NET METERING STANDARD INDUSTRY PRACTICES STUDY

Prepared for:

The Department of Natural Resources,
Government of Newfoundland & Labrador

October 31, 2014

Navigant Consulting Ltd.
Bay Adelaide Centre
333 Bay Street, Suite 1250
Toronto, ON M5H 2R2
416 777-2440
416 777 2441 (fax)
www.navigant.com

This page intentionally left blank.

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*

[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_

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".

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.

[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.

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.

NAVIGANT

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.

Table of Contents

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.

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

[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_

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

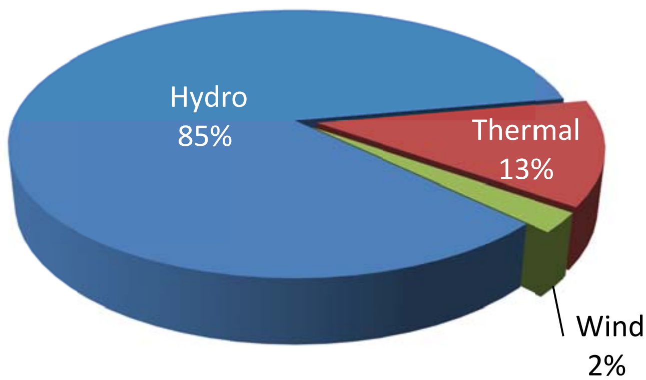


Figure 2 illustrates the Newfoundland and Labrador transmission system.

Figure 2: Newfoundland and Labrador Transmission

Source: NL Hydro System Planning Department 2014.

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.

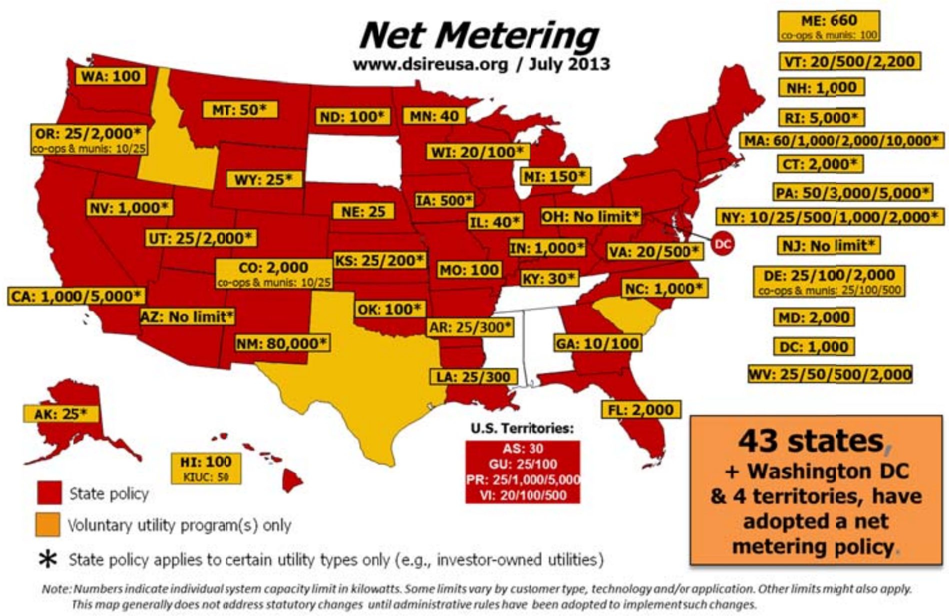
---

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

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).

---

[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.

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.

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.

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.

"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

[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.

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

[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/

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

---

[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

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

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).

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

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

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.

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.

[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 .

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

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

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.

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

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.

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

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

---

[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

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

---

[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

NAVIGANT

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

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

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

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.

[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.

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.

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.

---

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,

- 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/)

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.

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.

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.

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.

NAVIGANT

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

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

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

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"*
  - 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:
  - In 2008, the aggregate capacity of the Net Metering and Embedded Generation programs was capped at 21MW
  - 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

Genera Informationl:
http://www.nbpower.com/html/en/save_energy/renewable_projects/net_metering/net_metering.html

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)
http://www2.gnb.ca/content/dam/gnb/Departments/en/pdf/Publications/2002MDCFinal-Report.pdf

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

Laree Industrial Renewable Energy Purchase:
http://www.electionsnb.ca/content/gnb/en/departments/energy/industrial.html

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

Genera Information:
https://www.nspower.ca/en/home/for-my-home/make-your-own-energy/enhanced-net-metering/default.aspx

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

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:
http://www.maritimeelectric.com/about_us/regulation/reg_irac_regulations_det.aspx?id=165&pagenumber=36

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

NM Jurisdictional Review

Jurisdiction

Quebec

Hydro-Québec - Metering Rate Option

Drivers for NM

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:

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

Program Design/Framework

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.

