskrat Falls and so are subject to change to reflect more current conditions following the interconnection.

The expected impacts on system cost and customer rates resulting from the interconnection of Muskrat Falls will justify a reexamination of the pricing associated with the Net Metering Service Option. A reexamination will not be feasible until the impacts are more fully known and evaluated. This is consistent with Newfoundland Power's approach to other aspects of utility service likely to be affected by the interconnection of Muskrat Falls, such as conservation programming.[60]

D.5 Regulatory Assessment

The Framework, together with the *Net Metering Exemption Order*, restricts the application of any Net Metering Service Option to a system total of 5 MW. This restricts the total customer take-up for the Net Metering Service Option to less than $\frac{1}{2}$ of 1% of Newfoundland Power's load. Low customer take-up of the Net Metering Service Option would also be consistent with the Canadian experience over the past decade.

A recognized regulatory hazard of net metering regimes is the potential for such regimes to result in undue cross subsidization whereby the majority of customers, in

[60] Newfoundland Power and Hydro's joint *Five-Year Conservation Plan: 2016-2020* indicated that significant changes in the electrical system resulting from the interconnection of Muskrat Falls might justify revision to program evaluation and the plan itself. See Newfoundland Power *2016/2017 General Rate Application*, Company Evidence, page 2-15, lines 12-15 and Report 1 - *Five-Year Conversation Plan: 2016-2020*, page 37. In Order No. P.U. 18 (2016), page 46, the Board indicated that it was satisfied that "…*Newfoundland Power's approach to conservation and demand management is appropriate and aligns with utility and customer interests*."

effect, subsidize customers that own generation.[61] The issue of when cross subsidization in utility rate design becomes *unjust*, or a matter of regulatory concern, is widely recognized as a matter of degree and regulatory judgment.[62] This fact of life in utility ratemaking underpins the Board's longstanding practice to permit Newfoundland Power's customer rates to be designed with revenue-to-cost ratios within a target range of 90% to 110%.[63]

Regulatory experience in jurisdictions where the number of net metered customers is relatively small indicates that any cross subsidization which does arise is not sufficient to be problematic. The National Association of Regulatory Utility Commissioners recently characterized the issue of cross subsidization in net metering regimes as follows:

> "At a low level of adoption, this may be considered merely another imperfection in rate design, but at large levels of adoption it can be problematic and represent large amounts of revenue being shifted to other, non-DER [distributed energy resources] customers in the same rate class."[64]

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[61] The potential for cross subsidization was identified in the Navigant Study as "…the most common regulatory concern…" associated with net metering policies. See The Navigant Study, page 20, *et. seq*.

[62] See, for example, *Distributed Energy Resources, Rate Design and Compensation: A Manual Prepared by the NARUC Staff Subcommittee on Rate Design*, November 2016, The National Association of Regulatory Utility Commissioners, Washington, DC, where it was observed that "Cross subsidies, subsidies from one group of ratepayers to another, are endemic in all utility ratemaking as there are variations in consumption patterns within rate classes that cause one part of a rate class to subsidize another part, as well as differences among classes due not only to differential use but also differential impacts of utility rates.", page 86.

[63] This practice originated in Order No. P.U. 7 (1996-97), where it was observed that "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%,…".

[64] *Distributed Energy Resources, Rate Design and Compensation: A Manual Prepared by the NARUC Staff Subcommittee on Rate Design*, November 2016, The National Association of Regulatory Utility Commissioners, Washington, DC, page 67.

The Navigant Study reached a similar conclusion.[65]

Newfoundland Power has assessed the overall potential rate impacts and risk of cross subsidization associated with the Net Metering Service Option in the context of current electrical system costs and customer rates. In Newfoundland Power's view, potential rate impacts will be immaterial largely due to the low volumes of energy involved. For similar reason, the potential for cross subsidization will be minimal and unlikely to result in unjust rate discrimination.

In addition, the use of the 2nd block Utility Rate energy charge (i.e., system marginal energy costs) to settle banked energy credits, provides further assurance that, once implemented, the Net Metering Service Option will not result in (i) a material change in customer rates, or (ii) undue rate discrimination by reason of cross subsidization.

The interconnection of the Muskrat Falls hydroelectric plant to the Island Interconnected system will materially affect electrical system costs and customer prices. This justifies a re-examination of pricing associated with Newfoundland Power's Net Metering Service Option following that interconnection.

[65] Navigant observed that "In most of the jurisdictions reviewed the potential financial impact on non-NM [net metering] customers is expected to be very small given the small number of NM customers and the limited amount of generation contributed to the system." See Exhibit 1, *Net Metering Standard Industry Practices Study*, Navigant Consulting Ltd., page 21.

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NET METERING STANDARD INDUSTRY PRACTICES STUDY

Prepared for:

Newfoundland Labrador

The Department of Natural Resources,
Government of Newfoundland & Labrador

October 31, 2014

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Executive Summary

The Newfoundland and Labrador (NL) Department of Natural Resources (DNR) retained Navigant to carry out a review of standard industry policies and practices with respect to net metering (NM) in Canada and internationally. The review is part of a commitment in the Provincial Government's 2007 Energy Plan: *Focusing Our Energy* to develop and implement a NM policy for small-scale renewable energy sources. Navigant worked with a Steering Committee comprised of members of the DNR and representatives of Newfoundland and Labrador Hydro (NLH) and Newfoundland Power (NP) who provided guidance for the review. The findings and considerations for a Net Metering (NM) policy presented in the report are Navigant's but were reviewed with the Steering Committee.

In its 2007 Energy Plan the Government of NL committed that it "*will ensure that regulatory support is in place for customers who wish to develop these alternatives themselves on a small scale, through a net metering policy*". Navigant has interpreted this focus on small scale, renewable sources and providing customers with access to connect to the utility grid as key in identifying appropriate elements for a NM policy for the Province.

NM policies allow customers with small generating facilities to generate power from renewable sources for their own use, feed power into the distribution system during periods when their generation provides power in excess of their needs, and to draw power from the grid at times when their generation does not fully meet their needs.

The NL system has one of the highest proportions of renewable hydraulic generation of any jurisdiction in North America[1]. The province's two utilities, Newfoundland Hydro (NLH) and Newfoundland Power (NP) are regulated by the Board of Commissioners of Public Utilities of Newfoundland & Labrador (PUB-NL) on a cost of service basis with a PUB-NL mandate to "*ensure that the rates charged are just and reasonable, and that the service provided is safe and reliable*"[2]. The power policy for the Province, as stated in the *Electrical Power Control Act*[3] includes requirements to ensure that electrical rates "*should be reasonable and not unjustly discriminatory*" and that the power system should be operated and managed in a manner "*that*

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[1] As indicated in the Introduction, NL anticipates that after Muskrat Falls and the associated transmission ties come on line the province will generate almost 100% of its electricity from renewable sources. In Canada and the US, only Manitoba (92%), Quebec (94%), BC (84%), Washington (79%) and Oregon (77%) come close to this level of renewable supply. (Bracketed figures represent the percentage of generation capacity from hydro/renewables as presented in Appendix A). In most other states and provinces, fossil fuels supply a significant portion of generation. Across the US, coal supplies about 40% of generation, with natural gas supplying just under 30%. (see US EPA, US Fuel Mix 2001-2013, http://www.epa.gov/cleanenergy/energy-and-you/)

[2] PUB website, Mandate - http://www.pub.nf.ca/mandate.htm

[3] Electrical Power Control Act, 1994, section 3, http://www.assembly.nl.ca/legislation/sr/statutes/e05-1.htm#3_

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would result in power being delivered to consumers in the province at the lowest possible cost consistent with reliable service".

Navigant carried out a jurisdictional review of all Canadian provinces and territories and six US states, as well as a high level review of international experience with NM. The review focused on questions relating to:

- Drivers for NM
- Program design/framework
- Regulatory treatment
- Customer and program costs/benefits
- NM experience

Based on this review Navigant identified some standard industry practices and "best practices" for NM policies; where "best practice" was interpreted as policies appropriate for NL's legislative and regulatory regime and generation mix and alignment aligns with the policy direction indicated in the Government's 2007 Energy Plan: *Focusing Our Energy*.

Navigant recommends that NL develop a NM policy which addresses the following key issues.

- Eligibility criteria, including:
    - Types of generation or energy sources permitted,
    - Customer class,
    - Limits on system capacity, and,
    - Limitations relative to customer load.
- Connection requirements, including the need for a technical review, standards to be applied for generator connections, safety inspections, etc.
- Meter aggregation rules.
- Allocation of costs for technical reviews, incremental meter costs, distribution system upgrades required, billing and administrative costs, etc.
- Rates applicable to net consumption and excess generation
- Settlement process to be used for excess generation supplied to the utility system.
- Subscription limits[4] which place an overall limit on the amount of generation capacity which can be installed under the program as a whole.
- Treatment of any credits that may be associated with the generation (Renewable Energy Credits, carbon credits, etc.).

Given the policy directions indicated in *Focusing Our Energy*, Navigant recommends that the following policy elements should be considered in developing a NM policy for the Province.

[4] Subscription limits are referred to in most US programs as "Aggregate Capacity Limits".

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1. **Eligibility Criteria**: It is recommend that NM be made available for:
   - Small-scale renewable generation systems.
   - Customer classes which cover "homeowners and small business operators"[5] and for customer systems sizes consistent with the emphasis on small scale. We note that it may be appropriate to interpret this limitation differently for connections in Island system and isolated and coastal communities served by diesel systems based on differing system capabilities. For example, it may be appropriate to apply a system capacity limit of 50kW or 100kW in the Island System but a lower limit in smaller diesel systems.
   - Generation installations should be limited relative to the customer's load. This could be done by adopting the IREC[6] model rule that "*individual system capacity does not exceed the customer's service entrance capacity*", or by limiting the connected generation relative to the customer's load (i.e. Arizona limits generation to 125% of the customer's load). This type of limit would be consistent with the Government's stated policy goal of allowing residential and small business "*to install small generation units to produce power for themselves and feed some back in the system when they produce more than they need*"[7]. Limiting system capacity to the customer's load will also help limit issues relating to settlement for excess generation from NM systems.

2. **Connection Requirements**: It is recommended that:
   - Transparent requirements for connecting NM installations be established by the utilities and made publicly available for potential NM customers prior to implementing the policy.
   - Rules for approving NM connection should include a requirement for a technical review by the utility.

   We anticipate that the utilities will be able to adopt existing standards for customer and generator connections for this purpose, but it is recommended that consideration be given to means of streamlining these processes in order to provide a timely response and minimize administrative costs. Navigant suggests that NL consult with BC Hydro regarding their experience in streamlining their process.

3. **Meter Aggregation**: Navigant suggests that meter aggregation not be permitted under the policy.

   Note - There may be reason to allow some limited exceptions, such as multiple meters on the same property to be consolidated, however, excluding aggregation is consistent with most other jurisdictions and will help limit administrative issues, including settlement issues that may arise if aggregation is permitted.

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[5] Newfoundland and Labrador, *Focusing Our Energy* – Energy Plan, page 40.
[6] Interstate Renewable Energy Council, Net Metering Model Rules, 2009 Edition, pg. 2
[7] *Focusing Our Energy*, page 24.

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4. **Cost allocation**:

- The NM policy should clearly articulate responsibility for different costs associated with NM installations. While there is no standard industry practice, most jurisdictions require the customer to pay for additional meter costs and permits required while the utility pays for additional billing and administrative costs.

- We concur with the IREC recommendation that under a well-designed program for small (i.e. <50 or <100 kW) NM installations[8] it is expected that the costs of technical reviews of connection requests, incremental meter reading and billing costs, and administrative costs should be negligible over the rate base; however, consultation with the utilities is recommended.

  It should also be noted that some customer connection requests could require distribution system upgrades to accommodate. In these instances, we recommend that the utility be provided discretion as to whether a connection request can be accommodated and whether the costs of any required upgrades should be recovered from the NM customer.

5. **Settlement**:

- Navigant suggests that NL consult with the utilities as to the most efficient and equitable settlement solution.

- We recommend that the customer's net consumption be billed using the tariffs which would normally apply to a customer of the same size, type and location and that the customer be compensated for excess power at the same rate, unless the Government chooses to introduce a different rate for power produced from renewable sources.

With regards to settlement for excess generation produced from NM systems and fed into the utility system, we suggest two options be considered:

i. Credit "net excess generation at the end of a billing period" to the customer's next bill as a kWh credit (as recommended by IREC) on an on-going basis. This offers a simple solution given that NM systems are limited to be approximately the same size as the customer's load. It is recommended that if this approach is taken that these accounts be monitored annually to identify any accounts which are developing a significant credit over a 12-month period.

ii. Separately track net excess generation for NM installations and settle annually with a cash payment or bill credit, calculated at the rates normally applicable to the account. It is anticipated that this would be an off-line process separate from the utility's normal billing process and would therefore add some administrative costs.

[8] While the NL Energy Plan does not define "small" generation we expect that NM installations will be limited to a threshold of 50 or 100kW. Navigant has also recommended that eligibility rules limit generation capacity to approximate customer loads.

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As discussed in the "Considerations for a Provincial Net Metering Policy" section of the report, if avoided costs differ substantially from rates, settling for excess generation using the rates applicable to the customer may result in some degree of cross-subsidization. This cross-subsidization could flow in either direction depending on the relationship between rates and avoided costs. In this case, the use of avoided cost in the settlement process would reduce the risk of cross-subsidization.
6. **Subscription Limits**: • Navigant does not expect that an overall subscription limit for the program as a whole is required for NL given the policy objective and Provincial context. We recommend, however, that the utilities be encouraged to monitor the response to the policy and provided the opportunity to recommend an overall capacity limit should the need develop.
7. **Associated Credits**: • While there is not currently a significant market for Renewable Energy Credits or Carbon Credits that could be associated with small-scale renewable generation, we recommend that the policy be clear in stating that the customer would retain these credits.
8. **Legislative Framework**: As discussed, NM policies have been introduced in different jurisdictions by legislation, through government direction to regulators, and voluntarily by utilities. We suggest that the most appropriate path for NL would be to have a NM policy developed under the auspices of the PUB, either directly as part of a PUB process or by directing the utilities to develop a policy for PUB approval. This approach would be consistent with the Government's statement that it will ensure that "regulatory support is in place for customers who wish to develop these alternatives". A policy developed by the PUB would also be subject to its normal considerations that rates be "just and reasonable" and that the service provided be "safe and reliable". We understand, however, that the PUB may be restricted by its mandate if it deems that there is some risk of cross-subsidization. We therefore recommend that Natural Resources discuss the proposed approach to a NM Policy with the PUB to determine if it would be acceptable. If it is determined that concerns about potential cross subsidization would preclude the PUB from implementing a NM policy, then legislation should be considered to authorize the PUB to implement NM.

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1 Introduction

The following section sets out the context for the NM review. The balance of the section first discusses the objectives of the study, then describes the industry and regulatory structure of Newfoundland and Labrador's electric system and finally provides an introduction to NM.

1.1 Context for Review

Context for Review

The Newfoundland and Labrador DNR retained Navigant to carry out a review of industry practices with respect to NM policies and practices in Canada and other leading jurisdictions. The review is part of a commitment in the Provincial Government's 2007 Energy Plan: *Focusing Our Energy* to develop and implement a NM policy that will provide regulatory support for small-scale renewable energy sources. Navigant worked with a Steering Committee comprised of members of the DNR and representatives of NLH and NP who provided guidance for the review. The findings and considerations for a NM policy presented in the report are Navigant's but were reviewed with the Steering Committee.

In its 2007 Energy Plan the Newfoundland and Labrador Government committed that it "*will ensure that regulatory support is in place for customers who wish to develop these alternatives themselves on a small scale, through a net metering policy*". We have interpreted this focus on small scale, renewable sources and providing customers with access to connect to the utility grid as key in identifying appropriate elements for a NM policy for the Province.

Overview of the NL Electricity System

The NL electricity system has nearly 7,500 megawatts (MW) of generating capacity and a transmission-distribution system serving over 290,000 customers on the Island system, the Labrador system or one of the province's 22 isolated diesel systems in coastal communities. The Island grid differs from many other North American systems in that it is physically isolated from Labrador and the North American system. The Labrador system is connected to the Hydro-Quebec system via three high voltage transmission lines used to export the majority of the 5,428 MW of power from the Upper Churchill Falls generating plant.

With the development of the Muskrat Falls project, the Island system will gain two interconnection points:

1. Interconnection with Labrador by the Labrador-Island Link transmission line and
2. Interconnection with the Nova Scotia (NS) system and the North American system by the Maritime Link transmission line.

Electricity supply and distribution service in the province is provided by two utilities, NLH and NP.

- **NLH**[9] is a crown-owned electric utility which owns and operates facilities for the generation, transmission and distribution of electricity to utility, industrial and retail customers in the Province of Newfoundland and Labrador. It is primarily a wholesale and transmission utility, and Newfoundland Power is its largest customer. NLH directly serves over 38,000 residential customers in 220 communities across the province. This includes operating 21[10] diesel systems to provide service to 4,400 customers in isolated and coastal communities throughout Newfoundland and Labrador. NLH also sells power to five regulated industrial customers on the Island.
- **NP**, an investor-owned company, is primarily a distribution utility that sells electricity to approximately 86%, or over 255,000, of the retail customers on the Island interconnected system. The Company generates approximately seven percent of its electricity needs and purchases the remainder from NLH and is currently required to purchase power only from NLH.

While the vast majority of customers in the province are residential (approximately 90%), these customers only purchase slightly more than half (approximately 55%) of the electricity sold by utilities in the province. The remaining electricity (approximately 45%), is purchased by 10% of customers, which include general service and large industrials.

NLH and NP are regulated by the PUB-NL. The PUB-NL's jurisdiction over electric public utilities in the province is defined primarily by the following legislation:

a) The *Electrical Power Control Act, 1994* (EPCA) sets out the power policy of the province and gives authority to the PUB-NL to implement the policy. The EPCA declares that rates charged to electrical customers should be reasonable and not unjustly discriminatory, allow sufficient revenue for the producer or retailer of the power to earn a just and reasonable return while maintaining a sound credit rating in world financial markets and promote the efficient production, transmission and distribution of power at lowest cost consistent with reliable service. The Lieutenant-Governor in Council retains the right to direct the PUB-NL on rates policy and procedures, issue exemptions for a public utility under the EPCA (same authority under the *Public Utilities Act (PUA)*) as well as refer matters to the PUB-NL relating to rates and other issues. As well, the EPCA gives the PUB-NL authority to ensure adequate planning by

[9] NLH is a subsidiary of Nalcor.

[10] NLHalso operates the Natuashish generation and distribution system on behalf of the Mushuau Innu First Nation.

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the utilities occurs for future production, transmission and distribution of power in the province as well as provides the PUB-NL the authority to allocate/re-allocate power in the event of a shortage. The Lieutenant-Governor in Council can also appoint an emergency controller during a state of emergency to make decisions and issue directions and orders related to the oversight and operation of the provincial power system.

b) The PUA defines the general powers of the PUB-NL regarding its oversight of provincial public utilities including: approval of electricity rates and costs to be recovered in rates, approval of capital budgets, holding hearings and conducting investigations, hearing applications and complaints, issuing orders, as well as ensuring adequate provision of electricity service and compliance under the PUA. The PUA defines a public utility in the province as an entity that owns, operates, manages or controls equipment or facilities related to the providing of electric power or energy, water, heat or sewage to or for the public or a corporation for compensation.

Other electricity sector related legislation in NL includes the *Hydro Corporation Act 2007*, the *Energy Corporation Act*, the *Energy Corporation of Newfoundland and Labrador Water Rights Act* and the Churchill *Falls (Labrador) Corporation Limited (Lease) Act, 1961*.

The PUB-NL's web site indicates that its legislated mandate is to "*ensure that the rates charged are just and reasonable*"[11]. The power policy for the Province, as stated in the *EPCA*[12] includes requirements to ensure that electrical rates "*should be reasonable and not unjustly discriminatory*" and that the power system should be operated and managed in a manner "*that would result in power being delivered to consumers in the province at the lowest possible cost consistent with reliable service*".

In 2013 the Island electricity system had a total generating capacity of 1,946 MW. Most of this capacity (83%) is operated by NLH, with the remainder operated by NP, Corner Brook Pulp & Paper, and non-utility generators (NUGs). NUGs include 54 MW of wind, which is sold to NLH.

As shown in Figure 1, the majority of the electricity on the Island Interconnected system is generated by hydroelectric generation. As the proposed Muskrat Falls project comes on line, the proportion of generation derived from renewable sources on the Island is expected to

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[11] PUB website, Mandate - http://www.pub.nf.ca/mandate.htm

[12] ELECTRICAL POWER CONTROL ACT, 1994, section 3, http://www.assembly.nl.ca/legislation/sr/statutes/e05-1.htm#3_

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increase to approximately 98%. On the Labrador Interconnected System, almost 100% of the electricity is generated by hydraulic sources.

Figure 1: Island Interconnected Electricity Supply - Generation by Source

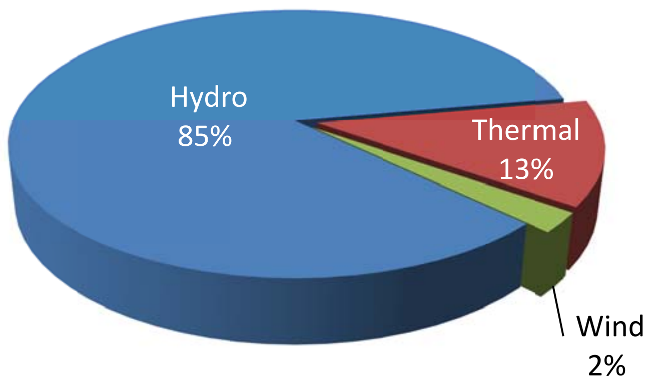

Figure 2 illustrates the Newfoundland and Labrador transmission system.

Figure 2: Newfoundland and Labrador Transmission

Source: NL Hydro System Planning Department 2014.

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In 2013, the Island electricity system had a peak demand of 1,651 MW and an annual energy requirement of 7,996 GWh. Electricity demand is typically highest during the evenings in colder winter months. NLH defines the peak period as the morning period from 7:00 a.m. to noon and the evening period from 4:00 to 8:00 p.m. during the four coldest months of December to March.

1.2 Overview of Net Metering

NM policies allow customers with small generating facilities to generate power from renewable sources for their own use, as well as feed power into the distribution system during periods when their generation provides power in excess of their needs and to draw power from the grid at times when their generation does not fully meet their needs. A common definition of NM refers to it as a "*billing arrangement by which customers realize savings from their systems, where 1 kWh generated by the customer has the same value as 1 kWh consumed by the customer*"[13].

NM policies have been implemented by the majority of Canadian provinces and US States as well as in numerous other jurisdictions. The rules under which NM can occur and how customers are compensated for the power delivered into the grid vary but there are a number of common elements in NM policies. *Focusing Our Energy* notes that some homeowners and small business operators in NL would like to be able to install small generation facilities and have the ability to feed some power excess to their needs back into the system. A NM policy would enable these customers to obtain value for this excess power and provide access to the grid for periods when their generation isn't sufficient to meet their needs.

NM policies are often introduced as part of a broader policy aimed at encouraging the greater use of distributed generation from renewable resources; particularly in jurisdictions which, unlike NL, are very dependent on fossil fuels. In many jurisdictions, NM policies are combined with a Feed In Tariff (FIT) which pays generators a higher rate for electricity generated from renewable sources such as wind or solar photovoltaics (PV). In some jurisdictions, relatively high electricity rates and falling PV system costs, have led to rapid growth in distributed generation. This has led to considerable controversy in some jurisdictions and a review of both NM and FIT policies.

Navigant notes that the focus of this report is on NM policies. In discussing jurisdictions which have introduced both a NM and a FIT policy, the report will distinguish the effects of rates provided through programs such as a FIT policy from the effects of the NM policy.

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[13] Interstate Renewable Energy Council (IREC*), Freeing the Grid 2013: Best Practices in State Net Metering Policies and Interconnection Procedures*, November 2013, Page 5.

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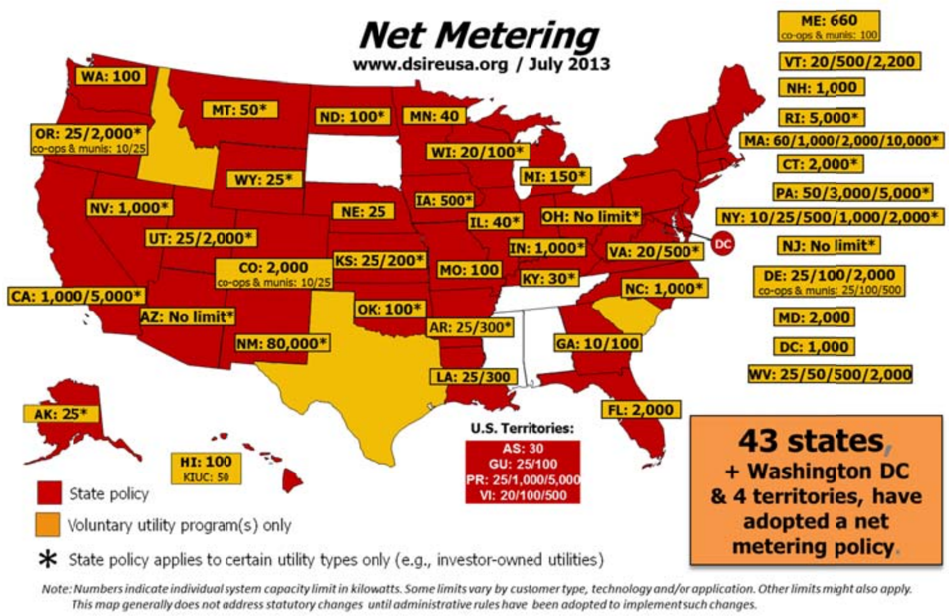
Across Canada, NM is allowed in almost every province and territory in Canada, though there are a number of restrictions on the type of customer and size of systems which may participate.

In the US, the *Energy Policy Act of 2005* required all public electric utilities to offer NM on request to their customers. As of 2013, 43 states, Washington, DC and four US territories have adopted a NM policy (as shown in Figure 3 below). Utilities in three other states (Texas, Idaho and South Carolina) have voluntary NM programs.

Figure 3: NM Policies in U.S.



NM programs have been criticized in some jurisdictions for their potential to shift costs from NM customers to non-NM customers[14]. This shifting of costs can occur when the lost revenues from reduced kWh sales exceed the utility's avoided costs. This is most likely to occur in situations where distribution and transmission costs are recovered through rates which are based primarily on the volume of energy consumed[15]. Estimating the rate impact of NM involves an assessment of a number of costs and benefits associated with the policy.

The impacts of a NM policy can differ between jurisdictions depending on the structure of the electricity market and will be affected by the structure of the utilities, electricity rates, and the regulatory framework (Figure 3).

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[14] E.g., Arizona Energy Future. "Many Influential Voices Agree: Cost Shift From Net Metering Needs To Be Fixed." http://www.azenergyfuture.com/blog/october-2013/many-influential-voices-agree-cost-shift-from-net/. October 13, 2013.

[15] In contrast, some jurisdictions have separated or "unbundled" costs so that customers pay for a greater proportion of fixed costs related to distribution and transmission services through a fixed charge per bill.

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For example, if NM customers are able to avoid distribution and transmission costs while still enjoying the benefits of accessing the electric system to supplement their generation then it is possible that some cross-subsidization may occur. By contrast, in jurisdictions where rates have been "unbundled" and costs allocated to specific distribution, transmission and commodity charges, the potential for cross-subsidization is reduced.[16]

[16] For example, in Alberta the NM policy provides customers a credit for excess electricity sent to the grid based on the retail energy rate portion of their rate which does not include the volumetric charge associated with transmission and distribution costs.

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2 Lessons from Other Jurisdictions

The following section describes the process by which jurisdictions were selected for inclusion in the review of NM industry practices and summarizes the key lessons learned from that review. As will be discussed, NM policies were reviewed in all Canadian provinces and territories as well as a select list of US states. This review was supplemented by a high level review of international experience outside of the US and Canada.

2.1 *Jurisdictional Review Process*

In order to provide an understanding of industry practice with respect to NM, Navigant conducted a policy and regulatory scan of NM policies currently in place or under consideration in Canada's provinces and territories as well as for jurisdictions in the US and outside of North America. Navigant initially proposed to include up to four US states and up to three other jurisdictions outside of North America in the jurisdictional review.

After discussion with the Steering Committee, Navigant recommended that the review include a few leading jurisdictions which have experienced high participation and uptake of NM and that the balance be selected from among jurisdictions which have implemented NM in systems and with policy frameworks which are similar to those in NL. Jurisdictions were screened for the following characteristics:

- High levels of renewable or non-fossil generation, similar to NL,
- Vertically integrated utilities with bundled rates,
- No retail access, and,
- A policy emphasis on limiting cross-subsidization between NM customers and non-NM customers.
- Regulatory structure comparable to NL.

While few jurisdictions were expected to meet all of these criteria, Navigant identified jurisdictions which met as many of these criteria as possible.

After an initial screening and review of a number of jurisdictions outside of North America it was determined that there were few jurisdictions that were a reasonable match to the criteria established for NL. In consultation with the Steering Committee it was determined that expanding the number of US states included in the review and providing a high level review of international experience outside of North America would add greater value to the study.

A number of research questions regarding NM were identified in the RFP.

The jurisdictional review undertook to answer as many of these questions as possible, and the following sections summarize Navigant's findings regarding these issues.

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Table 1: Research Questions

Research Question	Specific Information per RFP
Drivers for NM	• Driving force behind NM policy *(e.g. legislated by government; voluntary by utilities).*
Program Design/ Framework	• Legislative considerations • Eligibility requirements • Meter aggregation (*e.g. single meter, premise aggregation, distribution zone aggregation*) • Customer classes and capacity limits (*e.g. 100 kW versus 1,000 kW; NM versus feed in tariffs (FITs) versus non-utility generators (NUGs); types of meters for each customer class*) • Determination, monitoring and enforcement of the match between a customer's generation capacity limit and their generation needs • Subscription limits (*e.g. percentage of provincial load*) • Implementation and administrative issues
Regulatory Treatment	• Cross-subsidization issues (*e.g. whether transmission and distribution costs from NM customers are transferred to non-NM customers*) • Regulators' analyses and rulings on NM in order to obtain regulators' views of the review, design, implementation and evaluation of NM programs
Customer & Program Costs/Benefits	• NM rate structures • Monthly bill determination • Compensation rate for net metered power (*e.g. retail rate, avoided cost*) • Approach and structure of any customer payout anniversary date (*e.g. account credit, Cash payout , monthly/quarterly/yearly*) • Responsibility for associated NM costs (*e.g. engineering studies, distribution equipment upgrades, metering upgrades, related billing costs*)
NM Experience	• Customer participation / uptake rates.

US States Selected for Review

Following a review of potential jurisdictions and discussion with the Steering Committee, it was agreed to include the following US states in the review.

- **Arizona** (AZ) has one of the most active programs in the U.S. and has experienced a number of issues as a result of very strong program enrolment. Arizona introduced retail competition in the late 1990's but suspended it after the California energy crisis. In a 2012 white paper on *Net Metering Bill Impacts and Distributed Energy Subsidies*, prepared for Arizona Public Service (APS), Navigant offered the following description of the NM policy.

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> *"Arizona net metering rules were implemented in May 2009. Net metering is available to customers that generate electricity on-site using solar, wind, hydroelectric, geothermal, biomass, biogas, combined heat and power (CHP), or fuel cell technologies. Customers that participate in net metering receive bill credits in each billing period for PV generated electricity that exceeds the amount they consume during the billing period. Any bill credits that exceed a customer's consumption in that billing period are either netted against future consumption within that same month or "banked" at the end of the month and used to offset charges in future months for actual customer consumption of APS-provided electricity. As a result, PV customers' credits are conceptually equivalent to selling excess generation back to the grid at the retail rate that APS would have charged them for that electricity"*[17].

The Arizona Corporation Commission (ACC) recently reviewed the States NM policy in a response to a request from the main utility in the state (APS). The review, which examined the issue of cross subsidization, is discussed in greater detail in section 2.2.3.

- **Idaho** (ID) is one of three US states with a voluntary NM program initiated by state regulator. Unlike other states which have a state-wide program, each of Idaho's three investor-owned utilities (IOUs) have developed a NM program and tariffs for approval by the net-metering tariff approved by the Idaho Public Utilities Commission (PUC). The three utilities' programs share the same capacity limits (100kW) and -until recently- also shared the same aggregate capacity limit (0.1% of the utility's peak demand within Idaho). In 2013, as Idaho Power Company (IPC), Idaho's largest IOU, approached -and later surpassed- its 0.1% limit, the PUC decided to waive its capacity limit[18]. Also in 2013, IPC argued that their NM policy resulted in cross-subsidization by non-NM customers; the PUC reviewed the utility's arguments, found that there was no significant cross-subsidization, and maintained the NM policy[19].
- **Oregon** (OR) is one of the few other US states with a predominantly hydraulic based generation system, with 82% of its power coming from renewable sources. The State allows retail competition and first enacted NM legislation in 1999. Oregon has established separate NM programs for the state's IOUs and 36 public utilities, each of the which have set up distinct NM practices.
- **South Carolina**'s (SC) electric system is dominated by nuclear generation which supplies almost 60% of the state's net electricity generation. In April of this year, the SC legislature passed a bill creating a voluntary "*Distributed Energy Resource Program*". The bill mandated the state regulator to develop new NM rules and offered a number of guidelines for eligible

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[17] NM Bill Impacts and Distributed Energy Subsidies, prepared for APS by Navigant Consulting, Inc., December 11, 2012, page 4.
[18] Idaho Public Utilities Commission, Final Order – Case No. IPC-E-12-27. July 3, 2013.
[19] Freeing the Grid 2013: Best Practices in Net Metering Policies and Interconnection Procedures, Interstate Renewable Energy Council (IREC), November 2013, page 15.

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system types and sized, cost recovery and rules for structuring rates. Cooperatives in the state are required to examine their NM rules but are not required to implement a program[20].

- **Vermont's** (VT) electricity system differs from NL in that it has a limited amount of hydro-electric resources (17% of generation) but is similar in that it includes very little fossil generation; relying largely on nuclear (76% of generation). VT does not allow retail choice but has had a NM policy in place since 1998. The policy sets different capacity limits for residential, commercial and government or military sectors, and sets a subscription limit equal to 15% of a utility's peak demand.
- **Washington State** (WA) has a largely (77%) hydraulic based generation system similar to the NL generation mix. The state does not allow retail competition. It implemented a NM policy in 1998 which applies to systems up to 100kW with an overall subscription level set at 0.5% of a utilities peak demand.

Appendix A includes a summary of the information collected regarding each of the Canadian Provinces and Territories and the six US States.

International Jurisdictions Outside of North America

NM has been introduced in jurisdictions ranging from the Philippines[21] and Australia, to Europe and the United States. Navigant reviewed NM policies in a number of European jurisdictions, including the UK, as well as state-level programs in Australia.

In the EU, the development of NM was delayed due to concerns over how NM would be treated under EU Value Added Tax (VAT) laws. Norway, for example, which has a generation mix similar to NL considered a NM policy but concluded along with countries such as Sweden and Denmark that NM would be in conflict with VAT laws and therefore pursued other avenues to encourage renewable investments[22]. In 2012, the Swedish government announced a public inquiry into the implementation of NM, which was described as a means of achieving net billing, such that only the net metered electricity would be measured using a single meter. The public inquiry commission ruled that Swedish VAT laws require electricity to be taxed for the total amount supplied, whether exported or imported from the NM generation system to the utility. The public inquiry commission ruled against the proposed definition of net

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[20] US Department of Energy, Database of State Incentives for Renewables & Efficiency (DSIRE), Net Metering State Summaries (South Carolina), http://www.dsireusa.org/incentives/allsummaries.cfm?SearchType=Net&&re=1&ee=0

[21] Republic of the Philippines, Republic Act No. 9513: An Act Promoting the Development, Utilization and Commercialization of Renewable Energy Resources and for Other Purposes. July 2008.

[22] Legal Sources on Renewable Energy, http://www.res-legal.eu/search-by-country/netherlands/

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metering, and judged that exported and imported electricity should continue to be measured separately[23].

European jurisdictions also differentiate between "Self Consumption" and "Net Metering" policies. "Self-Consumption" policies allow "*any kind of electricity consumer to connect a photovoltaic system, with a capacity corresponding to his/her consumption, to his/her own system or to the grid, for his/her own or for on-site consumption, while receiving value for the non-consumed electricity which is fed into to the grid*"[24]. NM, by contrast, is viewed as a billing process by which production and consumption are compensated over a longer period, such as over a year.

Most EU countries which have offered NM have combined the policy with a Feed-In Tariff (FIT) program designed to encourage the development of renewable power[25]. A number of these countries have cancelled those FIT initiatives in recent years following the financial crisis. Others, such as France and Portugal have discussed NM but have not yet implemented a policy.

Germany has had one of the most active programs in the EU, offering an attractive FIT since 2000 to encourage the development of renewable energy technologies. Germany has set a goal of supplying 40-45% of its electricity consumption from renewable sources by 2025 and has reported that renewables provided 28.5% of gross electricity production in the first half of 2014[26]. Germany has made a number of adjustments to its FIT program in recent years and have made frequent adjustments to the FIT since 2012 in response to changing electricity and solar PV prices.

The Netherlands represents one of the few EU jurisdictions which has had a long-standing NM policy. Unlike NL, the Netherlands depend on fossil fuels for over 80% of their electricity and import 5-10% from neighbouring countries[27]. The Dutch policy, in place since 2009, focusses on providing non-discriminatory access to the system to small producers of renewable power.

In Australia, as in Europe, the driving force behind NM policies has been the encouragement of renewable generation through FIT programs. Australia is also heavily dependent on fossil

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[23] Energy Markets Inspectorate, Adapting Electricity Networks to a Sustainable Energy System, 2011, https://www.smartgrid.gov/sites/default/files/doc/files/Adapting_Electricity_Networks_to_Sustainable_Energy_System_201108.pdf

[24] EPIA, Self Consumption of PV Electricity: Position Paper, July 2013, page 2.

[25] Most of these EU countries have historically been largely dependent on fossil fuels for power generation.

[26] Preliminary figures from the Federal Association of Energy and Water Industry, as reported in the "German Energy Blog: Energy in Germany – Legal Issues, Facts and Opinions", July 29, 2014. http://www.germanenergyblog.de/?p=16368

[27] About 60% of Netherland's generation is from natural gas. See: World Bank, World Development Indicators: Electricity Production, sources and access, Table 3.7. http://wdi.worldbank.org/table/3.7

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fuels, obtaining almost 70% of its electricity from coal and about 90% from fossil fuels[28]. PV systems are reported to have reached grid parity in some parts of Australia and PV electricity production reached 2.3% of total electricity consumption in 2013. Some states in Australia have experienced a significant increase in the installation of PV systems in recent years and are also reviewing issues of cross-subsidization.

Navigant conducted a high level review of experience in these jurisdictions and has incorporated some of the lessons learned into considerations for NL, however, we note that the policy strategy underlying the NM policies in most of these jurisdictions does not align with the policy direction described for NL. Many of the jurisdictions reviewed are dependent on fossil generation for a significant portion, or the majority, of their electricity production and several have pursued a policy to encourage the development of renewable sources as part of an economic strategy. NL, in contrast, currently generates the vast majority of its electricity supply from renewable generation and anticipates this will increase to 98% renewable generation once Muskrat Falls comes in-service. Therefore, NL is not considering a provincial NM policy in order to avoid fossil fuel generation, but rather to provide greater flexibility to residential and small business customers wishing to install renewable generation systems.

2.2 *Lessons from Other Jurisdictions*

The following sub-sections describe common industry practices with respect to NM policies and elements of those policies which were found to vary between jurisdictions. The section is structured to respond to the research questions identified in the NL RFP. Appendix A includes a summary of the information collected regarding each of the Canadian provinces and territories and the six US states. Appendix B provides a summary of some key information for each jurisdiction reviewed.

2.2.1 Policy Drivers

While the rationale for introducing an NM policy is not always clearly stated, most of the jurisdictions reviewed have introduced NM policies in order to encourage and support the development of renewable or clean distributed generation. In some jurisdictions, such as Ontario (ON) this policy objective has been further supported through the use of a Feed In Tariff which provides higher rates for electricity generated from renewable sources. Four Canadian provinces (British Columbia [BC], New Brunswick [NB], Prince Edward Island [PEI], and Saskatchewan [SK]) developed NM as part of a policy goal to support the increased adoption of renewable resources. These provinces have quite different existing generation

[28] World Bank, World Development Indicators: Electricity Production, sources and access, Table 3.7. http://wdi.worldbank.org/table/3.7

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mixes, ranging from BC which is largely hydraulic, to SK which derives 80% of its power from coal to NB where the generation system is dominated by nuclear output.

The driving force behind the development of NM policies has also varied. In Canada, for example:

- Four Canadian jurisdictions (Alberta [AB], ON, PEI and Yukon [YK]) legislated the introduction of NM which was then implemented by the corresponding electricity regulator.
- In two provinces (BC and Quebec [QC]) NM was developed by the electricity regulator in response to a government order. NB and SK, followed a similar path in that the government ordered the development of a NM program which was then developed by the crown utility.
- In two other jurisdictions (NS and the Northwest Territories [NWT]), utilities implemented a variation of an NM program prior to any regulatory approval or government action. Nova Scotia Power Inc. (NSPI) offered NM since 1989, and in NWT, Northland Utilities (an IOU) and NWT Power, both offered a net billing pilot program.

While Manitoba (MB) offers its Customer Owned Generation program, the driving force for the program is unknown. Nunavut is the only jurisdiction that does not offer a NM program. Qullig Energy, the sole electricity provider, noted in its *2012 / 2013 Annual Report* that a NM policy was being developed.

As mentioned in section 1, in the US, the *Energy Policy Act of 2005* required all public electric utilities to offer NM on request to their customers. Several of the states reviewed for this study had introduced legislation requiring NM prior to that Act. In two of the US jurisdictions reviewed (AZ, and SC), the NM policy was developed by the electricity regulator. In Idaho utilities developed the policy which was approved by the regulator. In the other jurisdictions (WA, OR and VT), the NM policy was specified in legislation. An explicit policy strategy of increased adoption of renewable resources was the driving force behind the policy in the majority of US states reviewed (AZ, WA, OR, SC and VT).

2.2.2 Program Frameworks and Designs

Legislative considerations

The market structure in place in a jurisdiction has obvious implications for how NM policies are structured. Jurisdictions which have open access to the transmission and distribution systems, retail competition or where the industry has been restructured to separate generation, transmission and distribution into separate entities recognize these elements in their NM policies. In AB and ON, for example, the electricity market structure required that NM programs be implemented by the electricity wire service provider (WSP), or the local distribution company (LDC).

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As mentioned, a number of jurisdictions have implemented NM as part of a broader strategy to encourage the development of renewable energy sources. These jurisdictions are more likely to require the regulator to take investments in renewable energy programs into consideration when setting rates and to encourage higher payments for power produced by NM installations. In other jurisdictions, where the policy is not focused on supporting the development of additional renewable sources (as in MB, for example), cost-of-service pricing is more likely to be used for NM customers.

In the US jurisdictions reviewed, the electricity market structure, comprised of public power and investor-owned utilities has affected the implementation of NM projects. In four jurisdictions (AZ, WA, ID and SC), the regulator only has jurisdiction over IOUs; and not public utilities (municipal and co-ops). In OR, where the PUC only regulates the IOUs, legislative rulings required all utilities -including publicly owned utilities- to offer a NM program. In VT, legislation mandated all electric utilities to offer a NM program. In SC, which is served by several large utilities, the regulator required each utility to propose and implement a NM policy. Five of the jurisdictions (AZ, SC, WA, OR and VT), allow third parties to finance, build, and own a NM system for customers. Through third party ownership, large capital costs are lifted off of residential customers, which eases the uptake of NM participation. In AZ, as of Q2 2012, 80% of residential installations were third party owned[29].

Eligibility requirements

All NM policies reviewed included eligibility requirements. As expected, the policies generally specified a number of eligibility criteria, such as the size of generators eligible under the policy; however, the specific requirements varied between jurisdictions, reflecting differing policy objectives and system considerations. Some common eligibility criteria included:

- Type of generation (i.e. renewable or other)
- Maximum generating capacity
- Capacity relative to customer load
- Customer class or type

In addition a number of jurisdictions placed overall subscription limits on the policy. These typically relate the connected load participating in the program to the total capacity of the utility system.

[29] SC Energy Advisory Council, Distributed Energy Resources Report, January 2014, pg. E-2

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The actual limits associated with these criteria differ between jurisdictions.

a) Type of generation

In most jurisdictions, NM eligibility is restricted to renewable generation. In Canada all of the provincial policies except MB limit the availability of NM system to renewable and alternative energy generation[30]; though the actual definition and inclusion of technologies varies. The US states reviewed all have similar requirements that NM systems be renewable or clean resources. Some States have gone further and permit the use Combined Heat and Power (CHP), fuel cell technology, and geothermal resources in the program.

b) Meter aggregation

Some NM policies allow generators to "aggregate" or combine generation from different locations owned by the same customer, however this practice is uncommon or closely limited. Five Canadian jurisdictions (ON, QC, PEI, SK and YK) do not allow aggregation. Four jurisdictions do allow for aggregation (AB, BC, NB and NS); most on a limited basis. Of the four allowing some form of aggregation, AB and BC allow meter aggregation for NM generation systems on adjacent properties. In NB, exceptions are allowed for farm customers, and in NS, aggregation is allowed for accounts located within the same distribution zone[31]. The policy in NWT does not address aggregation, and the policy on aggregation in MB is not known.

Of the six US jurisdictions reviewed, two (AZ and SC) do not allow meter aggregation, while the remaining four jurisdictions (WA, ID, OR and VT) allow meter aggregation under some conditions. WA and VT allow meter aggregation if the meters are located within the utility's service territory, and do not require meters to be under the same customers. ID and OR allow aggregation under certain restrictions. In both cases the policy limits aggregation to meters which serve the same customer, are on contiguous properties and are served by the same feeder.

c) Customer classes and capacity limits

The majority of NM policies are designed for residential and small business customers and this is reflected in the class and capacity limits placed on eligibility. As with other policy elements the limits on eligibility tend to reflect the policy objective driving the NM policy.

In Canada, for example, nine jurisdictions had a 100kW (or lower) capacity limit for residential or single phase customers, and of these nine, four have a capacity limit less than or equal to

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30 Alberta's program allows "other source with GHG intensity less than 418kg/MWh" while Manitoba's Customer Owned Generation program also allows non-renewable alternative energy systems.

31 Defined as on being served by feeders which originate at the same transformer.

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50kW[32]. AB, permits a much higher capacity limit of 1MW under its policy, but limits the generation connection based on the size of the customer's electricity load.

Of the six US jurisdictions reviewed, three (ID, OR and SC) impose different capacity limits on residential systems (ranging from 20-25kW), and non-residential systems (100kW to 1MW). WA and VT impose residential limits of 100 and 500kW, respectively. AZ restricts generation capacity to 125% of the customer's load.

Table 2, below, provides a summary of the capacity limits for each province and territory in Canada, as well as the six states examined in the US. As the table shows, different jurisdictions have used different criteria (customer class, service type, etc.) in specifying capacity limits.

Table 2: Capacity Limits by Jurisdiction

Canada	Capacity Limits	U.S.	Capacity Limits
AB	1MW	AZ	125% of Customer Load
BC	50kW[33]	ID	25kW (residential/small commercial) 100kW (industrial)
MB	50kW (single phase) 1MW (triple phase)	OR	25kW (residential), 2MW (non-residential)
NB	100kW	SC	20kW (residential), 1MW (non-residential)
NS	100kW (residential/commercial) 1MW (large commercial/industrial)	VT	500kW (all customers) 20kW (micro-CHP) 2.2MW (military)
ON	500kW	WA	100kW
PEI	100kW		
QC	50kW		
SK	100kW		
YK	5kW (shared transformer) 25kW (single transformer)		
NWT	5kW		

To put these numbers in context, according to CMHC[34], a solar PV system installed in St. John's would be expected to produce about 933 kWh/kW of installed capacity. In contrast, a home using electric heat would be expected to require over 2,000 kWh/kW of heating capacity installed.

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32 Ontario is the exception; allowing customers to install systems up to 500kW.

33 Increase to 100kW was approved on July 2014

34 Canada Mortgage and Housing Corporation (CMHC), Photovoltaic Systems, Table 2, Yearly PV potential of major Canadian cities and major cities worldwide, http://www.cmhc-schl.gc.ca/en/co/grho/grho_009.cfm#table2 .

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The majority of the jurisdictions reviewed also have other programs in place (i.e. feed-in-tariff, standard offer programs (SOP), large renewables procurement, etc.) which either overlap with the capacity limits of the NM programs, or whose minimum capacity was a continuation of NM capacity limits. For example, if a NM program imposed a capacity limit of 50kW, a SOP program might have limits of 50kW to 1MW, such that all generation systems fall into a program. Further, all US jurisdictions offered customers a variety of programs; NM, net billing and/or buy-all sell-all.

d) Capacity limits relative to customer load

Considerable variation was found in the requirement to match generation to the customer's load. This requirement is less common in jurisdictions which introduced NM as a means of encouraging renewable generation.

In Canada, four jurisdictions (AB, NS, QC and YK) require the system's capacity to be sized to the customer's load (as described in Appendix A). In AB, retailer-customer disagreements relating to system sizing have been ruled on by the Alberta Utilities Commission (AUC). The AUC has used the rating of the customer's transformer to determine the maximum capacity of a customer's system. A customer's system that exceeds that capacity would be subject to extraordinary costs, which are recovered directly from the customer.

A more important limiting factor, with respect to sizing, is a decision of whether to use an average or maximum demand (kW), or energy needs (kWh) of a customer's profile to determine the maximum system size. In AB, the AUC has ruled that the annual energy needs of a customer must be equal or greater than the expected energy supply from the generation being connected. In QC, an estimate is provided which considers a customer's load at a 35% capacity factor with respect to annual electricity consumption.

In the US only one state was found to have this type of restriction (AZ) which limits the capacity of a NM connection to 125% of the customer's connected load.

e) Subscription limits (e.g. percentage of provincial or utility load)

The inclusion of subscription limits on NM program participation tends to reflect the policy focus in the jurisdiction. Of all of the jurisdictions reviewed, about half have imposed subscription limits to their NM program.

Where a subscription limit has been included in the policy, it is generally set to equal less than 2% of total system generation capacity, though 1% is the most common standard. In NS, for example, the subscription limit was set at 0.5% of NSPI's generation capacity, while in ON, the limit was set at 1% of provincial capacity[35]. Some US states, such as Nevada have set higher subscription limits (3% of the total peak capacity of all utilities in the state). Other States have stated their "Aggregate Capacity Limit" for NM installations as a percentage of customer demands. In Vermont, for example the aggregate capacity limit for NM is set as 15% of the utility's peak demand in the most recent calendar year.