Customer & Program Costs/Benefits

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

Regulatory Treatment

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

NM Experience

N/A

Sources

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

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
News release:
http://www.gov.sk.ca/news?newsId=98743f57-adf3-4ba5-8872-9a05c0fa9169

Application:
http://www.saskpower.com/wp-content/uploads/net_metering_application.pdf

Go Green Fund Program Review:
http://www.environment.gov.sk.ca/adx/aspx/adxGetMedia.aspx?DocID=1606,1601,104,81,1,Documents&MediaID=298e9b6a-0994-48ff-a887-ed5190ddc61f&Filename=Go+Green+Fund+Review.pdf

Inquiry into SK's Energy needs final report:
http://www.legassembly.sk.ca/legislative-business/legislative-committees/crown-and-central-agencies/100405report-cca-09.pdf

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

NM Jurisdictional Review

<table>
<tr><th>Jurisdiction</th><th>Drivers for NM</th><th>Program Design/Framework</th><th>Customer & Program Costs/Benefits</th><th>Regulatory Treatment</th><th>NM Experience</th><th>Sources</th></tr>
<tr>
<td>Yukon

Micro-Generation Policy and Micro-Generation Production Incentive Program

(This program is the 'net metering' portion of the Micro-Generation Policy)</td>
<td>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:
<table>
<tr><th>Dec 2012</th><th>MW</th><th>%</th></tr>
<tr><td>Diesel</td><td>55</td><td>37%</td></tr>
<tr><td>Hydro</td><td>94</td><td>62%</td></tr>
<tr><td>Wind</td><td>0.8</td><td>1%</td></tr>
<tr><td>Total</td><td>150</td><td>100%</td></tr>
</table>

YEC generates 98% of electricity from hydro.</td>
<td>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

<u>Meter aggregation:</u> No
<u>Subscription limit</u>: 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</td>
<td>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
o 21c/kWh for grid-interconnected customers
o 30c/kWh for isolated communities (reflective of diesel gens)
o (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
<u>Customer Costs</u>
• interconnection costs and any potential transformer upgrade requirements

<u>Utility Cost</u>:
• Utilities will be limited to paying for and maintain the meter</td>
<td>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
<u>Solar Energy Pilot:</u>
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.</td>
<td>N/A</td>
<td>Government's Energy Strategy (2009):
http://www.energy.gov.yk.ca/pdf/energy_strategy.pdf

Micro-Generation Policy:
http://www.energy.gov.yk.ca/pdf/20131023_micro_generation_policy.pdf

Solar Pilot Evaluation:
http://emrlibrary.gov.yk.ca/energy/yukon_government_solar_energy_pilot_2014.pdf

Avoided costs:
http://www.atcoelectricyukon.com/Documents/Regulatory/2013-05-27%20YECL%202013-2015%20GRA%20Part%202.pdf

Draft Net Metering Policy:
http://www.energy.gov.yk.ca/pdf/EMR_Net_Metering_Policy_Draft.pdf

2009 paper
http://www.esc.gov.yk.ca/pdf/ipp_net_metering_discussion_paper_nov2009.pdf</td>
</tr>
</table>

NM Jurisdictional Review

<table>
<tr><th>Jurisdiction</th><th>Drivers for NM</th><th>Program Design/Framework</th><th>Customer & Program Costs/Benefits</th><th>Regulatory Treatment</th><th>NM Experience</th><th>Sources</th></tr>
<tr>
<td>Nunavut

(NM - policy still under development by Nunavut Government)</td>
<td>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>
</td>
<td>Legislation:
Qullig Energy is subject to the Qullig Energy Act, and the Utility Rates Review Council Act.</td>
<td></td>
<td><u>2012/2013 Annual Report:</u>
• "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"

<u>2014/15 General Rate Application:</u>
• "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.</td>
<td></td>
<td>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</td>
</tr>
</table>

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)
  - o The cumulative NTPC (thermal zone) average load was 13MW, such that 2.6MW was the limit.
  - o (March 31, 2014) 202kW (all PV) of NM capacity, which is 1.6% of the average load
  - o 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

Net Metering Overview:
https://www.ntpc.com/docs/default-source/default-document-library/net-metering.pdf?sfvrsn=0