In Canada, four of the jurisdictions reviewed had subscription limits. These include NS and ON as previously mention, NB has set a limit 0.5% of their historic peak, and the NWT which, like NL, has both a system supplied by hydraulic generation and a number of separate communities served by diesel systems, has set separate subscription limits for on-grid (hydraulic) and off-grid (diesel generation) communities. As determined by Northwest Territories Power Corporation (NTPC) system simulations, NM installations are limited to 20% of the capacity of the diesel systems in off-grid zones. The limit for on-grid (hydro) zones is determined annually based on an assessment of NM impacts on the grid. In its NWT Solar Energy Strategy 2012-2017 (Action #7), the NWT government committed to investigate effective ways to increase the limit on NM systems up to 75% of the system's load in off-grid zones[36]. As of March 31 2014, 202kW of NM solar PV generation had been installed in NWT, accounting for 1.6% of the average load.

Subscription limits were found to be more common in the US jurisdictions reviewed. Five states (ID, OR, SC, WA and VT) impose subscription limits under their programs. AZ is the only state reviewed that does not impose a subscription limit. The subscription limits are generally imposed by the state regulator and often differ between IOUs and public utilities:

- The Idaho Public Utilities Commission (IPUC) instituted a 0.1% peak demand soft limit on IOUs. When Idaho Power Company reached the specified limit, the IPUC waived the limit. Idaho's other two IOUs have not reached the limits specified for their utilities.
- In OR, a subscription limit was not applied to the IOU's but the public utilities have a 0.5% peak load limit.
- In SC, the Public Service Commission (PSC) has a set a limit equal to 2% of the average peak demand over the past 5 years for all utilities.
- In WA, a limit was set at 0.5% of the 1996 peak demand for the three IOUs.
- In VT, IOUs and public utilities' limits are set a 15% peak demand.

Implementation and administrative issues

Connecting generation to a utility's system raises a number of technical and safety issues and all of the jurisdictions reviewed have an administration system to screen and approve

[35] In ON, the limit was set in terms of MW and has not been adjusted since March 2006. As a result it has fallen to about 0.75% of total system capacity.

[36] Northwest Territories, Solar Energy Strategy 2012-2017

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installations. Most of the jurisdictions which have had a system in place for some time have worked to develop a simplified application process; typically for smaller and less complex generation systems.

In Canada, six of the jurisdictions (NB, PEI, QC, SK, YK and NWT) offer a single application process for all applications. Four jurisdictions (BC, MB, NS and ON) offer a simplified and expedited process for systems that fall below a given capacity. Three of these use a 10kW limit, and the other (BC) uses 27kW. SK is considering implementing a simplified application process for projects <20kW[37]. In BC, 90% of projects were expedited based on the simplified <27kW limit[38]. As a result of this process, in Fiscal Year 2013 BC Hydro reported that their total expenditure on technical review of designs was only $2,000. BC Hydro is considering setting up a new process for projects that use a standardized design.

The remaining jurisdiction, AB, has a simplified application process for systems that meet three basic criteria related to environmental impacts and adverse impacts on others.

Four of the US jurisdictions reviewed (AZ, ID, OR and SC) offer a single application process for all applications. Only WA and VT offer two application processes, a simple process (for systems < 25kW and 15kW, respectively) and a complex process for all other systems.

Administration of a NM policy also includes on-going processes for billing customers and settlement systems if customers are compensated for any excess generation fed into the utility system. These issues are discussed in section 2.2.4 below.

2.2.3 Regulatory Treatment

a) Cross-subsidization issues

As discussed previously, some jurisdictions have specified NM through legislation. In those instances the enacting law may specify different rules than would otherwise be applied by the relevant regulator. For example, laws enacting FIT programs may offer different rates, allow cross-subsidization or simplified connection requirements as part of a policy goal of encouraging renewable generation. In other instances, laws enabling NM have directed the utility regulator to develop a NM policy without stipulating other requirements. As discussed in the introduction, these differences in the strategy behind NM accounts for many of the differences found in NM policies in different jurisdictions.

The most common regulatory concern with NM relates to possible cross-subsidization issues; whether transmission and distribution costs attributable to NM customers are transferred to

[37] SaskPower, Net Metering and Small Power Producers, 2010. http://www.organicconnections.ca/archives/conference2010/docs/OC%20pdf%20presentations2/Loughran.pdf

[38] BC Hydro, Net Metering Evaluation Report No. 3 – April 30, 2013

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non-NM customers. A small level of cross-subsidization can be expected to arise with respect to general administration and overhead costs including metering and program administration costs. Cross-subsidization issues have been raised by interveners in a number of regulatory reviews of NM policies.

Varying levels of cross-subsidization are found in virtually all jurisdictions, both between customers in rate classes or with other customer characteristics. In some instances, this cross subsidization is permitted to support other policy objectives. For example, in the territories (YK and NWT), legislation requires the crown utilities to supply electricity to communities not served by the local investor-owned utility (IOU). While these communities are largely supplied by more expensive diesel generation rather than from hydraulic generation which supplies the territorial system, the retail prices paid by customers in these communities are maintained at the same level as communities connected to the main system.

In most of the jurisdictions reviewed the potential financial impact on non-NM customers is expected to be very small given the small number of NM customers and the limited amount of generation contributed to the system. Some jurisdictions have changed their NM requirements in order to manage cross-subsidization. For example, in BC a 50kW limit was imposed in 2005 to reduce potential cost-shifting to non-NM customers. In its *2013 Net Metering Report No. 3*, BC Hydro noted that the capacity installed by NM customers is too small to result in any appreciable avoided cost benefits to BC Hydro and other ratepayers. BC Hydro also highlighted the degree to which the simplified application process has expedited the application process, reduced application times, and reduced overhead costs. In 2014, the British Columbia Utilities Commission ruled to increase the capacity limit to 100kW[39]. BCUC noted that given the legislative and regulatory emphasis on clean energy, it believed that lowering participation barriers was of most importance, and proceeded to increase the limit from 50kW to 100kW.

In some US States, declining solar PV costs and rising electricity rates have led to higher penetrations of NM and an associated concern over cross-subsidization. In 2013, the Arizona Public Service Company (APS) filed an application with the Arizona Corporation Commission (ACC), the regulator, to obtain approval for a 'cost-shift solution' –meant to address the increasing levels of cross-subsidization[40]. APS reported that for the years 2012-2013, it saw an average of 500 NM applications per month, and as of June 2013 it had 18,000 NM customers. APS argued that this was the result of state and federal incentives for NM, and the NM rate structure which provided NM customers an annual cash payment for excess generation. APS determined that on average, the cost shift from each NM customers to non-NM customers was

[39] BCUC Final Decision, Amendment to Rate Schedule 1289 Net Metering Service, July 25, 2014.
[40] APS Application for approval of Net Metering Cost Shift Solution, July 2013.

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of approximately $1,000 per year, such that in the current year the total cost shift to non-NM customers was of $18M.

The Idaho Power Company (IPC), in its 2013 Net Metering Report[41], identified that cross-subsidization was especially predominant within the Residential and Small General Service classes (R & SGS). IPC recounted that in the current bill structure, these two classes are billed through a $5 basic charge plus the volumetric energy rate. IPC then noted that their fixed-customer related costs for R & SGS were $20.92 and $22.49, respectively, and since these two customer classes are charged a flat monthly fee of $5, the majority of IPC's fixed-customer related costs are recovered through volumetric charges. Under this rate design, NM customers reducing their volumetric consumption would not be contributing fairly to the share of fixed costs. IPC concluded that at the current participation rates, it did not believe cross-subsidization was impacting customer rates. However, since rates were not design to recover the costs of providing a NM program, the current rate structure is unsustainable.

The Oregon PUC expressed its worries for cross-subsidization in its May 2014 draft report on solar programs[42]. The PUC noted that the economic potential for solar from NM would be limited as a result of the cost shifting of a utility's fixed costs from NM customers to non-NM customers; *"Net metering customers enjoy a reduced electric bill, but in doing so they avoid paying some of these fixed costs. The Utility must recover them from other ratepayers"*. The PUC concluded that, given the very limited state-wide capacity of distributed solar generation, cross-subsidization is of small concern in Oregon.

In January 2014 the South Carolina Public Utilities Review Committee released its *Distributed Energy Resources Report*[43]. The Committee identified that a utility's fixed costs represent 63% of their total service costs, and only 37% are variable costs. However, in the current residential rate design only 8% accounts for a basic, fixed charge, while 92% are recovered through volumetric rates. As a result, NM participation results in under-compensation of fixed costs to the utility. In Nevada, for example, there was a concern that the tariff provided for power supplied from NM installations (the "*Renewable Generations*" incentive) was too generous and combined with other NM rules resulted in cross-subsidization by other customers. Over 3,300 individual systems with over 60 MW of installed capacity (over 80% from PV systems) had enrolled in the program as of the end of 2013 and capacity installed under the system was projected to increase to over 230 MW by 2016[44]. The PUC of Nevada retained Environmental Economics (E3) to analyse the impacts of NM and answer a series of questions regarding potential cross-subsidization. The study concluded that due to the program design and

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41 Idaho Power Company, Annual Net Metering Status Report, February 28 2014.

42 Public Utility Commission of Oregon, Investigation into the Effectiveness of Solar Programs in Oregon, May 2014

43 South Carolina Public Utilities Review Committee, Distributed Energy Resources Report, January 2014

44 Nevada Net Energy Metering Impacts Evaluation, Prepared for: State of Nevada Public Utilities Commission, Energy and Environmental Economics (E3), Inc., July 2014, page 2.

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incentives offered, there was a significant shift from NM customers to non-participating customers prior to 2014. Looking forward however, the study determined that "*By 2016, assuming all of the reforms occur, non-participants will be approximately indifferent to customers that do install NM generation*" [45]. The implication of the report is that the issue of cross-subsidization is strongly related to the level of incentive, if any, offered for power produced from NM systems.

b) Regulators' analyses and rulings on net metering

Regulators have reviewed NM in several of the jurisdictions addressed in this study These reviews have included both program reviews in advance of launching a NM policy and periodic reviews of on-going programs.

In its final approval to adopt a NM program[46] the PUB-NWT identified a number of program elements that had potential to cause rate impacts as it moved towards adopting the NM program:

- Meter and metering costs,
- Customer communications/administration,
- Incremental costs from real-time monitoring of projects,
- Planning for new generation capacity, from a firm-capacity perspective,
- Fixed costs for generation/transmission/distribution not recovered due to netting, and
- Compensation of hydro customers at a rate reflective of displaced diesel and hydro.

The PUB-NWT concluded that these costs could be assessed more fully at Phase 2 of the 2014/15 rate application process.

As part of its decision the PUB-NWT:

- Ruled against setting rolling reset dates arguing that it would significantly increase the administrative burden for tracking and managing credits and dates.

- Found that NM customers in hydro communities would be compensated at a rate reflective of both displaced diesel and hydro generation. It acknowledged that this would result in some misallocation of costs but expected that the difference would be `

- Ruled that all NM projects are exempted from a standby service charge developed to provide NM customers a fair allocation of costs to maintain diesel generation to provide standby service to them, and to protect other customers from subsidizing NM

[45] Nevada Net Energy Metering Impacts Evaluation, E3, page 24. The reforms referred to involved issues such as the ratio of additional credits given for electricity from renewable source under the State's Renewable Portfolio Standard.
[46] NWT Public Utilities Board, 2014 Decision Re: Net Metering Application

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customers' fair share of standby generation. NTPC's reasoning for dropping the charge was that given a 5kW limit, customers would still purchase a material portion of their electricity from the grid, thereby contributing to those costs.

In most jurisdictions reviewed, the customer generally pays for the incremental metering cost and may pay for any required technical review or safety inspection. In Canada all of the jurisdictions with a NM policy pay for on-going meter reading and program administration costs.

The Yukon Utilities Board (YUB), prior to final approval of its NM policy, reassessed its draft policy[47]. The YUB decided against a credit expiration date, and approved a compensation scheme in which every kWh of excess electricity, rather than becoming a credit after each month, is paid at the avoided cost of generation once a year. The YUB notes that this annual metering and compensation approach encourages customer energy efficiency given that every kWh exported is summed into the annual payout, so that less energy usage by the customer directly affects the annual payout (unlike with monthly metering, which generally will create a scenario where credits will be used up month after month).

In Arizona, in response to APS's Cost Shift application, the ACC ordered a temporary $0.70/kW charge -for all residential NM systems installed from 2014 onwards- as a short term solution to cross subsidization until the next rate setting period[48]. In its evaluation the ACC noted that a series of interveners had suggested introducing a service, demand, or standby charge. The ACC argued that because residential rates are typically designed to recover much of the utility's fixed costs through volumetric energy rates, NM customers were paying less for those fixed costs. The additional fixed costs would be picked up by non-NM customers either through higher energy rates or through APS's Fixed Cost Lost Recovery mechanism.

In Idaho, on November 2012 IPC filed an application with the IPUC as its cumulative NM capacity neared its previously-held 2.9MW subscription limit[49].

IPC proposed:

1. *Subscription limit*: doubling its limit to 5.8MW
2. *Rate design*: an increase to its residential basic charge from $5 to $22.49 -and as result of this increase- a decrease in the residential energy charge down to 4.85c/kWh, and

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[47] Department of Energy, Mines and Resources of Yukon, Net Metering Policy, Draft For Consultation, Feb 2011

[48] Arizona Corporation Commission, Decision No. 74202, APS' Application for Approval of Net Metering Cost Shift Solution, Dec 3, 2013
http://www.dsireusa.org/documents/Incentives/AZ%20Final%20Order%2074202.pdf

[49] Idaho Power Company, Application for Net Metering Service, Case No. IPC-E-12-27, Nov 30, 2012
http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1227/20121130APPLICATION.PDF

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3. *Annual payout*: replacing the previously-held annual cash payment with a credit expiry date of December 31

In its decision, the IPUC denied nearly all of IPC's proposal[50]. The IPUC ruled that even the proposed 5.8MW subscription limit "[would] disrupt and have a chilling effect" on NM, so it decided to eliminate the subscription limit altogether. Regarding the rate design, the IPUC noted that while *"[NM customers] do escape a portion of the fixed costs and shift the cost burden to other customers in their class…more work needs to be done to establish the correct customer charge for [participants]"*. The IPUC found that IPC's rate-design proposal imposed an overwhelming change. Finally, with regards to eliminating the annual payout, the IPUC stated: *"while we want to encourage net metering, we believe financial credit or payment may incent potential net metering customer to overbuild their system"*. The IPUC eliminated the annual payout and instituted a system where kWh credits are carried forward indefinitely, without an expiration date.

In 2008, the South Carolina Energy Office (SCEO) was asked to recommend guidelines for IOUs to establish NM programs. In its report[51], the SCEO asked -as a first step- that there be a clear separation of NM and power purchase programs. The following were some of SCEO's recommendations:

1. Standardize NM program structure across utilities
2. For residential customers, modify the IOU flat rate to reflect 1:1 standard retail rates for excess energy credits
3. Acknowledge that recommendation #2 may create cross-subsidization, and allow utilities to recover these costs
4. Eliminate stand-by charges
5. Allow NM customers to retain ownership of renewable energy credits
6. Require annual reporting, and formally revisit the NM process within 4 years

In Vermont, legislative bills -in 2013 and 2014- required the Public Service Department (PSD) to conduct a study on the existence and degree of cross-subsidization. Both PSD reports[52] followed the same cost-benefit analysis structure and framework over a 20 year period, from a ratepayer and societal perspective. The reports assessed the deployment of small and large solar (non- and tracking) and wind systems in the territories of VT's 17 utilities; this, in order to perceive the effect of each utility's rate structures on costs and benefits. The 2014 study concluded that: *"the aggregate net cost over 20 years to non-participating ratepayers due to net metering under the current policy framework is close to zero, and there may be a net benefit"*. The PSD also stated that *"while rates strive to assign costs to those who cause them, this cannot be done exactly. The classic example [being] the comparison of urban and rural rates"*. The PSD recommended that for

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[50] Idaho Public Utilities Commission, Final Order – Case No. IPC-E-12-27. July 3, 2013.
[51] South Carolina Energy Office, Net Metering Report, Dec 30, 2008
[52] Vermont Public Service Department, Evaluation of Net Metering in Vermont Conducted Pursuant to Act 99 of 2014, Oct 1, 2014

2016 onwards the Public Service Board, the regulator, consider potential changes to the utilities' NM program structure which may benefit the state as a whole. The intent of the 2014 legislative bill[53] is to establish a revised NM program by 2017.

2.2.4 NM Impacts

a) Net metering rate structures

Settlement for electricity consumed by and produced by NM installations typically involves two different but related processes. The first process involves the regular billing process for the NM customer, which is discussed in part b) below. The second process involves settlement or compensating the customer for any excess generation, in excess of the customer which is supplied to the utility system, discussed in part c) below. The rates applicable in each process are described in the appropriate section below.

All of the US jurisdictions reviewed offered customers a choice of at least two different tariffs under the label of NM, net billing, or self-generation. In AZ, the regulations permit the electric utilities to use avoided-cost rates, which may be differentiated seasonally and by time-of-day.

b) Monthly bill determination

In most jurisdictions, customers with NM installations are billed as part of regularly scheduled billing cycles, generally monthly or bi-monthly, based on their net electricity consumption. In all of the jurisdictions reviewed, NM customers are billed for any basic monthly charges included in the rate schedule applicable to their service but are billed volumetric charges based on the net volume of electricity consumed. Common industry practice is to allow customers to carry over kWh credits from one billing cycle to the next for up to one year. The treatment and settlement for any excess generation fed into the utility system is discussed in the following section (*Compensation for excess generation*). Information on the application of taxes, such as the HST, was only found for one Canadian jurisdiction, which indicated that HST is charged based on the total kWh delivered by the utility, rather than the net amount over the billing period.

All of the US jurisdictions reviewed charge NM customers a basic monthly charge and base volumetric charges on the net electricity consumed. In all, but two cases, customers are allowed to carry over kWh credits from one billing cycle to the next for up to one year.

- In Idaho, IPC –the state's largest IOU- allows its customers to carry over kWh credits indefinitely. In 2012, IPC filed an application with the IPUC asking to replace the annual financial payout with a credit expiry date of December 31. In July 2013, the

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[53] Vermont, Bill H.702 (Act 99)

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IPUC ruled that it was *"fair, just and reasonable for the kWh credit to indefinitely carry forward to offset future bills"*[54], such that IPC customers' excess kWh credits never expire.

- In Oregon, where the PUC established separate NM program for public utilities and IOUs, Tillamook Public Utility District is the only utility that allows for credits to be carried indefinitely.[55]

c) Compensation for excess generation

The rate paid to NM customers for excess power fed into the utility system differs by jurisdiction. In some instances, excess kWh fed into the utility system are credited to the customer's bill, effectively treating kWh drawn from the system and those fed into the system as equivalent. Eight Canadian jurisdictions credit customers for excess generation at the applicable retail rate (AB, SK, ON, NB, NS, PEI and NWT); though in some of these jurisdictions excess generation credits may expire after some pre-defined period (as discussed in "d) Process for Annual settlement").

Of those jurisdictions that offer customers a cash payment as part of an annual settlement process, (in Canada - AB, BC, MB, NS and YK), two (NS and AB) compensate customers at the applicable retail rate[56], and two (MB and YK) pay the customer at the utility's avoided cost. In jurisdictions with a FIT (ON) or Standard Offer Program (BC), the customer is compensated based on rates established under those programs.

In the US, different states have set up different settlement processes. Two jurisdictions (AZ and OR) provide a cash payment, calculated based on avoided costs, at the end of a 12 month period. Four others (ID, SC, WA and VT) do not pay for any annual balance in excess generation. Oregon has developed a unique solution. The State requires its IOUs and public utilities to provide the payment to the utilities' low income program. In F2013, OR's two IOUs (Portland General Electric[57] and Pacific Corp[58]) collected a total of 1,124MWh of excess credits which, transferred at the avoided costs rate, resulted in a $34K contribution to Oregon Heat's low-income participants.

[54] Idaho Public Utilities Commission, Final Order – Case No. IPC-E-12-27. July 3, 2013, pg. 13
[55] Aaron Lindenbaum, Net Metering in Oregon: Policy vs. Practice, September 21 2012
[56] In AB this applies only to residential customers.
[57] Portland General Electric, 2014 Unused Energy Report for Net Metering Facilities in 2013, July 1, 2014
[58] Pacific Power, Report on Excess Energy from Net Metering Facilities, June 18, 2013

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d) Process for annual settlement

In all of the jurisdictions reviewed, the customer is compensated for all kWh fed into the utility system providing that they do not exceed the customer's consumption over a prescribed period (normally 12 months). In most of the jurisdictions reviewed, settlement for unused generation credits is carried out annually. The timing of the annual settlement varies by jurisdiction but is often scheduled in the "shoulder months" (spring or fall).

In Canada, about half of the jurisdictions that have a net metering policy offer customers a cash payment at the end of a 12 month period (AB, BC, MB, NS and YK). In the other half of the jurisdictions, any unused credit is absorbed by the utility at the end of the designated period[59]. In the US, one jurisdiction (AZ) offers customers a cash payment, three jurisdictions (SC, VT, WA) has the utility absorb the unused credit, one (OR) socializes the credit into the "Oregon Heat low-income program", and one (ID) has a mixture of treatments (Idaho's IPC allows indefinite carryover of credits)[60].

e) Responsibility for associated net metering costs (e.g. engineering studies, distribution equipment upgrades, metering upgrades, related billing costs)

In all of the jurisdictions reviewed, customers are generally responsible for paying for additional costs associated with a NM installation, while the utility absorbs the costs of additional meter reading, billing and administration associated with NM reviews and approvals. Jurisdictions have made different decisions regarding the allocation of some of the other associated costs.

2.2.5 Participation / Uptake

Customer participation rates have varied widely, in part reflecting different policy objectives underlying the NM policy. In many cases the participation in NM is not publicly reported or is combined with participation rates for FIT or other initiatives.

In Canada, uptake rates for jurisdictions which reported NM participation (AB, BC, NS, PEI, SK and NWT) ranged from 200kW to 4.5MW in installed capacity, and ranged from 0.01% to 0.16% as a percentage of the jurisdictions' installed capacity. Wind and solar PV projects are by and large the technologies of choice for NM projects. In ON, the microFIT program (<10kW) reached 167.3MW in cumulative capacity, or 0.54% of the provincial installed capacity. Information on program uptake was unavailable for three jurisdiction (MB, NB and QC). YK, whose program commenced in February 2014, has not yet reported participation and capacity uptake from NM.

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[59] The designated period is 12 months in all jurisdictions except Quebec, which uses a 24 month settlement period.
[60] Idaho Power allows indefinite carryover of credits. Two other Idaho utilities (Avista and Rocky Mountain) absorb the credit.

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The US jurisdictions reviewed were found to have higher levels of program participation than were found for Canadian jurisdictions; both in term of installed capacity and number of NM customers. In most US jurisdictions, only IOUs are required to report the uptake of NM participation to their regulators. The reported NM participation ranged from 2.97MW to 375MW in installed capacity, and ranged from 0.8% to 5.2% as a percentage of the states' installed capacity.

Uptake rates (on a per year basis) for each Canadian and US jurisdictions are found in Table 3. The rates are for the last reported year of NM information, and are reflective of the growth maturity of each jurisdiction.

Table 3: Annual Uptake Rates (MW and Projects per Year)

		Program since	Last reported year	Uptake[61]	Uptake (projects)	Rate [62]	Rate (projects/yr.)	Uptake as % of load[63]
Canada	AB	2009	2013	4.5 MW	888	1.4 MW/year	249	0.03%
	BC	2005	F2013	1.1 MW	228	0.31 MW/year	70	0.01%
	MB	-	-	-	-	-	-	-
	NB	2005	-	-	-	-	-	-
	NS	2005	2013	1.2 MW	157	0.19 MW/year	30	0.03%
	ON[64]	2006	2013	167.3 MW[65]	19,275	30.1 MW/year	3,501	0.54%
	PEI[66]	2005	2012	200 kW[67]	-	-	-	0.05%
	QC	2004	-	-	-	-	-	-
	SK[68]	2007	2010	5.1 MW	584	0.96 MW/year	100	0.12%
	YK	2014	-	Not yet known	-	-	-	-
	NWT[69]	2014	F2014	202 kW[70]		67 kW/year	-	0.16%
United States	AZ[71]	2006	2013	375 MW (149 MW res.)	17,696 (17,024 res.)	106 MW/year (49 MW/year res.)	6,902 (6,722 res.)	4%[10] (1.6%)
	ID	1983	2013	2.97 MW[72]	428	0.45 MW/year	78	0.08%[11]
	OR	1999	2013	56.6 MW	6,882	12.6 MW/year	1,086	0.36%
	SC[73]	2008	2013	4.6 MW	299	-	207	0.02%
	VT	1998	2013	63.99 MW	4,620	14.8 MW/year	1,027	5.2%
	WA[74]	1998	2013	27.1 MW	5,600	8.0 MW/year	1,550	0.09%

61 The Uptake date may not be reflective of the last reported year. Uptake may be reflective of partial 2014 data. See Appendix A for exact dates

62 Uptake rates (in MW/year and projects/year) in the last reported year

63 Calculated as % of a jurisdiction's total installed capacity as of Dec 31, 2012 for Canada, and July 2014 for the US

64 Ontario data is taken from microFIT projects from Jan 7, 2013 to Jan 6, 2014

65 Data is representative of microFIT program (for <10kW), and accumulates projects from microFIT 1.3-1.6, 2.0, and 3.0 as of Oct 3, 2014

66 Not enough information available for PEI to determine uptake rates

67 Value reported from four community based projects that installed 50kW turbines

68 Estimate given 1.3MW in 2010 (target was 1.1MW) and 2017 estimate of 8MW

69 In the NWT, a net billing pilot had been in effect since 2010. The rates provided are for the 3 year average F2011-2014. Participation rates are not known

70 This value excludes projects from the hydro zone (only 3 customers as of July 31, 2013)

71 Data reported only representative of the Arizona Public Service Company. Uptake in MW is representative of Dec 31, 2013, uptake in number of projects is as of June 2013

72 Data reported only representative of Idaho Power Company (IPC)

73 The SC uptake rate (MW/year) is not known. SC utilities are only required to include the number of net metering customers, not capacity.

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3 Considerations for a Provincial Net Metering Policy

The following section describes how Navigant determined "best practices" for the purpose of this study and offers items to be considered in the development of a NM policy for Newfoundland and Labrador. These considerations, offered for analysis by the DNR and the Steering Committee which has guided this study, are intended to be directional rather than prescriptive and recognize that the final policy design will be developed in consultation with the Steering Committee and other stakeholders.

3.1 Best Practices

As part of the study, Navigant was asked to identify "best practices" for NM policies. No examples of recommended Best Practices specific to Canada were identified, although Measurement Canada (MC) has published a policy regarding electric meters for net metering[75]. The MC policy focusses on requirements for electric meters and metering configurations but does not address the broader issues of eligibility limits or settlement.

In the US, the Interstate Renewable Energy Council (IREC)[76], which promotes the use of renewable and clean energy, has published a *Model Net Metering Rule* since 2003. The model rule sets out what the renewable energy industry believes represent best practices in NM policies[77]. The US DOE, which includes the IREC Model Rule on their website as a "*best practice*"," has summarized the recommended elements of the IREC Model Rule as:

- "All utilities (including municipal utilities and electric cooperatives) should be subject to the state policy.
- All customer classes should be eligible.
- The individual system capacity should not exceed the customer's service entrance capacity. Otherwise, there should be no individual system capacity limit.
- There should be no aggregate system capacity limit.
- Any customer net excess generation at the end of a billing period should be credited to the customer's next bill as a kWh credit (i.e., at the utility's full retail rate) indefinitely, until the customer leaves the utility's system.
- Utilities should not be permitted to impose an application fee for NM.

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[74] Project numbers and uptake rates (MW/year and projects/year) are reflective of only solar PV installations, which includes a small number of commercial projects >100kW

[75] Measurement Canada, E-27 — Policy on the use of Electricity Meters in Net Metering Applications, http://www.ic.gc.ca/eic/site/mc-mc.nsf/eng/lm00030.html.

[76] IREC is a well-recognized, non-profit organization that educates and promotes the uptake of renewable and clean energy. IREC publishes regulatory policy best-practices reports, offers training programs, publications, accreditation and certification programs.

[77] Interstate Renewable Energy Council (IRE C), Model Net Metering Rules: 2009 Edition,

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- Utilities should not be permitted to impose any charges or fees for NM that would not apply if the customer were not engaged in NM.
- Utilities should not be permitted to force customers to switch to a different tariff. Customers should have the option to switch to a different tariff, including a time-of-use tariffs, if they choose to do so. If a customer is on the time-of-use tariff, they should be credited for the appropriate time-of-use period in the billing period.
- Customers should have ownership of any renewable-energy credits (RECs) associated with the customer's electricity generation.
- Customers should be permitted to offset load measured by multiple meters on the same property using a centrally-located system.
- The state public utilities commission should adopt comprehensive interconnection standards for customer-sited systems."

While this Model Rule identifies "best practices" from the stand-point of renewable energy producers and are recognized by agencies such as the US Department of Energy, they do not necessarily align with the context in NL.

While some "best practices" can be judged from standard industry practices, in many cases the "best practice" depends on what is appropriate for the context in which the policy is to be implemented considering the policy objectives to be met and the starting conditions. As discussed, the NL system has one of the highest proportions of renewable hydraulic generation of any jurisdiction in North America[78]. As a result, the focus of a NM policy in NL may differ from that in other jurisdictions.

In its 2007 Energy Plan the Government of Newfoundland and Labrador committed to develop and implement a NM policy for small-scale renewable energy sources. We have interpreted this focus on small scale, renewable sources and providing a regulatory framework for these customers as key elements to consider when developing a NM policy for the Province and recommends that the following policy elements be considered in developing a NM policy for the Province.

[78] As indicated in the Introduction, NL anticipates that after Muskrat Falls and the associated transmission ties come on line the province will generate approximately 98% of its electricity from renewable sources. In Canada and the US, only Manitoba, Quebec, BC, Washington and Oregon come close to this level of renewable supply. In most other provinces, territories and states fossil fuels supply a significant portion of generation. Across the US, coal supplies about 40% of generation, with natural gas supplying just under 30%. (see US EPA, US Fuel Mix 2001-2013, http://www.epa.gov/cleanenergy/energy-and-you/)

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3.2 Policy Considerations

Navigant recommends that a NM policy for NL address the following issues.

- Eligibility Criteria
  - Types of generation or energy sources permitted,
  - Customer class,
  - Limits on system capacity, and,
  - Limitations relative to customer load.
- Connection Requirements, including the need for a technical review, standards to be applied for generator connections, safety inspections, etc.
- Meter aggregation rules
- Allocation of costs for technical reviews, incremental meter costs, distribution system upgrades required, billing and administrative costs, etc.
- Rates applicable to net consumption and excess generation
- Settlement process to be used for excess generation supplied to the system
- Subscription limits or "Aggregate Capacity Limit" for the program as a whole
- Treatment of any credits that may be associated with the generation (Renewable Energy Credits, carbon credits, etc.)

Based on our review of industry practices with respect to Net Metering and the NL policy context we offer the following recommendations for consideration.

1. Eligibility Criteria:

   i. In keeping with the Government's policy direction, it is recommended that NM be made available for small-scale renewable resources.

   ii. It is recommended that NM be made available for customer classes which cover "homeowners and small business operators"[79] and for customer systems sizes consistent with the emphasis on small scale. It may be appropriate to interpret this limitation differently for connections for different portions of the system (i.e. the Island system and isolated and coastal communities served by diesel systems) based on differing system capabilities; with a lower limits applied in smaller diesel systems.

   iii. Navigant suggests that it would be appropriate to adopt the IREC model rule requirement that "*individual system capacity should not exceed the customer's service entrance capacity*" or jurisdictions which limit the connected generation relative to the customer's load (i.e. Arizona limits generation to 125% of the customer's load). This would be consistent with the Government's stated policy goal of

[79] Newfoundland and Labrador, *Focusing Our Energy* – Energy Plan, page 40.

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allowing residential and small business "*to install small generation units to produce power for themselves and feed some back in the system when they produce more than they need*"[80]. Limiting system capacity to the customer's load will also help limit issues relating to settlement for excess generation from NM systems.

2. It is recommended that transparent requirements for connecting NM customers be established by the utilities and made publically available for potential NM customers prior to implementing the policy. These requirements would be expected to address the need for review of connection requests by the utility. We anticipate that the utilities will be able to adopt existing standards for customer and generator connections for this purpose, but it is recommended that consideration be given to means of streamlining these processes in order to provide a timely response and minimize administrative costs. Navigant suggests that NL consult with BC Hydro regarding their experience in streamlining their processes.

3. Navigant suggests that meter aggregation not be permitted under the policy, though there may be reason to allow multiple meters on the same property to be consolidated as recommended by IREC. Excluding aggregation is consistent with most other jurisdictions and will help limit administrative issues, including settlement issues that may arise if aggregation is permitted.

4. The NM policy should clearly articulate responsibility for different costs associated with NM installations. While there is no standard industry practice, most jurisdictions require the customer to pay for additional meter costs and any permits required. We concur with the IREC recommendation that under a well-designed program, limited to small-scale generation, the costs of technical reviews of connection requests, incremental meter reading and billing costs, and administrative costs should be negligible over the rate base, however, consultation with the utilities is recommended.

   It should also be noted that some customer connection requests could require distribution system upgrades to accommodate. In these instances, we recommend that the utility be provided discretion as to whether a connection request can be accommodated and whether the costs of any required upgrades should be recovered from the NM customer.

5. Settlement for NM installations can be managed in several ways. Navigant suggests that NL consult with the utilities as to the most efficient and equitable solution. We recommend that the customer's net consumption be billed using the tariffs which would normally apply to a customer of the same size, type and location and that the

[80] *Focusing Our Energy*, page 24.

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customer be compensated for excess power at the same rates (i.e. a periodic settlement process be implemented and any the customer be compensated for any excess generation).

With regards to settlement for excess generation produced from NM systems and fed into the utility system we suggest two options be considered.

i. Credit “net excess generation at the end of a billing period” to the customer’s next bill as a kWh credit (as recommended by IREC). This offers a simple solution if NM systems are limited to be approximately the same size as the customer’s load. It is recommended that if this approach is taken that these accounts be monitored annually to identify any accounts which are developing a significant credit over a 12-month period.

ii. Separately track net excess generation for NM installations and settle annually with a cash payment or bill credit. It is anticipated that this would be an off-line process separate from the utility’s normal billing process and would therefore add some administrative costs. The alternative, used by a number of utilities of simply absorbing any excess generation would serve to discourage oversizing of customer generation but is likely to be perceived as inequitable by customers.

   Under the second approach a separate decision will be required regarding the rate at which to compensate for excess generation. One solution is to calculate any resulting credit at the rates normally applicable to the account. This has the advantage of simplicity and provides a settlement that is consistent with the credit normally provided in “netting” at the meter. The drawback of this approach is that it may result in some cross subsidization[81] if the applicable rates differ from avoided costs. If avoided costs are expected to differ significantly from applicable rates, then the use of avoided costs in the settlement process will reduce the risk of cross-subsidization.

6. Navigant does not expect that an overall subscription limit for the program as a whole is required for NL given the policy objective and Provincial context. We recommend, however, that the utilities be encouraged to monitor the response to the policy and provided the opportunity to recommend an overall capacity limit should the need develop.

7. While there is not currently a significant market for Renewable Energy Credits or Carbon Credits that could be associated with small-scale renewable generation, we

[81] Note that depending on how rates differ from avoided costs, the NM customer may subsidize other customers or be subsidized by other customers.

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recommend that the policy be clear in stating that the system owner would retain these credits.

8. As discussed, NM policies have been introduced in different jurisdictions by legislation, through government direction to regulators, and voluntarily by utilities. We suggest that the most appropriate path for NL would be to have a NM policy developed under the auspices of the PUB, either directly as part of a PUB process or by directing the utilities to develop a policy for PUB approval. This approach would be consistent with the Government's statement that it will ensure that "*regulatory support is in place for customers who wish to develop these alternatives*"[82]. A policy developed by the PUB would also be subject to its normal considerations that rates be "just and reasonable" and that the service provided be "safe and reliable".

   We understand, however, that the PUB may be restricted by its mandate if it deems that there is some risk of cross-subsidization. We therefore recommend that Natural Resources discuss the proposed approach to a NM Policy with the PUB to determine if it would be acceptable. If it is determined that concerns about potential cross subsidization would preclude the PUB from implementing a NM policy, then legislation should be considered to authorize the PUB to implement NM.

[82] *Focusing Our Energy*, page 40.

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Appendix A: Summary of Net Metering Policies by Jurisdiction

NM Jurisdictional Review

Jurisdiction

Alberta

Micro-Generation

Drivers for NM

Driving force:
The AB Government passed the Micro-Generation (MG) Regulation (27/2008) on Feb 2008, under the Electric Utilities Act. The Alberta Utilities Commission (AUC) implements the regulation, and hence developed *Rule 024 – Micro-Generation*. The regulation came into effect January 2009, then was extended on Dec 2013 to Dec 31, 2015.

Market: Deregulated, wholesale market; system owned/operated by IOUs, munis, wire service providers (WSP), retailers

Generation Capacity:

Sept 2014	MW	%
Coal	6,258	43%
Gas	5,812	40%
Hydro	900	6%
Waste Heat	86	1%
Fuel Oil	12	0%
Renewable	1,530	10%
Total	14,598	100%

Program Design/Framework

Legislative Consideration:
Electric Utilities Act:
- The distribution tariff is determined by each distribution system owner (not provincially dictated or likewise)
- Rate tariffs are determined –at a first level- by the distribution system owner, followed by the retailer –at a second level.
- *"A customer has the right to obtain retail electricity services from a retailer"* (WSP)

Micro-Generation Regulation:
- Retailer acts as participant in AESO's market
- Article 7(5) states *"Unless a [MG] and a retailer agree in writing to different compensation….".* This effectively allows retailers to set up a subsidy-type compensation scheme (i.e. FIT). Multiple retailers (at least 13) created the Light Up Alberta program wherein MGs where paid 15c/kWh for their renewable electricity exported. The Alberta Electricity System Operator (AESO) and the Ministry pushed back, but the regulation has not changed the language.

Eligibility Requirements:
- Must be renewable resources or alternative energy, meaning:
  - Solar, wind, hydro, fuel cell, geothermal, biomass, or other source with GHG intensity less than 418kg/MWh
  - Product having EcoLogo certification
- <1MW
- (Sized to needs) Nominal capacity does not exceed the rating of the customer's service. AUC uses the transformer rating –that serves a customer- to determine the max capacity of a customer's MG system.
- Meter Aggregation**:** unit located on or adjacent (if owned/leased) to customer's site
- Subscription limit: Not included

Implementation (Application Process):
- Submit Micro-Generation application form
- Include site plan, single line diagram, system certification
- Obtain *WSP/PUC approval* as required (see below)
- Electrical inspection
- Meter installation/modification

WSP/PUC Approval:
- Customers (<1MW) don't need to file an application to the AUC, only submit application directly to the WSP - if (1) no person is adversely affected, (2) complies with AUC Rule 012: Noise Control [required for wind projects], and (3) no effect on the environment.

If fails to comply with (1)-(3), customer must follow Rule 007-Section 4 procedure (PUC approval required).

Customer & Program Costs/Benefits

Bill Determination/Rate Structure
- Provides for a credit for the excess electricity sent into the grid.
- Bill includes associated distribution charges, as well, monthly administration, and billing
- A credit may be carried forward for up to 12 months to offset a charge for any month
- At least once in each calendar year, micro-generators are provided a **payment** for any unused credits accumulated
  - Small MG (0-150kW): compensated at that retailer's retail energy rate and on a monthly electricity bill
  - Large MG (150-1,000kW): compensated at the hourly pool price for each hour in the billing period

Responsibility for associated NM costs
Customer Costs:
- Monthly base charge
- Municipal permits

Utility Costs
- WSP is responsible for the cost of the meter, installation, metering
- Cost of connecting MGs are borne by the WSP, and recovered by the WSP's customer rates (unless connection costs are 'extra-ordinary')
- MG distribution charges applied to MG are only for the electricity

Regulatory Treatment

Cross Subsidization Issues:
- Meter, metering, installation costs are added to rate base, and recovered from all customers

AUC Evaluation [1]:
- Under Rule 021, retailers report the retail rate to the ISO to recover costs through the transmission tariff.
- If due to Article 7(5) of the regulation, a retailer negotiates with a customer a higher price than the retail rate, the retailer cannot report this contracted price to the ISO to have all its electricity customers subsidize the higher price paid to micro-generators.
- In this case, the retailer is responsible for paying the premium (the difference from the micro-gen price and the retail rate) to the micro-generation customer. The retailer is not allowed to recover the premium from the ISO.

Other Information
Meter:
Alberta uses net billing which employs a meter with two registers - one for electricity fed to the grid and one for electricity taken from the grid. Having two registers allows micro-generators to keep track of how much electricity their system has generated.
- 0-150kW: bi-directional cumulative meter
- 150-1,000kW: bi-directional interval meter

Alberta Carbon Offset Credit System
- For emitter with >100K tCO2. Emitters must reduce by 12% their emissions per production unit. Emitter can purchase credits from any of the government-approved protocols.
- In 2013, the Protocol for Distributed Renewable Energy Generation (for micro generators was approved). With this protocol, micro-generators have the possibility of additional revenue.
- As of April 2014, there was interest in carbon credits purchased from micro-generators, but emitters are not using them because of –among a few reasons- potential tCO2 size (relative to larger renewable, EE projects in the GHG registry yielding 1,000s tCO2 credits)

HatSmart Renewable Energy Incentive
- Rebate program for Medicine Hat residents for 25% (up to $2,500) of installation costs of renewable energy systems.

NM Experience

(Jan 2014):
- 888 sites
- 4.5MW total

See Micro-Generation General Website, Q: How many micro-generators are there in Alberta?

Sources

Micro-Generation General Website:
http://www.energy.alberta.ca/Electricity/microgen.asp

Regulation:
http://www.qp.alberta.ca/1266.cfm?page=2008_027.cfm&leg_type=Regs&isbncln=9780779730308

Rule 024:
http://www.auc.ab.ca/acts-regulations-and-auc-rules/rules/Documents/Rule024.pdf

Application Guidelines:
http://www.auc.ab.ca/rule-development/micro-generation/Documents/Micro_Generation/MicroGeneratorApplication_Version1-3_20130705%20.pdf

Alberta Profile:
http://www.energy.alberta.ca/Electricity/682.asp
http://www.energy.alberta.ca/Electricity/microgen.asp

Carbon Offsets- Micro Generation Protocol (summary)
http://www1.agric.gov.ab.ca/$department/deptdocs.nsf/all/cl14883/$file/microgen4.pdf?OpenElement

Protocol for Distributed Renewable Energy Generation:
http://esrd.alberta.ca/focus/alberta-and-climate-change/regulating-greenhouse-gas-emissions/alberta-based-offset-credit-system/offset-credit-system-protocols/documents/8816.pdf

HatSmart Renewable Energy incentive:
http://www.hatsmart.ca/Residential%20Incentive%20Programs/Renewable%20Energy%20Installations/Purchase.asp

[1] Reporting of retail energy rate information in the micro-generation retailer summary transaction of AUC Rule 021
http://www.auc.ab.ca/news-room/bulletins/Bulletins/2014/Compliance%20Guide%202014-03-03.pdf

AUC Transformer Ruling:
http://www.auc.ab.ca/applications/decisions/Decisions/2012/2012-103.pdf

NAVIGANT

NM Jurisdictional Review

Jurisdiction

British Columbia

Net Metering (RS 1289)

Drivers for NM

Driving force:
In 2002, the BC Government's 2002 B.C Energy Plan, -through (Action #20) required 50% of new supply to come from clean electricity.
In July 2003, the BC Utilities Commission (BCUC) directed BC Hydro to file a NM application.
Since then BC Hydro, FortisBC, etc. have developed NM programs.

Market:
BC Hydro (1.2M customers) and FortisBC (0.1M). BC Hydro is vertically integrated, and regulated by BCUC.

Generation Capacity:

Dec 2012	MW	%
Gas	1,464	9%
Hydro	13,160	84%
Renewable	767	5%
Total	15,631	100%

Program Design/Framework

Legislative Considerations:
BCUC operating under the Utilities Commission Act:
- *"the commission must have due regard to the setting of a rate that…provides to the public utility for which the rate is set fair any reasonable return on any expenditure made by it…"*
- Expenses defined as *"to encourage public utilities to produce, generate and acquire electricity from clean or renewable sources"*

The Clean Energy Act, and BC Hydro IRPs have supported the development of renewable resources through RS1289 and the Standard Offer Program (SOP)

Clean Energy Act:
- *"to generate at least 93% of the electricity in British Columbia from clean or renewable resources"*
- *"To facilitate the achievement of one or more of British Columbia's energy objectives, the Lieutenant Governor in Council, by regulation, may require the authority to establish a feed-in tariff program"*

RS 1289 originally written in 2004, then amended in 2014.

Eligibility Requirements:
- 50kW (amended to 100kW on July 2014, after interveners challenged the 50kW limit when BC Hydro filled for an RS 1289 amendment in 2011)
- Residential or any General Service
- Clean or renewable resource (as defined by BC's Clean Energy Act)
- Meter aggregation: Unit must located on or adjacent (if owned/leased) to the customer's property
- Subscription limit: Not included

Implementation (Application Process):
If Simple NM Gen (<27kW, CSA certified, self-contained revenue metering):
- Submit a "Simple Net Metering Interconnection Application Form"
- No drawings required

Otherwise:
- Submit a "Complex Net Metering Interconnection Application Form", plus additional documents required
- Electric single-line diagram, site plan

Overall, 90% of projects are streamlined (skips engineering review) through the Simple NM Gen. application process. BC Hydro is considering introducing a streamlined process for standardized designs, rather than simply being qualified as a Simple NM based on technical requirements deemed 'too technical for the layperson'.

Customer & Program Costs/Benefits

Bill Determination/Rate Structure
- Excess energy is credited to customer's account and carried over.
- At the anniversary date, remaining credits paid through a **cash payout** at 9.99c/kWh
  - Reasoning for 9.99c/kWh: *"generally consistent with SOP prices"*; which varies from approximately 9.5 to 10.4c/kWh
- The overarching premise for 9.99c/kWh is rate simplicity (BC Hydro did not consider losses, upgrades costs, etc. –i.e. not cost-of-service)

Responsibility for associated net metering costs
Customer Costs:
- meter base, wiring, protection-isolation devices, disconnect switches, etc. (any equipment on the Customer's side of the delivery point)
- For >5kW (and if determined by BC); must also pay a Net Metering Site Acceptance Verification Fee
- Synchronous Generators; required to pay additional costs for interconnecting the generator relative to a non-sync generator (until July 2014 amendment used to require all costs)
- Similarly, for all generators >50kW will be required to pay additional costs relative to a generator <50kW (an intervener suggested that BC Hydro adopt the Alberta approach to only charge for 'extraordinary' connection costs)

Utility Costs:
- Meter, connection to grid
- RS 1289 F2013 administration costs: $125,000 (*Technical Review* only accounted for $2,000; this low costs for engineering review is significant in that it follows from having 90% of project streamlined through the simple application process)

Credits and Payments:
As of March 31, 2013:
- Customers received approximately 107MWh of credits.
- In F2012, BC Hydro delivered 29.5GWh to NM customers.
- BC Hydro also purchased 529MWh of surplus energy from 13 customers (with one customer accounted for 80% of purchases)
- The overarching conclusion is that in general the energy credits/kWh of payout only account for a tiny fraction of the electricity delivered by BC Hydro. Vast majority of customers are still highly dependent on grid.

Regulatory Treatment

Cross Subsidization Issues:
- Level of cross-subsidization is limited to meter, metering, program administration, and connection costs
- *"Given the minimal volume of RS 1289 energy, the financial impact on non-participating ratepayers is currently not significant and BC Hydro therefore does not have any pricing concerns"* [2]
- The BCUC first imposed the 50kW to limit potential for cross-subsidization

BC Hydro Analysis:
Three evaluation reports to date by BC Hydro (last on April 30, 2013).
- Due to 2014 amendment, BCUC has agreed with BC Hydro to produce a report in 2017, to allow for 2-3 years of experience with the amended program
- Cost of power: *"At this time, the installed capacity of RS 1289 generators and the volume of energy generated by those customers is simply too small to result in any appreciable avoided cost benefits to BC Hydro and other ratepayers, both in terms of the impact on BC Hydro's Load-Resource Balance and avoided system costs."* (BC Hydro 2013 conclusion)
- *"the impact of RS 1289 on the load is inconsequential"*
- *"BC Hydro agrees that if a supplier designs a standardized system [i.e. PV, micro Hydro] and BC Hydro has reviewed that system and is satisfied with it, any subsequent projects using the same design are likely to be resolved more expeditiously"* [1]; intention is to speed up the lengthy process, though BC Hydro states that interconnection impacts are drive by project size/location, hence the statement above may not necessarily speed up applications, though it's worth considering.
- BC Hydro considers that 100kW increase will not affect PV participation since PV system capacity is most often than not limited by residential roof-top area

Capacity Reasoning:
50kW:
Residential customers would not require 100 kW generators to displace their electricity load; 50 kW is more than enough, and is consistent with max amperage and voltage for residential customers. 50kW would not result in costly interconnection costs, and volume of energy coming onto grid could be managed. Most importantly; size limit is intended to reduce potential cost-shifting (cross subsidization) to non-NM customers.
100kW:
BCUC considers that RS 1289 need be driven not by maximum theoretical residential load, but by economically available clean energy. BCUC, given the legislative/regulatory emphasis on NM/clean energy, opined that lowering participation barriers was of most importance. 100kW gens are appropriate for General Service customers, whereas 50kW is limiting. Capped at 100kW since large generators tend to incur higher interconnected-related costs, and affect simplicity of program implementation.
No need to go over 100kW given:
- >70% of RS1289 customers use gens of <5kW
- >90% of RS1289 customers use gens of <25kW

Other Information
Meter:
Single meter capable of measuring flows of electricity in both directions. If meter is unreliable, BC Hydro may require two meters
Standard Offer Program
The SOP is meant for clean energy generators 50kW-15MW that intend to sell electricity to BC Hydro. Base price varies from 9.5 to 10.4c/kWh (before annual CPI escalation).
A proposed micro-SOP program would look after generators in the range 50kW-1MW who want to sell electricity to BC Hydro.
The intent is that there by cross-over between micro-SOP and RS 1289 to give customers room to decide which program is best for them.