Application Process:
https://www.ntpc.com/docs/default-source/default-document-library/application-process-flow-chart.pdf?sfvrsn=0

Application Form:
https://www.ntpc.com/docs/default-source/default-document-library/net-metering-application.pdf?sfvrsn=0

Interconnection Guidelines:
https://www.ntpc.com/docs/default-source/default-document-library/technical-interconnection-guideline.pdf?sfvrsn=0

PUB Approval of NM:
http://www.nwtpublicutilitiesboard.ca/pdf/1-2014%20DECISION%20NTPC%20NUL%202013%20Net%20Metering%20Applications.pdf

NTPC 2013 Annual Report
http://www.ntpc.com/docs/default-source/Reports/ntpc_annual_report_2013_web.pdf?sfvrsn=0

Solar Energy Strategy 2012-2017
http://www.nwtclimatechange.ca/sites/default/files/Solar_Energy_Strategy_2012-2017_0.pdf

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

Arizona Administrative Code, Net Metering
http://www.azsos.gov/public_services/Title_14/14-02.htm#ARTICLE_23

ACC, Final Order Re: APS 2013 Application
http://www.dsireusa.org/documents/Incentives/AZ%20Final%20Order%2074202.pdf

APS Net Metering schedule:
http://www.aps.com/library/rates/epr-6.pdf

2013 RES Compliance Report:
http://www.aps.com/library/renewables/RES2013ComplianceReport.pdf

APS Cost Shift Application to ACC:
http://images.edocket.azcc.gov/docketpdf/0000146792.pdf

Energy Policy Innovation Council Report:
http://energypolicy.asu.edu/wp-content/uploads/2013/12/APS-Net-Metering-Brief-Sheet-Draft-_-Final_updated-Dec-2013.pdf

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
http://app.leg.wa.gov/RCW/default.aspx?cite=80.60

Utilities and Transportation Commission (UTC) – Net Metering
http://www.utc.wa.gov/regulatedIndustries/utilities/energy/Pages/netMetering.aspx

1999 UTC Report:
http://www.utc.wa.gov/regulatedIndustries/utilities/Documents/netmeteringreport.pdf

Avista Schedule:
http://www.avistautilities.com/services/energypricing/wa/elect/Documents/WA_063.pdf

Pacific Corp Schedule:
https://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Rates_Regulation/Washington/Approved_Tariffs/Rate_Schedules/Net_Metering_Service.pdf

Pudget Sound Schedule:
http://pse.com/aboutpse/Rates/Documents/elec_sch_150.pdf

(July 30, 2014) UTC – Regulation of third party owners of net metering facilities:
http://www.wutc.wa.gov/rms2.nsf/0/779154169526DB0688257D25006E653A/$file/UE-112133%2BInterpretive%2BStatement%2B-%2BJuly%2B30%2B2014.pdf

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

IPUC Order 29094 and Order 28951 (2002):

- 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)

Meter aggregation:

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

Subscription limit:

- 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

Utility:

- Meter, metering, program administration

Customer:

- 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:

Application IPC-E-12-27:

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:

Billing System

- 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.

System Reliability

- 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

Net Metering legislation:
http://app.leg.wa.gov/RCW/default.aspx?cite=80.60

UTC Net Metering page:
http://www.utc.wa.gov/regulatedIndustries/utilities/energy/Pages/netMetering.aspx

Tariff - IPC:
https://www.idahopower.com/AboutUs/RatesRegulatory/Tariffs/tariffPDF.cfm?id=198

Tariff - Avista:
http://www.avistautilities.com/services/energypricing/id/elect/Documents/ID_063.pdf

Tariff - Rocky Mountain Power:
https://www.rockymountainpower.net/content/dam/rocky_mountain_power/doc/Environment/Environmental_Concerns/Net_Metering_Service.pdf

IPC 2012 Application website:
http://www.puc.idaho.gov/fileroom/cases/summary/IPCE1227.html

IPC 2012 Application
http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1227/20121130APPLICATION.PDF

IPUC Final Order (July 3, 2013)
http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1227/ordnotc/20130703FINAL_ORDER_NO_32846.PDF

IPUC Final Order Press Release:
http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1227/staff/20130703PRESS%20RELEASE.PDF

IPC 2013 NM Report:
http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1227/company/20140228ANNUAL%20NET%20METERING%20REPORT.PDF

NAVIGANT

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.
  - 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.
  - 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

Pacific Unused kWh Report 2013:
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

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

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):
http://www.leg.state.vt.us/statutes/fullsection.cfm?Title=30&Chapter=005&Section=00219a

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

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)

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