NM Experience

(March 2013)
- 228 sites (206 PV)
- 1.138 MW (78% PV, 15% hydro, 2.5% wind, 2.5% wind/PV and 2% biogas)

See Net Metering Evaluation Report No.3

Sources

General:
http://www.bchydro.com/energy-in-bc/acquiring_power/current_offerings/net_metering.html

Eligibility Requirements:
http://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/independent-power-producers-calls-for-power/net-metering/schedule-1289-net-metering-service.pdf

Net Metering Evaluation Report No. 3 - BC Hydro:
https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/independent-power-producers-calls-for-power/net-metering/net-metering-evaluation-report-april2013.pdf

Application:
http://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/independent-power-producers-calls-for-power/net-metering/simple-net-metering-application-form.pdf

BCUC Final Decision:
http://www.bcuc.com/Documents/Proceedings/2014/DOC_41819_G-104-14_BCH_RS1289-Net-Metering_Decision.pdf

[1] BC Hydro Reply Submission
http://www.bcuc.com/Documents/Arguments/2014/DOC_41350_05-14-2014-BCH-ReplySubmission.pdf

[2] BC Hydro, Responses to BCUC
http://www.bcuc.com/Documents/Proceedings/2014/DOC_41257_B-4_BCH-Responses-to-BCUC-IR1.pdf

NAVIGANT

NM Jurisdictional Review

Jurisdiction

Manitoba

Customer Owned Generation

Drivers for NM

Driving force:
Manitoba Hydro (MH) offers the Customer Owned Generation program.
The driving force for this program is unknown

Market:
Manitoba Hydro (MBH), fully integrated, regulated by the Public Utilities Board (PUB).

MB's Clean Energy Strategy Plan (2012) states that MB's priorities are the construction of the Keeyask (695MW) and Conawapa (1,485MW) hydroelectric plants given the need for new capacity for 2023.

Generation Capacity:

Dec 2012	MW	%
Diesel	10	0%
Natural Gas	353	6%
Coal	105	2%
Hydro	5,217	88%
Renewable	252	4%
Total	5,927	100%

Program Design/Framework

Legislative Considerations:
Manitoba Hydro Act

- Section 38 (1), Purchase of Power: *"The price to be paid by the corporation for power supplied to it…..shall be computed by the board at the amount of the actual costs of producing it"*
  - This sets a framework where any cash payout will be determined by an avoided-cost approach
- Section 15 (4), Transmission access: *"The corporation may enter into agreements…under which the corporation may provide access to the transmission facilities of the corporation to any person…for sale"*

There is no relevant legislation or regulation regarding Customer owned generation

Eligibility Requirements

- Any customer
- Renewable energy (solar, wind, hydro, organic matter)
- Non-renewable energy (e.g. fossil fuels)
- Single Phase: 50 kW
- Three Phase: 10 MW
- Meter aggregation: no mention of aggregation, project location, etc.
- Subscription limit: Not included

Types of Customer Owned Generation
MBH has 5 types of Distribution Resource interconnections. The two most relevant, known as Parallel Generation, for NM are:

- Type II - Load displacement only (no export)
- Type III - Load displacement plus excess to grid: Similar to Type II except that power is allowed to flow back to the utility.

Implementation (Application Process):
All generators must meet technical requirements in DR Interconnection Guideline
For <10kW:

- CSA-certified, electrical inspection
- Registered with MBH using the "DR Interconnections 10 kW or Less Registration Form"

For >10kW, undergo a 5 Stage Process (case by case):

- Stage 1 – Exploratory, initial meeting with MBH
- Stage 2 – Scoping & Preliminary Estimates
- (incl. single line diagram, generation information, generation profile)
- Stage 3 – Interconnection Study, composed of (a) engineering study, and (2) energy purchase price
- Stage 4 – Agreements (PPA, and Interconnection and Operating Agreement)
- Stage 5 – Construction & Commissioning

Customer & Program Costs/Benefits

Bill Determination/Rate Structure

- Based upon PPA in Stage 4, a customer may be entitled to sell excess kWh-s to MBH.
- Energy Purchase Price:
  - Preliminary estimate determined in Stage 2 of interconnection process
  - Final estimate in Stage 3: Energy Purchase Price (actual) is based on the cost of integrating the generator's output into the system (e.g. environmental premiums; government subsidies, integration into peak hours; M-F, 6am-10pm)
- There is no mention of kWh credits, carry-over, or cash-payouts and anniversary dates.
- It is understood that the T&C of the PPA will determine the bill determination/rate structure. Type II customers would not be entitled to energy payments, only Type III

Responsibility for associated net metering costs
Customer Costs:

- Bi-directional revenue meter
- Cost of the interconnection protection equipment, and all additional interconnection upgrades, equipment required
- Construction costs (if any) will be determined in Stage 2 of interconnection process
- Engineering study (Type II: $500, Type III: $1,000 deposit prior to determining actual cost)
- Metering

Utility Costs:

- Program administration costs

Regulatory Treatment

Cross Subsidization Issues:

- Level of cross-subsidization is only limited to program administration costs

Analysis:
MH Development Plan and NFAT (Need for Alternatives to), Appendix 7.1 Emerging Energy Technology Review [November 2013]:
MBH was asked to evaluate the c/kWh price for a 1,300kWh/kW, 4kW PV system for 6%ROI over 20years, and compare it with the current residential rate

- The 2013$ LCOE was determined to be 10.55c/kWh, compared to the residential rate of 7.138c/kWh
- MH recognized that it *"[does] not have an appropriate net metering pricing mechanism to cover solar integrations costs (costs of dealing with the intermittency)"*

Other information
Meter:
Type II: regular one way
Type III: bi-directional

Bioenergy Optimization Program
This program is part of MBH's Power Smart Plan (2008-present) which encourages customer self-generation using biomass systems. The program targets large (general service class) agricultural and industrial customers with low-cost sources of biomass that are Load Displacement (Type II and III) customers. MBH provides incentives and financial support. The (cumulative) expected capacity savings up to 2013/14 was 1.4MW (12GWh).

NM Experience

N/A

Sources

General:
http://www.hydro.mb.ca/customer_services/customer_owned_generation/index.shtml?WT.mc_id=2704

Application:
http://www.hydro.mb.ca/customer_services/customer_owned_generation/distributed_resource_interconnection_request.pdf

Technical Requirements:
http://www.hydro.mb.ca/customer_services/customer_owned_generation/connecting_distributed_resources.pdf

Procedures:
http://www.hydro.mb.ca/customer_services/customer_owned_generation/distributed_resource_interconnection_procedures.pdf

Need For Alternative To (NFAT) - Report:
http://www.hydro.mb.ca/projects/development_plan/bc_documents/new/round_1_supplemental_response_november_22.pdf

Bioenergy Optimization Program
http://www.pub.gov.mb.ca/nfat/pdf/hydro_application/appendix_e_2013_16_power_smart_plan.pdf

Clean Energy Strategy:
http://www.gov.mb.ca/ia/energy/pdfs/energy_strategy_2012.pdf

NAVIGANT

NM Jurisdictional Review

Jurisdiction

New Brunswick

Net Metering

Drivers for NM

Driving force:

In 2001, the NB Government appointed a Market Design Committee (MDC) to advice on electricity policy that the NM & Energy had outlined in its Energy Policy white paper.

The MDC recommended a few initiatives; NM, embedded generation, RPS, Energy Efficiency, CO2 emissions trading.

In 2005, NB Power introduced the NM and Embedded Generation programs

Market:

NB Power, single vertically integrated crown utility. NB power is regulated by the Energy & Utilities Board (EUB)

Generation Capacity:

Dec 2012	MW	%
Diesel	1,497	35%
Natural Gas	351	8%
Coal	467	11%
Nuclear	638	15%
Hydro	939	22%
Renewable	332	8%
Total	4,223	100%

NB's 2011 Energy Action Plan, Immediate Priority includes:

- *"Encouraging public awareness and adoption of net metering and embedded generation"*

NB Climate Change Action Plan 2014-2020:

- NB Power and Gov. will review NM & embedded generation to ensure it continues to meet goals, keeps rates low.

Program Design/Framework

Legislative Considerations:

Electricity Act:

Note: the 2013 Electricity Act required the reintegration of NB Power

- 103(7): *"In approving or fixing just and reasonable rates, the Board….taking into consideration….any requirements imposed by law on the [NB Power] that may be relevant to the application, including….renewable energy requirements"*
- The minister can be responsible for *"setting the purchase price...for electricity obtained from renewable resources"* (i.e. Large Industrial Renewable Energy Purchase program)
- 136(1): *"The Corporation shall, in accordance with the regulations, ensure that a portion of the electricity that it obtains is from renewable resources"*
    - o As outlined in the 2011 Energy Blueprint, this portion is a 40%RPS by 2020

Eligibility Requirements

- 100 kW
- Meter aggregation : no meter aggregation allowed, exception apply for farmers
- Subscription limit:
    - o In 2008, the aggregate capacity of the Net Metering and Embedded Generation programs was capped at 21MW
    - o Evaluation: Nov 2010: *"The current net metering program has a peak demand capacity limitation of 0.5% of NSPI's historical annual capacity (approximately 12 MW), with only approximately 600 kW of that amount currently subscribed."*

Implementation (Application Process):

- Net Metering (Distribution Voltage) Interconnection Application
- Single-line diagram and site location drawing
- Inverter's technical specifications
- A licensed electrician will need to provide NB Power with an electrical wiring permit
- Approval by the NB Dept. of Public Safety, Technical Inspection Services

Customer & Program Costs/Benefits

Bill Determination/Rate Structure

- Excess electricity carried over as a credit
- Credits are carried up to March 31 of each year.
- After March 31, credits are reduced to zero.

Responsibility for associated net metering costs

Customer Costs:

- Service call fee for changing to a bi-directional meter;
- Connection fees
- Costs to purchase and install equipment;
- Monthly service charge
- Rental charges if applicable
- HST on the total amount of electricity delivered, not the net amount of electricity billed
- A meter connected-telephone line

Utility Costs:

- Program administration fees, metering, meter

Regulatory Treatment

Cross Subsidization Issues:

NB Market Design Committee (MDC)'s 2002 final report:

- MDC members raised concerns with the potential for cross-subsidization; hence the MDC recommended that NM system capacity be set at 100kW, and cumulative capacity should be 1% of utility's max demand.

Other information

Embedded Generation Program

- Connect environmentally sustainable generation unit to the 12kV distribution system
- 100kW-3MW (exact capacity size limit to be determined in application process)
- Generator's energy output not used to offset customer's electricity consumption, but rather purchased as in a FIT program (as of June 1 2010, 9.728c/kWh)

Large Industrial Renewable Energy Purchase

- NB Power purchases (at $95/MWh) renewable energy generated from large industrial facilities. The purpose is to reduce the overall electricity costs of such facilities to be in line with the Canadian average.
- Aggregation is valid, so as long as facilities are owned by larger enterprise
- Purchased renewable energy will contribute to the NB's RPS (40% by 2020)
- For F2013, F2014, 779GWh was purchased.

NM Experience

N/A

Sources

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Technical Specification for Net Metered Generation:
http://www.nbpower.com/html/en/save_energy/renewable_projects/net_metering/Technical%20Specification%20for%20Net%20Metering%20APR%2010%20EN.pdf

Application:
http://www.nbpower.com/html/en/save_energy/renewable_projects/net_metering/Application%20Net%20Metering%20%20EN%20Revised%202009.pdf

MDC Report (2002)
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Energy Blueprint (RPS):
http://www2.gnb.ca/content/dam/gnb/Departments/en/pdf/Publications/201110NBEnergyBlueprint.pdf

Laree Industrial Renewable Energy Purchase:
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Energy Action Plan:
http://www2.gnb.ca/content/dam/gnb/Departments/en/pdf/Publications/201110NBEnergyBlueprint.pdf

NAVIGANT

NM Jurisdictional Review

Jurisdiction

Nova Scotia

NSPI - Enhanced Net Metering

Drivers for NM

Driving force:
Nova Scotia Power Inc. (NSPI has offered NM since 1989. The Utility and Review Board (UARB) officially approved it as *NSPI Regulation 3.6* in 2006. Further, with the Ministry of Energy's 2010 Renewable Electricity Plan; it established targets for (1) its large renewable procurement program, (2) COMFIT program, and (3) it also proposed enhancing the NM program. The current structure of the NSPI Regulation 3.6 follows the 2010 Electricity Act amendment.

Market:
NS Power (NSPI), near monopoly, 6 munis, IPPs. Regulated by the UARB.

Generation Capacity:

Dec 2012	MW	%
Diesel	222	8%
Natural Gas	321	12%
Coal	1,243	47%
Hydro	400	15%
Renewable	453	17%
Total	2,640	100%

Program Design/Framework

Legislative Considerations:
Electricity Act:

- 3A(1): *"A public utility may develop and maintain a program that will permit any customer to generate electricity for the customer's own use and to sell any excess electricity to the public utility at a rate equivalent to the rate paid by the customer for electricity supplied to the customer by the public utility"*
- Under 3A, the electricity act sets the framework for the NM program

(Electricity Act) Renewable Electricity Regulations:

- *"Each year beginning with the calendar year 2020….each load-serving utility must supply greater than 40% of the total amount of electricity supplied"*
- *"Beginning with…2014…NSPI must produce or acquire at least 350GWh of firm renewable electricity each year"*

Eligibility Requirements

- All NS Power customers who are served from NS Power's Distribution system and who are billed under NS Power's metered service rates
  - Class 1: Residential and commercial (<100kW)
  - Class 2: Larger commercial or industrial customers (1MW)
- Solar, Wind, run-of-the-river, ocean, tidal, wave, biomass, landfill gas (as defined in the Renewable Electricity Regulations under Section 5 of the Electricity Act)
- Two class proposal intended to reflect the current break point for generation interconnection standards (projects >100kW are subject to more complex assessments/interconnection process)
- Meter aggregation : Credits may be used for multiple accounts within the same distribution zone (Definition: "All NS Power distribution feeders that emanate from a single distribution supply transformer within a substation")
- Generators must be sized to meet a customer's electricity consumption (NSPI to evaluate).

Implementation (Application Process):
Class 1:

- Expedited process for <10kW (submit interconnection form, manufacturer information, single line diagram)
- 11kW-100kW (interconnection form, manufacturer information, single line diagram, site plan, protective device data, point-of-contact info.)

Class 2:

- 101-1,000kW (distribution interconnection form, preliminary assessment, class 2 form, distribution impact study)

Customer & Program Costs/Benefits

Bill Determination/Rate Structure

- Customers billed for the difference at their regular retail rate (applicable also for TOU customers)
- Any monthly surplus carried over to the next monthly bill as credits
- End of year: Customers are provided a cash payout at the retail rate

Responsibility for associated net metering costs
Customer Costs:

- Monthly base charge
- All costs incurred by NSPI to deliver the NM service relative to regular customers.
- Incremental costs to install a bi-directional meter

Utility Costs:

- Program administration, metering, meter

Regulatory Treatment

Cross Subsidization Issues:
UARB Ruling, Regulation 3.6:

- Halifax Regional Water Council (HRWC) challenged the 20MW limit, proposing get rid of the limit. NSPI replied: *"The uptake of the net metering service will lead to a reduction in NSPI's kWh sales without a parallel reduction in the total amount of non-fuel related costs (that is, fixed costs) to be recovered by the utility"*
- NSPI went on to say that this will result; first, in under-recovery of fixed costs, and second, in an increase rate charge to all customers. NSPI noted that once they gain an understanding and experience with the enhanced program the 20MW limit will be revisited if needed.

Electricity Act (NSPI Regulation 3.6):
(March 2011)
"as a condition of participation, the customer transfer or assign all ***emission credits*** *or allowances arising from the use of renewable energy sources to the public utility to enable the public utility to comply with the requirements of any enactment regulating emissions"*

- This amendment follows from the Board's Decision 2009 NSUARB 116: "The Board orders that all environmental credits created by projects funded by DSM investments are to stay with the DSM Administrator for the benefit of all customers"

UARB Ruling, Regulation 3.6:
NSPI argued for the following capacity limits: 5MW allocated to Class 1, and 15MW allocated to Class 2; for a total capacity limit of 20MW.

- In the regulatory process; Halifax Water argued that the 5, 15, and 20MW limits were set arbitrarily. NSPI countered citing an almost 100% increase (from 12MW capacity), and that *"allocating 20MW to this enhanced program will allow NSPI to monitor and evaluate the program's cost recovery implications for the utility and its customers"*.
- The UARB ruled to not include any capacity limit (5, 15 nor 20 MW) because (1) the Electricity Act made no reference to capacity limits, and only encouraged increasing levels of renewable energy, and (2) NSPI provided no evidence for those limits.

Finally, the UARB requested that NSPI submit an annual Enhance NM progress report.

Other information
Community Feed-In Tariff (COMFIT)
Allows small scale producers to bypass renewables procurement program (for large capacities). Intended for community-based, local projects.

NM Experience

(Jan 1, 2014):
157 sites with 1,152.4kW

- Solar: 78 sites, 364.7kW
- Wind: 78 sites, 779.0kW
- Solar/Wind: 1 sites, 8.8kW

Sources

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Act:
http://nslegislature.ca/legc/statutes/elctrcty.htm

Regulations:
http://www.gov.ns.ca/just/regulations/regs/elecrenew.htm

NSPI Regulation 3.6:
https://www.nspower.ca/site/media/Parent/Regulation.3.6.Net.Metering.pdf

Guidelines
https://www.nspower.ca/site/media/Parent/Interconnection.Technical%20Guideline-Net.Metering.pdf

Application and process flowcharts:
http://www.nspower.ca/en/home/environment/renewableenergy/enhanced/apply/default.aspx

Regulation 3.6 UARB Ruling:
http://nsuarb.novascotia.ca/sites/default/files/documents/electricityarchive/netmetering.pdf

2/23/2011, NSPI Reply Submission:
http://uarb.novascotia.ca/fmi/iwp/cgi?-db=UARBv12&-loadframes

NAVIGANT

NM Jurisdictional Review

Jurisdiction

Ontario

Net Metering

Drivers for NM

Driving force:
The Ontario government passed the Ontario Regulation 541/05 under the Ontario Energy Board Act in 2005, and effective January 23, 2006. Then in 2009, the Green Energy Act (GEA) introduced the FIT program.

Market:
Deregulated, multiple generators, Hydro-One owns transmission system, 75+ LDCs, all are regulated by Ontario Energy Board (OEB)

Net metering has been specified as a policy objective in the 2013 Long Term Energy Plan (LTEP): *"Ontario will examine the potential for the microFIT program to evolve from a generation purchasing program to a net metering program"*

Given this emphasis -under the current rate design- increases in NM would decrease LDCs' revenue as NM consumers reduce their electricity use.

Generation Capacity:

Dec 2012	MW	%
Natural Gas	7,180	23%
Nuclear	12,856	41%
Hydro	8,445	27%
Renewable	2,352	8%
Total	31,222	100%

Program Design/Framework

Legislative Considerations:
Ontario Regulation 541/05 made under the Ontario Energy Board Act, 1998

Green Energy Act (GEA):
- Preamble: *"The Government of Ontario is committed to fostering the growth of renewable energy projects, which use cleaner sources of energy, and to removing barriers to and promoting opportunities for renewable energy projects and to promoting a green economy"*
- *"The Minister may direct the OPA to develop a feed-in tariff program that is designed to procure energy from renewable energy sources"*

Eligibility Requirements
- 500 kW (must produce electricity primarily for own use)
- Eligibility: no reference to residential/general service
- Renewable energy source
- Meter aggregation: No
- Subscription limit: 1% (last update was in March 2006)
- Generators must be sized to meet a customer's electricity consumption

Implementation (Application Process):
<10kW (Micro-embedded Generation)
- Micro-Generation Connection Application Form
- meeting Technical Interconnection Requirements (TIR)

>10kW (Small, Mid-sized & Large Embedded Generators)
- Connection Impact Assessment (CIA) form
- Study Agreement
- Distribution Operating Map (DOM) Request (from Hydro One)
- Single Line Diagram, and TIR

Customer & Program Costs/Benefits

Bill Determination/Rate Structure
- Credits for excess electricity are carried over
- Credits can be carried over up to 12 months
- Any unused credits remaining at the end of 12 consecutive months **cleared**

Responsibility for associated net metering costs
Customer Costs
- Distributor may bill a customer for incremental metering and other costs incurred in order to connect the eligible generator's generation facilities to its distribution system
- Customer pays for charges that are not calculated on the basis of the customer's consumption of or demand for electricity (i.e. admin, demand charges, T&D fees)

Utility Costs:
- Program administration, metering, meter

Regulatory Treatment

Evaluations
Distribution System Code:
An LDC must make NM available upon request, *"unless the cumulative generation capacity from net metered generators…equals [1%] of the distributor's annual maximum peak load"* averaged over three years. It was set at 1% having the OEB recognize the revenue impacts of a large uptake of NM and to limit their exposure to revenue decreases.
Since the last revision (March 2006), the total provincial capacity limit is 260MW (which is approximately ¾ of 1% of the current provincial capacity, 35GW)
LDC's are required to submit NM participation rates (and capacity, and project type) annually to the OEB

In its Notice of Proposal to Amend a Code; the OEB states that *"It is not anticipated that electricity distributors will incur substantial costs as a result of the proposed amendments."*
- Hydro One commented that they would be implementing a manual solution to settlement costs, which would entail costs of $75K CAPEX, and $50K OPEX, though noting that a manual solution would not be sustainable given large NM customers. An automated system could costs $1M.
- ENWIN Powerlines argued that an LDC's customer base with a large base of industrial customer would have an inflated NM capacity limit (1% as noted above), given that NM is intended at encouraging residential and small-commercial customers.

NM Experience

(Oct 2014):
- 167.3MW (99% solar)
- 19,275 projects

This data is representative of only Ontario's microFIT program (for <10kW), and accumulates projects from microFIT 1.3-1.6, 2.0 and 3.0

See OPA Micro-FIT Weekly Report (Oct 3, 2014)

Sources

Green Energy Act:
http://www.e-laws.gov.on.ca/html/source/statutes/english/2009/elaws_src_s09012_e.htm

Net Metering (Hydro One)
http://www.hydroone.com/Generators/Pages/NetMetering.aspx

Regulation:
http://www.e-laws.gov.on.ca/html/source/regs/english/2005/elaws_src_regs_r05541_e.htm

Distribution System Code
http://www.ontarioenergyboard.ca/OEB/_Documents/Regulatory/Distribution_System_Code.pdf

OEB, Distribution System Code:
http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/Archived+OEB+Key+Initiatives/Proposed+Amendments+to+Distribution+System+Code

Proposed Amendments to the Distribution System Code (see for Hydro One and ENWIN comments):
http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/Archived+OEB+Key+Initiatives/Proposed+Amendments+to+Distribution+System+Code

OEB – Notice of Proposal to Amend a Code:
http://www.ontarioenergyboard.ca/documents/cases/EB-2005-0447/noticeamendacode_051205.pdf

LTEP:
http://powerauthority.on.ca/sites/default/files/planning/LTEP_2013_English_WEB.pdf

OPA Micro-FIT Weekly Report (Oct 3, 2014):
http://microfit.powerauthority.on.ca/sites/default/files/bi-weekly_reports/mFIT%20Report%20Bi-Weekly%20October_3_2014.pdf

NAVIGANT

NM Jurisdictional Review

Jurisdiction

Prince Edward Island

Maritime Electric - Net Metering

Drivers for NM

Driving force:
The Renewable Energy Act, came into effect in 2005, introduced the Net Metering program

Market:
Maritime Electric (MECL) regulated by Island Regulatory & Appeals Commission (IRAC), Summerside Electric (muni), not as closely regulated by IRAC.
Government's intent in introducing NM is to assist customers who want to supply a portion, or all, of their annual electricity load from their own small capacity renewable energy generator.
There seems to have been a shift in focus -as outlined in PEI Energy Commission's reports- towards community-based wind projects.

Generation Capacity:

Dec 2012	MW	%
Diesel	161	39%
Renewable	247	61%
Total	408	100%

Reliance on NB Power has been in the range of 80-90% for electricity generation. MCEL relies primarily on two 100MW cables from NB Power.
MECL is looking at options to build a 3rd -180MW- cable to be in-service by 2016

Program Design/Framework

Legislative Considerations:
Renewable Energy Act (came into effect 2005) includes:

- RPS of 15% by 2010
- Minimum purchase price of 7.75c/kWh for renewables (applicable to Wind until 15%RPS achieved, but will remain in effect for other renewables), fixed 5.75c/kWh and 2c/kWh subject to CPI.
- REJECTED (not passed into law): 100% renewable by 2015

Eligibility Requirements

- 100 kW
- Eligibility: MECL customers who are served from the distribution system and are billed under one of the metered service rates (unmetered not eligible)
- Meter aggregation: No
- Subscription limit: No

Implementation (Application Process):
Single Process for all applicants:

- Two copies of the prescribed net-metering system agreement that
- Drawings or information concerning the interconnection equipment or renewable energy generation facility

Customer & Program Costs/Benefits

Bill Determination/Rate Structure

- Billed for net usage during the month
- Excess kWh are credited
- Credits don't accumulate indefinitely (on Oct 31of each year, or as set out in agreement, credits expire)

Note: Prior to *Renewable Energy Act* the customer was paid based on avoided generation costs, which was usually taken as the wholesale price. The difference was recovered from all customers

- Monthly service charge always included

Responsibility for associated net metering costs
Customer Costs:

- Permits and licenses required for the construction and operation of generation unit
- Upgrade cost to utility's its electric system
- Incremental costs relative to regular customers
- Liability insurance

Utility Cost:

- Covers costs associated with customer having two meters (The Renewable Energy Act provides for the costs that the utility incurs in complying with the provisions of the Act to be passed on to all customers through rates.)

Regulatory Treatment

Other information
PEI Energy Strategy, Securing Our Future (2008)
Government actions:

- Govt. will double its RPS to 30% by 2013
  - By 2013, achieved 43%.
- Govt. will maximize the benefits of future large-scale wind developments (historically, primary focus has been on large scale wind generation)
- Govt. to evaluate and develop appropriate policy mechanisms, such as net-billing and the allocation of electrical capacity, to facilitate the development of smaller community-based wind and other renewable energy projects

Island Wind Energy, Securing Our Future: The 10 Point Plan (2008)
Goal:

- 500MW of Wind by 2013
  - (3 point) "Demonstrating Community Support; engaging the community in discussion and secure support for their proposal, local communities must share in the benefits from wind energy, and proceeds from wind farms will be invested in a Community Trust Fund"

Charting our Electricity Future (2012)
The PEI Energy Commission received input calling for a strong commitment by the province toward **community-based renewable energy development** (especially Wind energy), and recommended the use of DR policies such as NM. The commission highlighted the Wind Energy Institute of Canada's NM Initiative. The Institute evaluated 17 proposals from ice rinks across Prince Edward Island. Four rinks qualified for the program, w/ funding up to $180K (72% of project costs). 50kW turbines were installed

Renewable Energy Equipment Tax Exemption
On April 2013, PEI adopted the HST, replacing the PST. Prior, renewable energy systems (incl. wind, solar PV/thermal, biogas <100kW) were exempted from the PST.

NM Experience

NM ():
200kW

Data reported from four community based projects that installed 50kW turbines, sponsored by WEICAN

See WEICAN-Annual Operational Update Fall 2012

Sources

General:
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Renewable Energy Act:
http://www.canlii.org/en/pe/laws/stat/rspei-1988-c-r-12.1/latest/part-1/rspei-1988-c-r-12.1-part-1.pd

Regulations:
http://www.irac.pe.ca/document.aspx?file=legislation/RenewableEnergyActNet-MeteringSystemsRegulations.asp

Net Metering Brochure:
http://www.maritimeelectric.com/documents/environment/Net_Metering_Brochure.pdf

PEI Energy Strategy: Securing our Future
http://www.gov.pe.ca/photos/original/env_snergystr.pdf

Island Wind Energy: 10 Point Plan
http://www.gov.pe.ca/photos/original/wind_energy.pdf

Changing our Electricity Future
http://www.gov.pe.ca/photos/original/NRGCommish_13.pdf

2014 Statistics
http://www.gov.pe.ca/photos/original/pt_annualreview.pdf

WEICAN – Annual Operational Update Fall 2012:
http://www.weican.ca/documents/WEICan_Operational2012_ENG.pdf
NET METERING INITIATIVE – WIND TURBINE SELECTION
http://www.weican.ca/news/2009/Net_Metering_-_Arena_Information_Turbine_suppliers_v6.pdf

NAVIGANT

NM Jurisdictional Review

Jurisdiction	Drivers for NM	Program Design/Framework	Customer & Program Costs/Benefits	Regulatory Treatment	NM Experience	Sources
Quebec *Hydro-Québec - Metering Rate Option*	**Driving force:** The Regie de l'energie (The Regie), the energy regulator in Quebec, passed a NM regulation (3535-04) on June 2004. The Regie's intent was designed to help customers meet all or part of their energy needs, not to sell their surplus power to the Distributor. **Generation Capacity:** (see table below)	**Eligibility Requirements** • 50 kW • Renewable energy sources including: wind, solar, hydro, geothermal, bioenergy • Residential customers, farmers billed at Rate D or DM (without billed power demand*) and small-power business customers billed at Rate G (without billing power demand*) - *Less than 50 kW. • Generating capacity must not exceed the estimated capacity required to meet all or part of power needs *Quick estimate:* Eligible kW ≤ Annual Consumption (kWh)/(8,760 hours x 35%) • Meter aggregation: No • Subscription limit: No Implementation (Application Process): Application process: • Enrollment Form with a description of the equipment you plan to buy and return it to Hydro-Québec for technical validation • Sign the Interconnection Agreement and mail it to Hydro-Québec • purchase your generating equipment and have it installed • Hydro-Québec will then inspect your facility, for a charge of $400, to make sure it complies with the terms of the Interconnection Agreement; install a dual-register meter, at no expense to you.	**Bill Determination/Rate Structure** • Surplus kWh are carried over as credits • Accumulated credits must be used within 24 months (customer can inform utility of the chosen expiry date; otherwise the default date of March 31 will apply) • March 31; any credits are lost. **Responsibility for associated net metering costs** Customer Costs: • purchasing, installing, maintaining and inspecting the equipment • pay utility $400 to inspect the unit Utility Costs: • install a dual-register meter, program administration costs, metering	**Other information** Hydro-Québec does not provide any rebates to homeowners for the installation of onsite renewable customer owned generation sources. Self-generation without compensation plan If project is not renewable, HQ does not provide kWh credits for surplus generation	N/A	Hydro Quebec, Net Metering: http://www.hydroquebec.com/residential/understanding-your-bill/rates/residential-rates/net-metering-option/ Net Metering Brochure: http://www.hydroquebec.com/self-generation/docs/depliant-mesurage-net.pdf Net Metering Enrollment Application: http://www.hydroquebec.com/self-generation/docs/guide-mesurage-net.pdf The Regie, Acts and Regulations: http://www.regie-energie.qc.ca/en/regie/reglements.html

Dec 2012	MW	%
Diesel	625	2%
Natural Gas	1,463	4%
Hydro	37,137	90%
Biomass	1,477	4%
Total	41,336	**100%**

NAVIGANT

NM Jurisdictional Review

Jurisdiction

Saskatchewan

SaskPower - Net Metering

Drivers for NM

Driving force:
The SK Ministry of Environment launched net metering in 2007, as part of its Green Power Portfolio. SaskPower developed the NM policy

Generation Capacity:

Dec 2012	MW	%
Natural Gas	1,337	33%
Coal	1,682	41%
Hydro	853	21%
Wind	198	5%
Total	4,089	100%

Program Design/Framework

Eligibility Requirements
- 100 kW
- Biogas and biomass; flare gas; heat recovery; low-impact hydro; solar; turbo expander; wind
- Available to all metered, non-seasonal customers
- Meter aggregation: No
- Subscription limit: No

Implementation (Application Process):
- Complete: "Application for Net Metering and Preliminary Interconnection Study" form
- SaskPower will provide a quote of the total costs (connection, commissioning, new meter), and the "Interconnection Agreement for Net Metering".
- Application for rebate program
- System installation, commissioning
- Electric permit and inspection

Customer & Program Costs/Benefits

Bill Determination/Rate Structure
- Excess electricity is carried over as credits
- Excess electricity should be used within 12 months, otherwise on the anniversary date, any credits will **reset to zero**
- To maximize credits built up in a 12-month period, SaskPower sets the anniversary date based on the type of generation system (however the date can be adjusted by customer)
  - Solar PV – March/April: maximizes credit build up over summer
  - Wind: Aug/Sept: maximizes credit build up over winter/spring
  - Others: anniversary reflects month when meter installed

Responsibility for associated net metering costs
Customer Costs
- Responsible for all interconnection costs
- preliminary interconnection study ($315 including GST)
- bi-directional meter and interconnection cost ($475 plus GST)
- electrical permit fee
- installation, commission and electrical inspection of the system

Government Rebate Program:
- One-time rebate, equivalent to 20 per cent of eligible costs to a maximum payment of $20,000, for an approved and grid interconnected NM project (up to November 30, 2014), launched in 2013.
- Prior, the SK Ministry of Environment (through the Go Green Fund) introduced a NM Rebate in 2007, which provided up to $35,000 to program customers. The program was to expire in March 2011, but was extended and given a funding boost due to an 'unexpected influx of applications' received, and lobbying form the Saskatchewan Chamber of Commerce
- The Ministry's rebate program was designed as a demonstration project to assess the feasibility of promoting the adoption of small scale solar technologies

Regulatory Treatment

NM Evaluations & Other Information
Net Metering Program
- SaskPower owns all environmental and GHG offset credits.
- No program subscription limit

Evaluation:
As per regulation, the Net Metering Program is reviewed annually, though these reports have not been made available publicly.

SaskPower Presentation: Net Metering and Small Power Producers (as of 2010) :
- For 2017, SaskPower projects 8MW of NM projects
- Solar projects ranged from 1-9kW, and wind projects ranged from 1-40kW. No projects were close to the 100kW limit.
- The average processing time went from 10months (2007) to 5months (2010).
- A plan was developed to allow for a cash payout for remaining credits after 12months, though never came to life.
- A plan for a simpler application process for <20kW, with standard pricing, contract, installation

CanSIA Evaluation:
Recommends a transition to incentivize power system performance. NM customers would be encouraged to purchase subpar equipment (compared to better performing equipment) in order to benefit from the equivalent rebate. A future program should be incented to pursue optimum performance systems; such as to maximize ROI (from the province's and NM customer's point of view).

Executive Summary on the Go Green Fund Program (which includes the NM rebate)
- *"the net metering program was a great catalyst for growth of the solar industry in Saskatchewan"*
- As of F12Q1, 316 projects received rebates

Inquiry into Saskatchewan's Energy Needs Final Report (April 5, 2010)
The Committee made series of recommendations:
- Recommendation 8: *"….that SaskPower evaluate its net metering program and determine its potential expansion"*
- Recommendation 9: *"….that SaskPower examine net metering options for customers who have more than one meter on an account"*
- Recommendation 8: *"….that SaskPower explore better avenues to promote the net metering program and small power producers program"* (see below for program)

These recommendations were raised due to a series of public concerns including that SaskPower had done a poor job in informing customers about the program and that Ontario's FIT program was something to strive to. SaskPower's cautioned against very large incentive programs like Ontario's.

Small Power Producers Program
For customers w/ <100kW, who will sell the excess or all electricity to SaskPower; under certain contract rules:
- 9.8c/kWh (2012), escalating at 2%/yr.
- Electricity banking (NM) not allowed
- 20yr contract (40 for hydro)
- No program capacity
- Environmental credits owned by SaskPower
- In 2010, program reached 320kW in cumulative capacity (projection to 2017 is 2MW)

NM Experience

NM (2014):
- 400 sites (expected 100 new/yr.)
- 5.1MW (estimate based on 1.3MW in 2010, and 8MW estimate to 2017)

Note:
In 2010:
- 1.3MW (target was 1.1MW)
- PV: 154kW
- Wind: 1,143kW
- 184 projects

See SaskPower Presentation

Sources

General:
http://www.saskpower.com/efficiency-programs-and-tips/generate-your-own-power/self-generation-programs/net-metering-program/

SK Power NM Policy:
http://www.saskpower.com/wp-content/uploads/net_metering_policy.pdf
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Application:
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Go Green Fund Program Review:
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SaskPower:
Net Metering and Small Power Producers
http://www.cansia.ca/sites/default/files/policy_and_research/20110704_cansia_submission_solar_power_in_saskatchewan.pdf

SaskPower Presentation:
http://www.organicconnections.ca/archives/conference2010/docs/OC%20pdf%20presentations2/Loughran.pdf

NAVIGANT

NM Jurisdictional Review

Jurisdiction

Yukon

Micro-Generation Policy and Micro-Generation Production Incentive Program

(This program is the 'net metering' portion of the Micro-Generation Policy)

Drivers for NM

Driving force
In the Government's Energy Strategy for Yukon (2009), it set out to develop a NM policy. After a period of public consultation, the Government released the final version of Micro-Generation policy in October 2013, and policy implementation began in Feb 2014.

Policy objectives:

- adoption of new individual renewable energy sources to reduce GHGs diversify renewable energy sources

Market:
Yukon Energy Corp (YEC, a public utility) generates most of the electricity, and distributes to a small portion of communities outside Whitehorse. Yukon Electrical Company (YECL), an IOU, distributes to Whitehorse and most other communities. Both utilities are regulated by the Yukon Utilities Board

Generation Capacity:

Dec 2012	MW	%
Diesel	55	37%
Hydro	94	62%
Wind	0.8	1%
Total	150	100%

YEC generates 98% of electricity from hydro.

Program Design/Framework

Legislative Considerations
YEC required to serve areas of the territory not served by an IOU

Eligibility:

- Customers on a shared transformer = 5 kW
- Customers on a single transformer = 25 kW
- Projects up to 50kW will be review on a case-by-case basis (review costs are on the customer)
- Residential, general service and industrial customers
- Renewable technology including: wind, micro-hydro, biomass, solar

Meter aggregation: No
Subscription limit: No limit specified

Application process:

1. Micro-Generation Project Interconnection Application, including single-line diagram, site plan, electrical permit
2. Micro-Generation Interconnection and Operating Agreement
3. Meter Installation

System installation

Customer & Program Costs/Benefits

Bill Determination/Rate Structure

- **Compensation is on an annual basis** (no concept of monthly credits carried month after month since program is not net-billed monthly, rather annually). Anniversary based on utility-approval date for system
- The incentive for the net electricity exported is reflective of the current avoided cost (2013 rate application) of new electrical generation in the territory. Rate will be evaluated 2 years later
  - 21c/kWh for grid-interconnected customers
  - 30c/kWh for isolated communities (reflective of diesel gens)
  - (for reference, the residential rate for grid-interconnected and isolated is 12.14c/kWh)

Annual metering and compensation (and exclusion of monthly-carry-over of credits) encourages customer energy efficiency given that every kWh exported is summed into the annual payout, such that less energy usage directly affects the annual payout (unlike with monthly metering, which generally will create a scenario where credits will be used up).

Responsibility for associated net metering costs
Customer Costs

- interconnection costs and any potential transformer upgrade requirements

Utility Cost:

- Utilities will be limited to paying for and maintain the meter

Regulatory Treatment

Evaluation
Government and Utility to **evaluate the policy two years from the effective date** to ensure its implementation is meeting the set objectives.
At this point, no evaluation has been performed.

Other information
Solar Energy Pilot:
An evaluation of solar projects in YK yielded an average of 11.5% capacity factor (approximately 1,000Wh/1kW/yr.).
They estimated that payback periods for micro-generation customer with a 5kW PV system, payback would likely be >20years.
They concluded that PV systems are price competitive in remote communities that use diesel generation, but "will likely never be economically competitive with legacy hydro generation", which means that there is no economic case for grid-interconnected PV systems.

NM Experience

N/A

Sources

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Avoided costs:
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2009 paper
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NAVIGANT

NM Jurisdictional Review

Jurisdiction	Drivers for NM	Program Design/Framework	Customer & Program Costs/Benefits	Regulatory Treatment	NM Experience	Sources
Nunavut (NM - policy still under development by Nunavut Government)	Qullig Energy is the sole provider of electricity in Nunavut. Serving Nunavut's 17,000 customers through 25 diesel generators in 25 communities. Each community has its own independent grid, and all are entirely dependent on fossil fuels. Qullig Energy uses community based rates, but with its 2014/2015 (according to its 2012/2013 Annual Report) rate application plans to move towards a territorial based rate Its 2014 rate schedule (effective May 1, 2014) still presented community-based rates, ranging from 60c/kWh (Iqaluit) to 114c/kWh (Kugaaruk). Peak load is in 2012/2013 was 34MW, and annual electricity generation was 177GWh. **Generation Capacity:** <table><tr><th>Dec 2012</th><th>MW</th><th>%</th></tr><tr><td>Diesel</td><td>61</td><td>100%</td></tr><tr><td>**Total**</td><td>61</td><td>100%</td></tr></table>	**Legislation**: Qullig Energy is subject to the Qullig Energy Act, and the Utility Rates Review Council Act.		2012/2013 Annual Report: • "A Net Metering Policy is currently being developed to allow small amounts of alternative energy from our customers to be introduced to the power grids. The limit on any Net Metering installation will be 10 kW with additional limits based on the individual communities as to the total amount of alternative energy QEC will accept" 2014/15 General Rate Application: • *"QEC also researches emerging alternative energy technologies to determine if they can be incorporated into the capital planning cycle"* • *"…. continued work on a potential hydroelectric development outside Iqaluit"*: o Qullig Energy will conduct a draft environmental impact statement for a potential hydroelectric site. • In 2009, Iqaluit had a distribution system upgrade for its substation from 5kV to 25kV. The new 25kV is expected to meet the requirements of potential future interconnection of renewable energy sources or the hydroelectric plan.		2009 Discussion Paper: http://www.energy.gov.yk.ca/pdf/ipp_net_metering_discussion_paper_nov2009.pdf **2012/2013 Annual Report:** http://www.qec.nu.ca/home/index.php?option=com_docman&task=doc_download&gid=1106 **2014/15 Rate Application:** http://www.qec.nu.ca/home/index.php?option=com_docman&task=doc_download&gid=1086

NAVIGANT

NM Jurisdictional Review

Jurisdiction

Northwest Territories

Net Metering

Drivers for NM

Driving force
Net-billing pilot program started voluntarily by utilities, then supported/encouraged by ENR to transition into a NM project.

Market:
NWT Power Corp (NTPC, a public utility) generates most of the electricity in NWT, and also distributes to most communities (aka Thermal zone: served by diesel gens)
Northland Utilities (NUL, an IOU) serves Yellowknife and the communities in the Hay River area (aka Hydro zone)
The NW PUB regulates NTPC and NUL.

Net Billing Pilot:
NTPC/NUL initiated a 2-yar net billing pilot in 2010, with the intent to better understand issues associated with customer self-generation and understand DG policy initiatives. The utilities attained support from the Dept. of Environment and NR (ENR). After 2 years (2012) the ENR released its Solar Energy Strategy 2012-2017, which outline net-metering relevant actions points.
The net billing pilot was structured such that any excess generation would automatically be sold to the utility (no carry-over of credits)

Generation Capacity:

Dec 2012	MW	%
Diesel	37	30%
Natural Gas	22	18%
Renewable	65	52%
Total	124	100%

Program Design/Framework

Legislative Considerations
NTPC required to serve areas of the territory not served by an IOU

Eligibility:
- 5kW
- Small, commercially proven wind generators, mini-hydro, solar, or other renewable energy technologies
- *"As the program is intended for small renewable energy generation, the size of such generation would generally not exceed 5kW"* though systems greater than 5kW may be accommodated as long as they don't pre-empt access by smaller projects)
- All customers (incl. government customers, thought their effective eligibility is delayed till Phase 2 of the utilities' 2014/15 rate application)

Meter aggregation: Not addressed
Subscription limit:
- For Thermal zone: 20% of the annual average demand for each community (20% determined from NTPC system simulations)
  - The cumulative NTPC (thermal zone) average load was 13MW, such that 2.6MW was the limit.
  - (March 31, 2014) 202kW (all PV) of NM capacity, which is 1.6% of the average load
  - Fort Simpson had installed 119kW (70% of its allotted 175kW)
- For Hydro zone: limits determined annually, on the basis of system impacts

Application process:
Single application process for all system sizes:
- Submit "Grid-Connect Micro Generation Application" form (along with single line diagram, site plan)
- Upon approval form utility; conduct an electrical inspection, and get Site & Field Verification approval from utility

All projects are exempted from the standby service charge. Initially –under the net billing pilot- thermal zone customers were subject to the standby service charge. This charge was developed to provide NM customers a fair allocation of costs to maintain diesel generation for it to provide standby service to those customers, and to protect other customers from subsidizing NM customers' fair share of standby generation. NTPC's reasoning for dropping the charge, was that given a 5kW limit, customers would still purchase a material portion of their electricity from the grid, thereby contributing to those costs.

For comparison, given a 10kW limit, NM customers would be –to a greater amount- partially self-sustaining; in this case there is a better case for charging the standby charge since they would contribute minimally to the diesel costs.

Customer & Program Costs/Benefits

Bill Determination/Rate Structure
- Customers in NM receive a credit in kilowatt hours equal to the excess energy.
- Excess generation can be carried month over month as kWh credits.
- The anniversary date, on which remaining credits on the account will be reset to zero, is March 31

Responsibility for associated net metering costs
Customer Costs:
- Responsible for all cost incurred on their side of the meter:
- All costs associated with purchasing and installing the renewable energy system.
- Any costs associated with permits, inspection or other requirements
- Customers continue to be billed the basic monthly charge.

- Utility Costs
- O&M costs for the meter, and for the transmission/distribution system
- Utilities will cover all capital and installation costs for changes to their own infrastructure, necessary to connect a proposed generation project.

Regulatory Treatment

Cross subsidization issues (see PUB Approval of NM)
Potential of Cross-subsidization:
The PUB identified the following as having potential to cause rate impacts:
- Meter/metering costs
- Customer communications/administration
- Incremental costs from real-time monitoring of projects
- Planning for new generation capacity, from a firm-capacity perspective
- Fixed costs for generation/transmission/distribution not recovered due to netting
- Compensation of hydro customers at a rate reflective of displaced diesel and hydro

The PUB concluded that these could be assessed better at Phase 2 of the 2014/15 rate application, though until then the PUB asked utilities to impose a charge to help defray those NM-relevant incremental costs.

Other information
NWT Solar Energy Strategy 2012-2017
Action points:
- 5: the Govt. & utilities are to develop a program for grid-interconnected PV systems
- 6: deploy solar systems sized up to 20% of the avg. load at diesel communities
- 7: investigate effective ways to size up to 75% of load
- (though here the Govt. encourages utility action, initially this started as voluntary utility program)

Funding:
- Funding is available from the Arctic Energy Alliance to help residential and business customers purchase their renewable energy technology system. Funding for community projects is available from the Department of Environment and Natural Resources.

Net Billing to Net Metering:
- Implementation approved by the Public Utilities Board (PUB) as of January 31, 2014, following a 3 year period of a net billing pilot capped at 50kW.

Net Billing Program Debate:
- NTPC originally requested to exclude the Hydro zone from the program, citing different variable generation costs at the margin in thermal versus hydro zones.
- An intervener noted that in the hydro zone, customers would effectively strand one renewable resource for another, and that stranded hydro costs should only be borne by Hydro customers. (In essence, there is environmental/economic reason for providing the program to hydro customers.
- NUL, the PUB, and another intervener agreed that even in Hydro communities, NM could potentially assist in deferring future power plant need. NUL noted that PV generation could *"assist the Hay River [diesel station] during the Taltson Hydro annual maintenance shut down"*
- An intervener proposed rolling reset dates. The PUB and NTPC argued that it would significantly increase the administrative burden for tracking and managing those.
- An intervener noted that in hydro communities, NM customers would be compensated at a NM rate reflective of both displaced diesel and hydro generation, which would not be fair. The PUB agreed, but noted that the difference would be insignificant, though asked the utilities to address it if it became material.

NM Experience

Participation:
NUL: 3 customers (July 31, 2013)
NPTC: 202kW –all solar (March 31, 2014)

Sources

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Application Process:
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Application Form:
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NAVIGANT

NM Jurisdictional Review

Jurisdiction

Arizona

Renewable Energy Standard and Tariff – Net Metering

Drivers for NM

Driving force:
In 2006, the ACC approved the Renewable Energy Standard and Tariff (REST).
Driven by renewable goals. NM was created from REST.

Market:
The Arizona Corporation Commission (ACC) oversees the electric power industry in Arizona. The ACC regulates IOUs and co-ops (not munis, and distrital utilities). Arizona Public Service Company (APS) is the largest electricity utility in Arizona.

Generation Capacity:

July 2014	MW	%
Coal	6,157	22%
Hydro	2,720	10%
Natural Gas	13,557	49%
Nuclear	3,937	14%
Petroleum	91	0%
Pumped Storage	216	1%
Renewable	909	3%
Total	27,587	100%

APS: Total Generation Capacity: 9,186MW (April 2014)

Program Design/Framework

Legislative Considerations
SRP and municipal utilities do not fall under the jurisdiction of the ACC, and therefore are not subject to the state rules.

The ACC requires that net metering charges be assessed on a non-discriminatory basis. Any new or additional charges that would increase an eligible customer-generator's costs beyond those of other customers in the rate class to which the eligible customer-generator would otherwise be assigned must be proposed to the ACC for consideration and approval.

REST (AZ Administrative Code):
- REST was approved by the ACC, and established a requirement that 15% of retail energy sales from ACC utilities need to come from renewable resources by 2025, and 30% of that 15% baseline must come from DG resources.

One of the incentives that developed from REST was the development of the net metering:
The current net metering regulation was passed in 2008
NM (AZ Administrative Code):
- "Electric utilities may include seasonally and time of day differentiated Avoided Costs rates for purchases from Net Metering Customers, to the extent that Avoided Cost very by season and time of day"

More incentives:
Federal level:
- Investment Tax Credit, for rooftop PV, provides financial benefit amounting to 30% of a solar project's value.

State level:
- Property and sales tax exemptions
- Tax credits for installing PV
- NM
- Up Front Incentives (UFIs)

UFIs: provided incentive since 2008 at $3/W, and since 2010 gradually decreased to $0.1/W in 2013, and has been phased out due to the high participation.
Eligibility:
- ACC has no specified kW limit: System has a generating capacity less or equal to 125% of customer's total connected load
- Technologies: all renewables and clean, CHP, fuel cells
- available to customers
- Third parties allowed

Meter aggregation: Not addressed
Subscription limit: No limit specified

Application process:
Single process for all NM systems

Customer & Program Costs/Benefits

Rate Structure/Bill determination
- Basic charges are included in bill, and cannot be credited off
- Any excess generation will be carried over to the customer's next bill (valued at the utility's retail rate) as a kilowatt-hour (kWh) credit.
- For customer using TOU, crediting will also follow TOU structure, such that credits can be classified as off or on-peak kWhs.
- The customer owns the Renewable Energy Credits (REC), though they are transferred to the utility in exchange for annual payout

Compensation rate
- Annually, excess kWh are paid at avoided-cost rate (2.9c/kWh +/- <2% for off/on peak)
- The avoided costs is calculated annually as part of the corresponding tariff application

Regulatory Treatment

Cross subsidization issues
- ACC ordered a $0.70 per kW charge for all residential net metered systems installed on or after January 1, 2014. (December 2013, in response to an application from the Arizona Public Service Company (APS) to address cost shifting)

APS Cost Shift Application:
- Reported that for 2012-2013, saw an average of 500 application per month
- (more recent data showed that in 2014 it went up to 600/month)
- The cause of these was the combination of NM, federal/state incentives, and the solar resources.
- As participation update has grown, so have APS's concerns with cross-subsidization. Cross subsidization is most apparent for the residential consumer class.
- On average, the cost shift each year is approximately $1,000/residential NM system; such that in 2013, the costs shifting to non-NM customers was $18M
- APS proposed two solutions:
  - Introduced a demand-based rate under a TOU tariff
  - A buy-all, sell-all approach under a different tariff rate

Evaluations:
- Under the ACC rules, each utility must file an NM annual report, and as of 2014 a quarterly report outlining participation rates and revenue collected through the $/kW premium
- The ACC noted that a series of solutions arose from interveners; enforcing a service charge, demand charge, or standby charge.
- Another possible solution was to have NM customers charged for all the kWh they consume, but receive a credit for all the kWh produced
- ACC noted that because residential rates are typically designed to recover much of the utility's fixed costs through volumetric energy rates, NM customers effectively pay less for these fixed costs. The additional fixed costs then must be picked up by non-NM customer either through higher energy rates or through APS's Fixed Cost Lost Recovery mechanism.
- ACC rejected both of APS suggestion, noting that they were not revenue neutral and APS did not propose a system of returning the incremental revenue to non-NM customers.
- (in a three to two vote) ACC decided to impose a fixed charge of $0.70/kW to new NM customers as a short term solution until the next rate setting period.

2014 SC Energy Advisory Committee report (for source see SC):
- As of Q2 2012, 80% of residential installations where third party owned

NM Experience

NM (Dec31, 2013, data only for APS):
- 375MW (149MW of residential)
- 20,696* (20,582 of residential NM customers)

*Assumption: 17,696 + 6mth x (500/mth))

See 2013 RES Compliance Report, pg. 3

Sources

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NM Jurisdictional Review

Jurisdiction

Washington

Net Metering

Drivers for NM

Driving force:
The development of renewables in Washington state traces back to policy actions in the 1980s. In 1998, the legislature passed bill 2773 that directed utilities to make NM available to customers. The intent of the bill was to encourage private investment in renewable energy resources

Market:
Washington's Utilities and Transportation Commission (UTC) is the regulator body. UTC regulates all IOUs.

The three IOUs (Avista, Pacific Corp and Puget Sound) provide NM programs

Generation Capacity:

July 2014	MW	%
Fossil Fuels	4,894	16%
Hydro PH	314	1%
Nuclear	1,132	4%
Other	16	0%
Renewables	24,509	79%
Total	30,865	100%

Program Design/Framework

Legislative Considerations
(1998) Substitute House Bill 2773 – "Net Metering for certain renewable energy systems" determined that it is in the public interest to "encourage private investment in renewable energy resources". Initial capacity limit is 25kW.

(2000) House bill 2334 required at least 0.05% of the cumulative generation capacity of NM system to come from solar/wind/hydro.

(2006) Amendments to bill 2334: Biogas added, capacity increased to 100kW

The Energy Independence Act (2006) set an RPS of 15% to 2020. This RPS is limited by cost caps, exempting utilities from the RPS if it spends >4% of its retail revenue on the incremental costs of renewables.
NM of Electricity (legislation)
- The utility "shall not charge the customer-generator any additional standby, capacity, interconnection, or other fee or charge unless the commission…determines…that the electric utility will incur direct costs associated with interconnecting or administering NM systems that exceed any offsetting benefits associated with these systems"
- "Net policy is best serve by imposing these costs on the customer-generator rather than allocating these costs among the utility's entire customer base"

UTC Order UE-112133:
- UTC order concludes that third-party ownership is permissible under Washington's

State Policy: Customer owns renewable energy credits

Eligibility:
- 100kW
- Technologies: all renewables and clean, CHP, fuel cells
- Third parties allowed

Meter aggregation:
- Meter aggregation (within utility territory) is allowed.
- Credits are used first to the customer's account and then equally divided among other meters

Subscription limit: 0.5% of utility's 1996 peak demand:

Application process
Simple process:
- <25kW will proceed with a standardized form in an expedited process
- Lower application fee ($100)
- No switch connect required

Complex process:
- >25kW, uses more complex interconnection requirements
- Application fee ($500

Customer & Program Costs/Benefits

Rate Structure/Bill determination
- Basic charges are included in bill, and cannot be credited off
- Billed for net electricity, if zero, only charge for basic charges
- Any excess generation will be carried over to the customer's next bill as a kilowatt-hour (kWh) credit
- Customer owns Renewable Energy Credits (REC)

Compensation rate
- Annually on April 30, excess kWh are reset to zero

Responsibility for Costs
Utility:
- Meter, metering, program administration

Customer:
- meter installation, connection equipment, all costs to meet interconnection requirements, grid upgrades needed

Regulatory Treatment

Evaluations:
Washington Legislature Bill HB 2176:
The legislature rejected this bill
It would entail that if an IOU offered a leased energy program (financing for NM systems), then on other entity could offer leases to the utility's customers
Essentially, the bill would have set up a monopoly on distributed system in Washington

Other information:
Renewable Energy Investment Cost Recovery Incentive Program:
- (2005) Legislature create the cost-recovery program to promote renewables
- The program provides at least 15c/kWh, which is then factored with a multiplier dependent on the technology
- In 2009, community solar projects were added (incentive of 30c/kWh)
- Covers up to $5,000/annually

NM Experience

NM (June 2014):
13.89MW
- Avista (0.99MW)
- PSE (11.4MW)
- Pacific (1.5MW)

The current caps are:
- Avista (7.6MW)
- PSE (22.4MW) – has surpassed 50% of its cap
- Pacific (4.55MW)

See UTC-Regulation of third party owners of NM facilities, pg. 8

Sources

Net Metering - legislation
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Utilities and Transportation Commission (UTC) – Net Metering
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1999 UTC Report:
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(July 30, 2014) UTC – Regulation of third party owners of net metering facilities:
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NAVIGANT

NM Jurisdictional Review

Jurisdiction

Idaho

Net Metering

Drivers for NM

Driving force:
IPC, by far the largest utility in Idaho, accounts for 73% of the state's generation capacity.
In 1983, the Idaho Public Utilities Commission (IPUC) first ordered IPC to offered NM. Since then, the IPUC has issued several orders with amendments to NM. Idaho Power Company (IPC) issued the NM policy, and was approved by the Idaho Public Utilities Commission (IPUC) in 2008.

Idaho does not have a statewide net-metering policy, though the state's 3 IOUs have developed their metering policies.

The IPUC regulates IOU, but not munis, co-ops.

Generation Capacity:

July 2014	MW	%
Renewables	3,779	77%
Fossil Fuels	1,133	23%
Other	15	0%
Total	4,927	100%

Program Design/Framework

Legislative Considerations
<u>IPUC Order 29094 and Order 28951 (2002):</u>
- Created a schedule specific to NM
- IPUC approved a 2.9MW limit (in order to minimize potential cost shifting)
- In 2002, only 3 customers were using NM

The IPUC approved IPC's NM policy in 2008.
- Payout allowed at:
  - Retail rate (res/small comm)
  - 85% of avoided costs (industrial)

A revision was approved in 2013 (effective 2014)
- Credits expire after 12 months

Eligibility:
- 25kW (residential/small commercial)
- 100kW (industrial)

<u>Meter aggregation:</u>
Allowed (though under very strict guidelines, and $10 fee.
Guidelines:
- Accounts are held by the same customer
- Meters are on or contiguous (incl. property separated by a public or rail road)
- Meter served by same feeder
- Credits are transferrable only if under same class schedule
- Transfer notice to utility must be given In January

<u>Subscription limit:</u>
- 1.52MW (Avista Utilities, 0.1% of peak demand)
- No limit (IPC) – previously capped at 2.9MW
- 714kW (Rocky Mountain Power, 0.1% of 2002 peak demand)

Application process
Single application process:
- Application form (fee)
- IPC Feasibility review
- Installation, and electrical inspection
- System Verification form

Customer & Program Costs/Benefits

Rate Structure/Bill determination
- Basic charges are included in bill, and cannot be credited off
- Customer is billed for the net electricity consumed
- Any excess generation will be carried over to the customer's next bill as a kilowatt-hour (kWh) credit

Compensation rate
- Credits expire (IPUC approved in Sept 2013) on Dec 31.

Responsibility for Costs
<u>Utility:</u>
- Meter, metering, program administration

<u>Customer:</u>
- All costs associated with interconnection facilities, studies, and reviews.
- incremental costs associated with company equipment needed as a result of NM system

Cross subsidization issues
IPC identified the potential for cross-subsidization in its 2013 NM report:
- IPC analyzed the current state of its bill structure noting that Residential/Small General Service are billed through a $5 basic charge + volumetric energy rates. It noted though that fixed residential customer costs total $20.92 (such that the majority of fixed costs are recovered through volumetric charges.
- Under this rate design, NM customers reducing their volumetric consumption may not entirely contribute to their fair share of fixed costs.
- At the current participation rate (408 + 20 pending projects), IPC does not purport that cost shifting is currently impacting customer rates.

However, the potential for cost shifting renders the current rate design for NM "unsustainable" since the retail rates were not design to recover costs of providing NM.

Regulatory Treatment

Evaluations:
<u>Application IPC-E-12-27:</u>
In November 2012, IPC was filed an application with the IPUC as it neared the 2.9MW limit. IPC proposed:
- *Capacity cap*: An expansion to 5.8MW since generation was approaching 2.9MW
- *Pricing*: Pricing change to reflect cost of service (basic charge for NM customer to increase from $5 to $22.49, a demand charge of $1.48/kW and a decrease in NM retail charges to 4.85c/kWh)
- *Excess net energy*: Replacing financial payment with kWh credits, and expire on Dec 31

In its decision, the IPUC denied nearly all of IPC's proposal:
- *Capacity cap*: The commission ruled that a cap" may disrupt and have a chilling effect" on NM.
  Then, the IPUC went further and lifted the subscription limit limit altogether.
- *Pricing*: The IPUC noted that NM customers "have some characteristics that could justify moving them into a separate rate class" but decided against it given state energy policy and the possibility of larger customers taking advantage of the lower retail prices IPUC noted that "[NM customers] do escape a portion of the fixed costs and shift the cost burden to other customers in their class…[but]…more work needs to be done to establish the correct customer charge for [NM customers]"
  Overall, the IPUC noted that this proposal was a dramatic change
- *Excess net energy*: IPUC: "while we want to encourage NM, we believe financial credit or payment may incent potential NM customer to overbuild their system" (consider that they don't size a NM system to customers' needs)

IPUC found it "fair, just and reasonable for the kWh credit to indefinitely carry forward to offset future bills"
In 2013, the IPUC directed IPC to file an annual status report regarding NM
On Dec 31, 2013, IPC filed its first annual report:
<u>Billing System</u>
- IPC noted that incorporating the new NM practices (such as negative consumption, and meter aggregation) would entail a dramatic change to their billing system, and can potentially be time-intensive and costly (quoted $120-200K from IT/consulting).
- Further, IPC's IT department and 3rd party consultants determined that the system cannot be customized to accommodate for automated meter aggregation
- The status quo is to manually make edits into their billing system
- IPUC will continue to monitor the ability of their system to incorporate NM practices.

<u>System Reliability</u>
- At their current level, there is no significant impact on the distribution system. Approximately 2 NM system per feeder

Other information:
- IPC offer three options for interconnecting renewable generation

NM Experience

NM (Dec 31, 2013):
Only IPC:
428 projects (345 PV, 73 Wind, 10 others)
2.97MW (2.24 PV, 0.58 Wind, 0.15 others)

See IPC 2013 NM Report

Consider IPC generation capacity is 3,594MW (75% of Idaho's)

Sources

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NM Jurisdictional Review

Jurisdiction

Oregon

Net Metering

Drivers for NM

Driving force:

House Bill 319 was passed in 1999. The bill was introduced by the Oregon Solar Energy Industry Association (OSEIA) and was meant only for public utilities

The Public Utility Commission of Oregon (PUC) regulates the state's IOUs (only Portland General Electric [PGE] and Pacific Corp.). The PUC does not regulate public utilities (there are 36 public utilities).

Oregon has established separate net-metering programs for the state's primary investor-owned utilities (PGE, Pacific), and for its municipal utilities and electric cooperatives

Generation Capacity:

July 2014	MW	%
Renewables	11,964	77%
Fossil Fuels	3,595	23%
Total	15,546	100%

Program Design/Framework

Legislative Considerations

The 2007 RPS was approved in 2007:

- 25% by 2025 for PGE, Pacific and Eugen Water, Electric Board (EWEB)

NM Bill for public utilities (ORS 757.300, Senate Bill 84):

- "An electric utility…may not charge a [NM customer] a fee or charge that would increase the [NM customer]'s minimum monthly charge to an amount greater than that of other customers in the same rate class…. [unless] the [PUC] may authorize an electric utility to assess a greater fee or charge"

NM Bill for IOUs (ORS 860-039-0005):

- Regulation is very similar to ORS 757.300
- "by April 1, each public utility must file...[a net metering report]", only PGE & Pacific file NM reports, not public utilities

PUC Order No. 08-388 (July 2008):

- **Third parties** are allowed to finance, build, own and operate a PV system for customers.

Under regulation, utilities with >25K customer headquartered outside of Oregon, that already provide a NM policy, are exempt from ORS 757.300:

- Oregon residents served by Idaho Power Company (IPC) NM customers are subject to Idaho.

Eligibility:

- Renewables/Clean technologies, fuel cells, geothermal, marine
- 25kW (IOUs/Public) – residential
- 2MW (IOUs) – non-residential
- Third parties allowed

Meter aggregation: [IOUs] Allowed

Guidelines:

- Accounts are held by the same customer
- Meters are on or contiguous
- Meter served by same feeder

Subscription limit:

- 0.5% of public utility's peak load (beyond will be assessed by PUC)
- No limit specified for PGE and PacifiCorp

Application process

Three levels of review; though all with the same application form

- Level 1 NM Interconnection Review: <25kW
- Level 2 NM Interconnection Review: <2MW
- Level 3: NM Interconnection Review: if fails to comply w/ all level 2 requirements.

Customer & Program Costs/Benefits

Rate Structure/Bill determination

- Basic charges are included in bill, and cannot be credited off
- Customer is billed for the net electricity consumed
- Any excess generation will be carried over to the customer's next bill as a kilowatt-hour (kWh) credit
- Customer owns Renewable Energy Credits (REC), though if customer enrolled in Energy Trust incentives, they are transferred

Compensation rate

- Annual billing ends on March 31 (or as noted in agreement)
- [Public Utilities] Any remaining credits are granted to the utility for distribution to customers enrolled in the utility's low-income assistance programs, credited to the generating customer, or dedicated to an "other use"
- [IOUs] Any remaining credits are granted to the utility for distribution to customers enrolled in the utility's low-income assistance programs valued at the annual avoided cost rate.
  - o PGE collected excess 508,862kWh in F2013, valued at 3.18c/kWh of avoided costs, for a total of $16,161, which was transferred to Oregon Heat for the benefit of low-income customers.
  - o Pacific collected excess 615,084 in F2013, valued at 2.88c/kWh of avoided costs, for a total of $17,728, which was transferred to Oregon Heat for the benefit of low-income customers.

Responsibility for Costs

Utility:

- Meter, metering, program administration

Customer:

- Interconnection costs for applicable for Level 2, 3, but not Level 1

Regulatory Treatment

Evaluations:

Independent presentation by Aaron Lindenbaum (CUB Policy Centre)

- 36 public utilities in Oregon (the only two IOUs are PGE and Pacific)
- 25 utilities had a 25kW limit (studied 32 utilities)
- Tillamook PUD is the only that allowed infinite rollover of credits

PUC (June 2014) Draft Report on Solar Initiatives in Oregon:

- "Net Metering may shift some of the utility's fixed costs from program NM customers to other ratepayers. This cost shift limits the economic potential for solar form net metering"
- "Net metering customers enjoy a reduced electric bill, but in doing so they avoid paying some these fixed costs. The Utility must recover them form other ratepayers.
- "This has been a small concern in Oregon, given the limited capacity of distributed solar generation"
- "PGE stated that 6.4c/kWh charge would have to be deducted from the bill credit given to NM customers to recover distribution costs from NM customers"
- In January 2014, PGE suggested a NM charge of $4.25/month to the Utah PUC. The equivalent fee in Oregon would have to be $6.90/month.

Other information:

Customers retain the renewable energy credits

NM Experience

NM (Dec 31, 2013):

PGE:

- 3,475 projects (3,425 Solar, 42 Wind, 8 others)
- 28.4MW, (27.6 Solar, 0.6 Wind, 0.2 others)

Pacific:

- 3,407 projects (3,367 Solar, 22 Wind, 18 others)
- 28.2MW, (26.3 Solar, 0.1 Wind, 1.8 others)

See 2013 Pacific and PGE Reports

Sources

NM Bill for public utilities (ORS 757.300)
https://olis.leg.state.or.us/liz/2014R1/Measures/Text/HB4042/Enrolled

NM Bill for IOUs (ORS 757.300)
http://arcweb.sos.state.or.us/pages/rules/oars_800/oar_860/860_039.html

2007 RPS:
http://www.puc.state.or.us/consumer/Renewable%20Portfolio%20Standards%202012.pdf

Pacific NM Reports:
http://apps.puc.state.or.us/edockets/docket.asp?DocketID=17392

PGE NM Reports:
http://apps.puc.state.or.us/edockets/docket.asp?DocketID=17457

PGE Unused kWh Report 2013:
http://edocs.puc.state.or.us/efdocs/HAQ/re79haq14913.pdf

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http://edocs.puc.state.or.us/efdocs/HAQ/re63haq103156.pdf

Aaron Lindenbaum Presentation:
http://solaroregon.org/solar-now/speakers/net-metering-in-oregon-policy-vs.-practice

Oregon PUC rules in favor of third party solar projects
http://www.hunton.com/files/News/e1948fcb-a98f-4ed0-b3d9-71496af163eb/Presentation/NewsAttachment/b7d7dc5a-2e83-48e5-b39a-d403077f06aa/OPUC_Client_Alert.pdf

PUC Report:
http://edocs.puc.state.or.us/efdocs/HAH/um1673hah75059.pdf

NAVIGANT

NM Jurisdictional Review

Jurisdiction

South Carolina

Net Metering

Drivers for NM

Driving force:
In Dec 2005, the SC Office of Regulatory Staff asked the SC Public Service Commission (PSC) to address NM, as a result of the federal Energy Policy Act of 2005.

In May 2008, the PSC directed IOUs to provide NM for customers by July, 2008. The PSC directive did not include a framework for the development of their NM program. The PSC requires Duke Energy (DE) and SC Electric & Gas (SCEG) to provide a TOU and flat rate NM options.

In April 2014, SB1189 dictated program structure to the NM programs for all utilities (with >100K customers), creating the "Distributed Energy Resource Program".

There are 3 IOUs (DE, Lockhart, SCEG, 1 state owned utility (Santee Cooper) and 41 public utilities

DE and SCEG supply to 50% of customers.

Generation Capacity:

July 2014	MW	%
Renewable	1,770	8%
Fossil Fuels	11,973	52%
Nuclear	6,508	28%
Hydro PS	2,716	12%
Total	22,966	100%

Program Design/Framework

Legislative Considerations

(April 2014)S.B. 1189, Chapter 40: Net Energy Metering:
- All utilities with more than 100,00 customers, excluding cooperatives
- Cooperatives are required by S.B. 1189 to examine NM policies but are not bound by law to implement new programs.

Eligibility:
- Renewable/clean, geothermal, tidal/wave
- must be owned, leased, or operated by the customer
- 20 kW for residential
- 1,000 kW or 100% of demand for non-residential

Meter aggregation: not allowed
Subscription limit: 2% of average retail peak demand for previous 5 years

Application process
- NM application
- Interconnection agreement
- Single line diagram, certificate of insurance
- Utility On-site inspection

Customer & Program Costs/Benefits

Rate Structure/Bill determination
Compensation rate
- If excess electricity, it is credited and the kWh credits roll over to the next month.
- Annual pay out to customer zeros out monthly carry-over
- For SCEG; the anniversary date is Nov 1
- For DE, the anniversary date is March 1

Order No. 2014-508:
- Duke Energy Carolinas (DEC)and Duke Energy Progress (DEP), which serve different service areas, though under the same parent company, requested to allow accumulated excess energy to be reset to March 1, rather than June 1 for DEC and May 31 for DEP.
- Customers expressed concern that given those dates, customers had to forfeit more excess generation since they are likely to accumulate credits in the months before those dates.
- The PSC consented and reset dates to the more appropriate March 1

Regulatory Treatment

Cross subsidization issues
In 2013, the PSC initiated a review process of its distributed generation profile.
The Energy Advisory Council (Public Utilities Review Committee) released its Distributed Energy Resources Report in January 2014 and served as a guidance for the April 2014 SB 1189 bill. These are the highlights of the report:
- Utility fixed costs represent 63% of their average cost to serve customers (37% is variable), from a residential rate design perspective though; only 8% of the average bill accounts for the basic, fixed charge.
- When residential customers install solar PV, the reduction of the users volumetric electricity usage results in an under-compensation for the utility
- DG, using the current residential rate structure presents:
  - Advantages: Rate design simplicity, predictability for utility/customers, incentivizes
  - Challenges: cost shifting to utility and non-NM customers
- Proposed several solutions in terms of rate design:
  - A new DG residential rate
  - Modifying NM rates (adding a standby charge, or demand charge
  - Buy all, sell all approach (replacing the 'retail' price transaction with a 'wholesaler' approach)
  - Instituting a net revenue loss adjustment.

Evaluations:
Act 404/H3395 (2008) required the SC Office of Regulatory Staff to develop a report on the current status of NM in SC and provide recommendation for IOUs on NM regulations, the following were the recommendations:
- Separate NM programs from purchase power programs
- (1) Standardize NM program structure across utilities
- (2) For residential customers, modify the IOU flat rate to reflect 1:1 standard retail rates for excess energy credits
- (3) Acknowledge that recommendation #2 may create cross-subsidization and impact a utility's cost of service, allow utilities to recover these costs, subject measurement and verification of these costs
- (4) eliminate stand-by charges
- (5) allow renewable energy generator to retain ownership of Renewable Energy Credits
- (6) Require annual reporting to SC Office of Regulatory Staff and SC Energy Office of the number of NM customers by renewable energy generator type, in order to allow for continuing assessment of NM programs
- (7) Formally revisit the NM process within 4 years

Other information:
SCEG offers only two alternatives: Buy All/Sell All, or NM
DE offers only three alternatives: Buy All/Sell All, Net metering, or Parallel Generation

NM Experience

NM (Dec 31, 2013):
- 299 projects (298 PV, 1 wind)
- 4.6MW

See Clean Energy Comment

Sources

South Carolina Net Metering Report (2008)
http://www.energy.sc.gov/files/FinalNetMeteringReport.pdf

S.B. 1189, Chapter 40: Net Energy Metering
http://www.scstatehouse.gov/sess120_2013-2014/prever/1189_20140521.htm

SCEG, Net Metering:
https://www.sceg.com/for-my-home/renewable-energy/solar-for-your-home

DE Generate your own power:
http://www.duke-energy.com/generate-your-own-power/sc-main.asp

Duke Energy Rate:
http://www.duke-energy.com/pdfs/SCRiderNM.pdf

SC Utility Guide:
http://www.energy.sc.gov/files/view/2012GuideUtilitiesSC.pdf

DEC Net Metering Report
http://dms.psc.sc.gov/pdf/matters/F297C520-155D-141F-23B612CCF597547E.pdf

DEP Net Metering Report
http://dms.psc.sc.gov/pdf/matters/4AF0410A-155D-141F-23916B33DA569270.pdf

SCEG Net Metering Report:
http://dms.psc.sc.gov/pdf/matters/83D8C040-155D-141F-2351602C34A9F361.pdf

Order No. 2014-508
http://dms.psc.sc.gov/pdf/orders/45EB5A92-155D-141F-2339581D7C4E6374.pdf

Clean Energy Comment:
http://dms.psc.sc.gov/pdf/matters/C74133C0-155D-141F-23314C8AC7BE64F8.pdf

Distributed Energy Resources Report (Jan 2014):
http://www.scstatehouse.gov/committeeinfo/EnergyAdvisoryCouncil/EAC%20Report%201-14-14.pdf

Freeing The Grid 2013 Report:
http://freeingthegrid.org/wp-content/uploads/2013/11/FTG_2013.pdf

NAVIGANT

NM Jurisdictional Review

Jurisdiction

Vermont

Net Metering

Drivers for NM

Driving force:
In 1998, legislative required utilities to provide NM.
This legislation was followed by revisions in 1999, 2002 and 2008

In 2014, Bill H.702 (Act 99) required the Public Service Department (PSD) to submit a NM Evaluation Report. This bill requires the establishment of a revised NM program by January 1, 2017.

Market:
Vermont has 17 electric distribution utilities

Generation Capacity:

July 2014	MW	%
Renewables	534	43%
Fossil Fuels	99.8	8%
Nuclear	604	49%
Total	1,239	100%

Program Design/Framework

Legislative Considerations
30 V.S.A. § 219a."Self-generation and net metering"
"The Board may raise the 4.0 percent cap. In determining whether to raise the cap, the Board shall consider the following:

- (i) the costs and benefits of NM systems already connected to the system; and
- (ii) the potential costs and benefits of exceeding the cap, including potential short and long-term impacts on rates, distribution system costs and benefits, reliability and diversification costs and benefits"
- A utility "shall charge the customer a minimum monthly fee that is the same as for other customers of the electric distribution company in the same rate class, but shall not charge the customer any additional standby, capacity, interconnection, or other fee or charge"

Act 99 (2014) amended VT's NM, w/ the following:

- Increase of 4% to 15% of subscription limit
- Adder for >15kW decreased to 20c/kWh

Eligibility:

- Renewable
- 2.2 MW for military systems;
- 20 kW for micro-CHP
- 500 kW for all other systems
- Third parties allowed
- All customers are required to obtain a "Certificate of Public Good"

Meter aggregation: "Group" NM: a group of customers, or single customer with multiple meters, located within a utility's territory, are allowed to combine meters
Subscription limit: 15% of utility's 1996 peak demand or peak demand during most recent calendar year (whichever is greater).

Application process
Simple registration process for <15kW PV
Complex registration process others

Customer & Program Costs/Benefits

Rate Structure/Bill determination

- Customer retains RECs
- Basic charges are included in bill, and cannot be credited off
- Customer is billed for the net electricity consumed
- Any excess generation will be carried over to the customer's next bill as a kilowatt-hour (kWh) credit

Compensation rate

- Credited to customer's next bill
- excess credits not used within 12 months are reset to zero

Responsibility for Costs
Utility:

- meter, metering, program administration

Customer:

- upgrade costs on the utility's equipment to accept the NM system
- application, inspection fees

Regulatory Treatment

Evaluations:
In the January 2013, and 2014 reports; the corresponding Act mandated the PSD to conduct a study on the existence and degree of cross-subsidization.

- Both reports followed the same structure and framework for the analysis
- The analysis is based on the cost-benefit analysis over a 20yr period, analyzed from a ratepayer, and system perspective:
- Costs:
  - Lost revenue (for utilities)
  - Vermont solar credit ("Adders")
  - NM administrative costs
- Benefits:
  - Avoided energy costs (incl. GHG emissions)
  - Avoided capacity costs
  - Avoided transmission, distribution costs
  - Market price suppression in energy/capacity markets
  - Potential regulatory value with renewable energy credits
- The study assessed the deployment of small and large solar (non- and tracking) and wind systems in all utilities' territories, in order to perceive the effect of their respective rate structures.
- The study concluded that: "the aggregate net cost over 20 years to non-participating ratepayers due to NM under the current policy framework is close to zero, and there may be a net benefit"
- "winter-peaking utilities, which see fewer benefits from net metered solar PV, will incur a larger share of the net cost than summer peaking utilities with lower retail rates"
  - PSD recommended that "the Board consider whether or not changes to the current program structure to allow flexibility for the program to vary by utility would better serve the state"
- It also stated, that "while rates strive to assign costs to those who cause them, this cannot be done exactly. The classic example is the comparison is the comparison of urban and rural rates"

Other information:
Adders

- Utilities must offer an 'adder' incentive for solar PV systems.
- Credit is a per kWh adder, minus the residential rate.
  - For PV <15 kW, adder is $0.20/kWh.
  - >15 kW, adder is $0.19.
- Customers will receive the adder for 10 years. after customer receives the blended rate

NM Experience

NM (Sept 26, 2014):

- 64MW (59.8MW PV, 1.9MW Wind, 2.23 MW others)
- 4,620 projects (4,416 PV, 184 Wind, 20 others)

As of 2014, six utilities had already surpassed the 4% subscription limit (increased to 15% in 2014).
Jacksonville has reached NM capacity of 14.4% peak demand.

See October 2014 Net Metering Report

Sources

1998 (30 V.S.A. 219a):
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Act 99 (2014)
http://www.leg.state.vt.us/docs/2014/bills/Passed/H-702.pdf

January 2013 Net Metering Report:
http://publicservice.vermont.gov/sites/psd/files/Topics/Renewable_Energy/Net_Metering/Act%20125%20Study%2020130115%20Final.pdf

October 2014 Net Metering Report:
http://publicservice.vermont.gov/sites/psd/files/Topics/Renewable_Energy/Net_Metering/Act%2099%20NM%20Study%20FINAL.pdf

Vermont Net Metering:
http://psb.vermont.gov/utilityindustries/electric/backgroundinfo/netmetering

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Appendix B: Tables of Net Metering Policies by Jurisdiction

Table 4: Net Metering Program Structure

		Name	Since	Capacity	Application	Aggregation	Uptake	Uptake as % of load[83]	Subscription Limit
Canada	AB	Micro-Generation	2009	1MW	Simple and Complex	Yes	4.5MW	0.03%	No
	BC	Net Metering, RS 1289	2005	50kW[84]	Simple (<27kW) and Complex	Yes	1.1MW	0.01%	No
	MB	Customer Owned Generation		50kW (single phase), 1MW (triple phase)	Simple (<10kW) and Complex	Unknown	n/a	n/a	Unknown
	NB	Net Metering	2005	100kW	Single	Yes (farmers)	n/a	n/a	0.5%
	NS	Net Metering	2005	100kW (res./comm.) 1MW (large com./ind.)	Single (<10kW) and Complex	Yes (dist. zone)	1.2MW	0.03%	No
	ON	Net Metering	2006	500kW	Single (<10kW) and Complex	No	167.3MW[85]	0.54%	1%[86]
	PEI	Net Metering	2005	100kW	Single	No	200kW[87]	0.05%	No
	QC	Net Metering	2004	50kW	Single	No	n/a	n/a	No
	SK	Net Metering	2007	100kW	Single	No	5.1MW[88]	0.12%	No
	YK	Micro-Generation	2014	5kW (on a shared transformer) 25kW (on a single transformer)	Single	No	Not yet known		
	NWT	Net Metering	2014	5kW	Single	Not addressed	202kW[89]	0.16%	20% (thermal zone)[90]
United States	AZ	Renewable Energy Standard and Tariff – Net Metering	2006	125% of Customer Load	Single	No	375MW[91] (150MW residential)	4%[10] (1.6%)	No
	ID	Net Metering	1983	25kW (res./small comm.), 100kW (ind.)	Single	Yes (limited)	2.97MW[92]	0.08%[11]	No (1 IOU) Yes (2 IOUs)
	OR	Net Metering	1999	25kW (res.), 2MW (non res.)	Single	Yes (limited)	56.6MW	0.36%	No (IOUs), Yes (Public)
	SC	Net Metering	2008	20kW (res.), 1MW (non res.)	Single	No	4.6MW	0.02%	2% of 5yr-avg. peak
	VT	Net Metering	1998	500kW (all customers), 20kW (micro-CHP), 2.2MW (military)	Single (<15kW) and Complex	Yes	63.99MW	5.2%	15% peak (IOUs, public)
	WA	Net Metering	1998	100kW	Single (<25kW) and Complex	Yes	13.89MW	0.05%	0.5% (1996 peak) – only IOUs

[83] Calculated as % of a jurisdiction's total installed capacity as of Dec 31, 2012 for Canada, and July 2014 for the US
[84] Increase to 100kW was approved on July 2014
[85] Data is representative of microFIT program (for <10kW), and accumulates projects from microFIT 1.3-1.6, 2.0, and 3.0 as of Oct 3, 2014
[86] Subscription limit has not been updated since March 2006, currently it is approximately 0.75%
[87] Value reported from four community based projects that installed 50kW turbines
[88] Estimate given 1.3MW in 2010 (target was 1.1MW) and 2017 estimate of 8MW
[89] This value excludes projects from the hydro zone (only 3 customers as of July 31, 2013)
[90] The limit for the hydro zone will be determined annually
[91] Data reported only representative of the Arizona Public Service Company
[92] Data reported only representative of Idaho Power Company (IPC)

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Table 5: Net Metering Payout Structure

		Pay out	Credit carryover cycle	Payout rate	Payout cycle	Anniversary date
Canada	AB	Yes	12 months	<150kW: retail rate, >150kW: wholesale	Annual	System installation
	BC	Yes	12 months	9.99c/kWh	Annual	System installation
	MB	Yes	12 months	Avoided cost	TBD[93]	TBD
	NB	No	12 months	No pay out	No pay out	March 31
	NS	Yes	12 months	Retail rate	Annual	System installation
	ON	No	12 months	No pay out	No pay out	System installation
	PEI	No	12 months	No pay out	No pay out	October 31 (or as decided by customer)
	QC	No	24 months	No pay out	No pay out	March 31
	SK	No	12 months	No pay out	No pay out	SaskPower will make recommendations based on system (Solar – March/April, Wind - Aug/Sept) but customer may set own date
	YK	Yes	12 months	Avoided costs • 21c/kWh (grid-interconnected customers • 30c/kWh (isolated communities)	Annual (buy all, sell all)	System Installation
	NWT	No	12 months	No pay out	No pay out	March 31
United States	AZ	Yes	12 months	Avoided cost (for on- and off-peak)	Annual	System installation
	ID	No	Idaho Power: indefinite Avista: 12 months Rocky: 12 months	No pay out	No pay out	Idaho Power: credits never expire Avista: December 31 Rocky: unclear
	OR	No	12 months	Avoided cost • Public utilities may provide payment to Oregon Heat low-income pool • IOUs provide payment to Oregon Heat low-income pool	Annual	March 31 (or as decided by customer)
	SC	No	12 months	No pay out	No pay out	SC Electric & Gas (November 1) Duke Energy (March 1)
	VT	No	12 months	No pay out	No pay out	System installation
	WA	No	12 months	No pay out	No pay out	April 30

[93] For MB, the payout cycle and anniversary date are determined in the NM agreement

Net Metering Policy Framework

July 2015

Newfoundland Labrador

Table of Contents

1.0 BACKGROUND

In its 2007 Energy Plan: Focusing our Energy, the Government of Newfoundland and Labrador committed to developing and implementing a net metering policy that would provide regulatory support for small-scale renewable energy sources.

Net metering allows utility customers with small-scale generating facilitates to generate power from renewable sources for their own consumption, and to feed power into the distribution system during periods when they generate excess power and draw power from the grid when their generation does not fully meet their needs.

This framework for a provincial net metering policy has been developed in consultation with the utilities – both Newfoundland Power (NP) and Newfoundland and Labrador Hydro (NLH). The development of the policy was supported by a jurisdictional scan of net metering best practices, which was prepared by Navigant Consulting Limited. Their final report summarized standard industry practices, primarily in Canada and the United States, which were applicable to the Newfoundland and Labrador context, and included suggested policy considerations for a provincial net metering policy framework. To further inform the development of this policy framework, stakeholders were also consulted on Navigant's report and given the opportunity to provide their input, including staff of the Board of Commissioners of Public Utilities (PUB).

2.0 POLICY OBJECTIVE

In many jurisdictions, net metering policies are often introduced as part of a broader policy to encourage the development of renewable energy sources. This is particularly the case in jurisdictions that continue to rely on fossil fuels for energy generation. Newfoundland and Labrador differs from these jurisdictions in that its system has one of the highest proportions of renewable hydraulic generation in North America. The province's current energy mix is 85 percent renewable, and this will increase to 98 percent when the Muskrat Falls Project is completed. Therefore, the primary driver for a net metering policy in Newfoundland and Labrador is not to encourage the development of renewable energy, but to provide customers with the option to offset their own energy usage through small-scale renewable generation they develop themselves.

3.0 POLICY PARAMETERS

This framework is intended to provide the utilities with the policy parameters to inform the development and implementation of their own net metering programs including the development of appropriate guidelines, connection requirements, and application processes. The following sub-sections outline the parameters of the policy.

3.1 Eligibility

Eligibility requirements for net metering include the types of renewable energy sources permitted under the policy, as well as customer classes and the size of their generation. The details of these criteria will be established by the utilities and the PUB through the regulatory process and communicated to customers in a timely manner.

3.1.1 Renewable Generation

i. Eligible energy sources under this policy are limited to small-scale renewable generation systems. These sources may include wind, solar, photovoltaic, geothermal, tidal, wave, and biomass energy.

ii. New renewable technologies will be considered by the utilities on a case-by-case basis.

3.1.2 Customer Class

i. The utilities will offer net metering to domestic and general service customers.

ii. Net metering will not be available to un-metered accounts.

3.1.3 Size of Generation

i. Generation systems shall not be sized beyond a customer's load.

ii. Customer loads, and therefore, the size of individual generation systems, will be determined based on criteria to be established by the utilities through the PUB regulatory process.

iii. Regardless of customer load requirements, individual renewable generation systems shall not exceed a maximum limit of 100kW. Given that the province includes several different electricity systems, the utilities, through the PUB regulatory process, could determine that lower customer limits on various systems may be required.

iv. In addition, technical requirements may require a limit in the aggregate amount of customer generation that can be located on isolated diesel systems. The utilities will be permitted to assess these net metering servicing requests in this context.

3.2 Program Development Requirements

The utilities will develop program details based on the policy framework, which will include establishing the rules that will be approved by the PUB. This will also include details regarding the application and approval processes and the technical requirements for connecting customer generation to the power system. These should be developed and communicated in a clear and transparent manner to potential net metering customers.

3.2.1 Guidelines, Processes and Connection Requests

i. The utilities will develop guidelines and application forms for their net metering programs, and make them publically available to inform potential net metering customers prior to implementing a net metering program.

ii. The utilities will also develop connection requirements to ensure the safety of utility workers and net metering customers and ensure the overall safe operation of equipment. These requirements will also be made publically available to inform potential net metering customers prior to implementation of any net metering program offered by the utilities.

iii. In general, in order to avail of net metering programs, customers will be required to submit an application specifying the characteristics of their service requirements and their generating equipment**.** The application process will enable the utilities to establish the technical and operating requirements for the individual installations, and to determine what electrical system additions or modifications may be required to accommodate net metering on the customer's property.

iv. The utilities will have discretion to review connection requests on an individual basis and to limit the number of net metering customers or limit the generation size in circumstances where infrastructure and/or technical constraints exist.

v. The utilities will ensure that review processes are streamlined so customers receive timely responses to their connection requests. This will also serve to minimize administrative costs for the utilities.

vi. Once connection requests are approved, customer generation systems will need to be installed within a certain timeframe, which will be determined and communicated by the utilities.

3.2.3 Generation Location

A customer's generation equipment will be located at the customer's property such that there is one metering point where the customer's net energy consumption will be metered. Meter aggregation is not permitted under this net metering policy. Only one metering point is allowed per account and property.

3.3 Cost Allocation

The rules and associated documents developed by the utilities will clearly articulate the responsibility for different costs associated with the net metering service.

3.3.1 Customer

i. The customer will be responsible for covering the cost of purchasing, installing and maintaining their renewable generating systems.

ii. The customer may be required to include a deposit as part of the net metering application, which may be used to offset the cost of any required technical studies or distribution upgrades. The utilities will carry out further investigation regarding the necessity of a deposit and, if required, will include in their program details the basis for, and conditions under which, a deposit may be required.

iii. The customer will be required to pay additional meter costs and the cost of any required permits.

iv. The customer may also be required to pay for technical reviews of the connection requests, and any distribution upgrades necessary to accommodate the connection of the customer's generator. The program details will include a description of when a detailed technical review is required and the basis for any charges to the customer for the cost of a technical review or distribution upgrades.

3.3.2 Utilities

i. The utilities will cover the costs of incremental meter readings and billing and administrative costs and will be permitted to recover these costs in the rates it charges ratepayers.

ii. The utilities will monitor uptake of net metering programs to minimize the extent that billing and administrative costs may contribute to issues of cross-subsidization. The utilities are also encouraged to look at ways they can streamline their processes.

iii. In instances where customer connection requests require distribution system upgrades, the utilities will be permitted to exercise discretion as to whether the connection request can be accommodated and whether the costs of the required upgrades should be recovered from the net metering customer.

3.4 Rates and Settlement

i. The customer`s net consumption will be billed using retail rates that are consistent with those that apply to a non-net metering customer of the same size, type and location.

ii. The customer`s net excess generation will be credited at the end of a billing period on the customer`s next bill as a kWh credit.

iii. Accounts will be monitored annually to identify any accounts which are developing a significant credit over a 12-month period.

iv. On the customer`s Annual Review Date, net excess generation will be settled with a cash payment or bill credit. Whether it is a cash payment or bill credit will be proposed by the utilities, subject to PUB approval, and then communicated to customers in their program guidelines. The customer will be compensated for the net excess generation at the retail rates that are used to determine the bill for the customer's net consumption. This retail rate will factor in existing subsidies, and should represent the effective rate at which the customer is billed. Following implementation, government, in consultation with the utilities and the PUB, will monitor and review the net metering program.

3.5 Subscription Limits

A provincial subscription limit shall be set at 5MW for all net metering customers' generating facilities that are a part of the net metering program. Government, in consultation with the utilities and the PUB, will monitor the response to net metering and may adjust the overall capacity limit in the future if the level of uptake warrants it.

3.6 Cross-Subsidization

The utilities will quantify the rate impact and the risk of cross subsidization in its program applications to the PUB. Once implemented, and on an ongoing basis, the utilities will monitor their net metering programs regarding the extent of any cross-subsidization.

3.7 Associated Credits

Net metering customers will retain the value of any renewable energy credits (RECs) or GHG-related credits available from the sale of such credits resulting from their small-scale renewable energy generation.

3.8 Regulatory Treatment

As both NP and NLH are regulated by the PUB, and any net metering programs developed will be a part of the appropriate rate structure, the utilities will require approval from the PUB prior to implementation of any net metering program.

3.9 Impact on Other Programs and Policies

Maximum Monthly Charge

The utilities electricity rates for General Service customers include a Maximum Monthly Charge. The purpose of this charge is to limit the extent to which low load factor customers pay for demand related costs. Net metering may reduce a customer's monthly net energy requirements without materially impacting their monthly demand requirements. To ensure reasonable recovery of demand related costs from net metering customers, the Maximum Monthly Charge will not be available to customers served under a utility's net metering program.

Biogas Electricity Generation Pilot Project

A net metering customer cannot also participate in the Biogas Electricity Generation Pilot Project.

4.0 ROLES AND RESPONSIBILITIES

Government of Newfoundland and Labrador (Department of Natural Resources)

The Government of Newfoundland and Labrador is responsible for providing the policy, legislative and regulatory framework under which net metering programs may be developed by the utilities. GNL will work with NP and NLH to monitor and evaluate the net metering programs made available to customers.

Newfoundland Power

NP is responsible for:

- developing and implementing a net metering program including the development of appropriate guidelines, connection requirements, and application processes, as well as communicating program components to potential net metering customers in a timely manner;

- developing rate structures;
- applying to the PUB for approval;
- covering the costs of billing and administration of their program (with incremental costs recovered in rates); and
- monitoring and evaluating their net metering program.

Newfoundland and Labrador Hydro
NLH is responsible for:

- developing and implementing a net metering program including the development of appropriate guidelines, connection requirements, and application processes, as well as communicating program components to potential net metering customers in a timely manner;
- developing rate structures;
- applying to the PUB for approval;
- covering the costs of billing and administration of their program (with incremental costs recovered in rates); and
- monitoring and evaluating their net metering program.

Board of Commissioners of Public Utilities
As regulator of the utilities, the PUB is responsible for reviewing the utilities' proposals and approving net metering programs to ensure the rules developed by the utilities are consistent with the *Public Utilities Act* and the *Electrical Power Control Act.*

Net Metering Customers
Under the net metering programs offered by the utilities, potential net metering customers are responsible for:

- covering the cost of purchasing, installing and maintaining their renewable generating systems;
- conducting their own financial analysis to determine the costs and benefits of net metering for their own situation;
- any costs assigned under the net metering program such as covering additional meter costs and the cost of any required permits; and,
- ensuring that they adhere to the utilities' connection requirements and provide all required information necessary to process applications under their net metering programs.

5.0 MONITORING AND EVALUATION

The Department of Natural Resources will continue to work closely with NP and NLH to monitor the implementation of the net metering programs offered by the utilities.

6.0 DEFINITIONS

Annual Review Date

Represents the date that marks a customer's annual participation in the net metering program and the date on which any credits from excess generation are paid out. This date will be determined by the net metering customer, in conjunction with the utilities.

Biogas Electricity Generation Pilot Project

Biogas is a combustible gas created by landfills and farms through the anaerobic (i.e. without oxygen) decomposition of organic material. Newfoundland and Labrador's Biogas Electricity Generation Pilot Program was established in 2014/15 to encourage the development of biogas power generation and generate electricity for the system.

Cross Subsidization

An issue arising when transmission and distribution costs, and other program related costs, attributable to net metering customers are transferred to non-net metering customers.

Maximum Monthly Charge

The Maximum Monthly Charge is available to General Service customers with demands of 10kW or greater. The purpose of this charge is to limit the extent to which low load factor customers who use a relatively low amount of energy relative to their peak demand, pay for demand related costs. This limit reflects the likelihood that low load factor customers will have a relatively low demand during system peaks and, therefore, should not be subject to the full demand charge.

Meter Aggregation

Involves allowing a single customer with multiple meters in a service territory to consolidate meters so that one source of renewable generation could be used to offset energy usage at different locations owned by the same customer.

Net Metering

Net metering allows utility customers with small-scale generating facilitates to generate power from renewable sources for their own consumption, and to feed power into the distribution system during periods when they generate excess power and draw power from the grid when their generation does not fully meet their needs.

Renewable energy credits (RECs)

Renewable energy credits are non-tangible, tradable commodities that represent the environmental and other non-power attributes of one megawatt-hour of renewable electricity generation.

Subscription Limit

Subscription limits place an overall limit (or cap) on the amount of generation capacity which can be installed under the net metering policy as a whole.

NEWFOUNDLAND POWER INC.

SCHEDULE

OF

RATES, RULES AND REGULATIONS

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NEWFOUNDLAND POWER INC.

RATES, RULES AND REGULATIONS

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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.

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(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.

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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.

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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.

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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.

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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.

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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.

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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.

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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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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:

$$\frac{B + C}{D}$$

Where:

B = 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.

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:

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

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 streetlighting rates are as follows:

	Fixture Size (watts)				
	100	150	175	250	400
Mercury Vapour	-	-	840	1,189	1,869
High Pressure Sodium	454	714	-	1,260	1,953

4. On December 31, 2015, 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 interim wholesale rate change, effective July 1, 2015, 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 on an interim basis by Hydro effective July 1, 2015.

   This clause will be revised as required when the Company's rates are changed to reflect the flow-through of final changes to Hydro's wholesale rate.

   The methodology to calculate the RSA adjustment at December 31, 2015 is as follows:

Calculation of increase in Revenue:	
2015 Revenue with Flow-through (Q)	$ -
2015 Revenue without Flow-through (R)	$ -
Increase in Revenue (S = Q – R)	$ -
Calculation of increase in Purchased Power Expense:	
2015 Purchased Power Expense with Hydro Increase (T)	$ -
2015 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, 2015.
   R = Normalized revenue from base rates determined based on rates effective July 1, 2013.
   T = Normalized purchased power expense from Hydro's wholesale rate effective July 1, 2015 (not including RSP rate).
   U = Normalized purchased power expense determined based on Hydro's wholesale rate effective January 1, 2007 (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 (other than the energy charge in the "Maximum Monthly Charge" in classifications having a demand charge) 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.

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 .... $15.99 per month
Exceeding 200 Amp Service .... $20.99 per month

Energy Charge:
All kilowatt-hours .... @9.719¢ per kWh

Minimum Monthly Charge:
Not Exceeding 200 Amp Service .... $15.99 per month
Exceeding 200 Amp Service .... $20.99 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 ....$17.14 per month
Single Phase ....$21.14 per month
Three phase ....$27.14 per month

Demand Charge:
$9.19 per kW of billing demand in the months of December, January, February and March and $6.69 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 .... @ 9.622¢ per kWh
All excess kilowatt-hours .... @ 6.848¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 19.002 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 .... $17.14 per month
Single Phase .... $21.14 per month
Three Phase .... $33.14 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: .... $49.44 per month

Demand Charge:
$7.77 per kVA of billing demand in the months of December, January, February and March and $5.27 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 .... @ 7.995¢ per kWh
All excess kilowatt-hours .... @ 6.150¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 19.002 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: .... $86.15 per month

Demand Charge:
$7.47 per kVA of billing demand in the months of December, January, February and March and $4.97 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 .... @ 7.666¢ per kWh
All excess kilowatt-hours .... @ 6.082¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 19.002 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)

High Pressure Sodium	**Sentinel/Standard**	**Post Top**
100W (8,600 lumens)	$16.78	$18.15
150W (14,400 lumens)	20.51	-
250W (23,200 lumens)	28.19	-
400W (45,000 lumens)	38.41	-

Special poles used exclusively for lighting service**

Wood	$6.27
30' Concrete or Metal, direct buried	8.96
45' Concrete or Metal, direct buried	14.67
25' Concrete or Metal, Post Top, direct buried	6.67

Underground Wiring (per run)**

All sizes and types of fixtures	$15.30

** 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 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, #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 un-metered 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, #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 credited 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, #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, #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.