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May 18, 2017

B.C. Sustainable Energy Association
c/o William J. Andrews, Barrister & Solicitor
1958 Parkside Lane
North Vancouver, B.C.
V7G 1X5

Attention: Mr. William J. Andrews

Dear Mr. Andrews:

Re: FortisBC Inc. (FBC)

Project No. 3698896

2016 Long Term Electric Resource Plan (LTERP) and Long Term Demand Side Management Plan (LT DSM Plan)

Response to the B.C. Sustainable Energy Association and Sierra Club of British Columbia (BCSEA) Information Request (IR) No. 2

On November 30, 2016, FBC filed the Application referenced above. In accordance with the British Columbia Utilities Commission Order G-197-16 setting out the Regulatory Timetable for the review of the Application, FBC respectfully submits the attached response to BCSEA IR No. 2.

If further information is required, please contact Joyce Martin at 250-368-0319.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

VOLUME 2 – LONG-TERM DEMAND-SIDE MANAGEMENT PLAN

23.0 Topic: Long Term DSM Plan

Reference: Exhibit B-4, FBC Response to BCSEA-SCBC IR 1.15.1

In its response to BCSEA-SCBC IR 1.15.1, FBC explains that average line losses are used in calculating the cost-effectiveness of DSM. BCSEA-SCBC understands that geographically-specific line loss rates are not used in determining DSM cost-effectiveness. However, FBC may not have understood the intent of this question. Presumably, line losses are higher at times of peak demand than they are on average across the full range of loads.

23.1 Please explain whether FBC agrees that line losses are greater at times of peak demand than they are at times of average demand.

Response:

Agreed.

23.2 Does FBC's estimate of average line losses refer both to average geographically, as explained in its response to BCSEA-SCBC IR 1.15.1, and average relative to the range of line losses experienced at different levels of demand?

Response:

FBC's estimate of average line losses refers to the losses at average demand across the FBC system.

23.3 Please confirm that FBC's estimate of line loss rates is based on line losses at average demand. If not confirmed, please explain.

Response:

Yes, FBC's estimate of line losses is based on line losses at average demand.

23.4 Does FBC agree that DSM reduces the requirement for energy and capacity at the margin?

Response:

DSM programs reduce energy consumption over all hours of the year and all load conditions, not just the peak hours of the year. Therefore, while it is correct that in general DSM reduces the requirement for energy and capacity at the margin, it is incorrect to assume that all DSM savings benefit the system at the peak marginal loss rate. In addition, certain DSM measures, such as air source heat pumps, do not reliably deliver savings under the cold weather conditions experienced at the time of FBC's annual system peak. FBC believes that the appropriate level of losses to use in DSM program evaluation is average line losses.

24.0 Topic: Long Term DSM Plan

Reference: Exhibit B-2, FBC Response to BCSEA-SCBC IR 1.16.4

BCSEA-SCBC IR 1.16.4 asks FBC to "describe and provide anticipated costs and savings values for a scenario that includes all the cost-effective DSM from an LRMC perspective."

FBC's response is: "Please refer to the response to BCUC IR 1.33.1 for a hypothetical scenario where DSM activities offset 100 percent of load growth, which is approximately equivalent to the total interim estimate of market potential." [underline added]

24.1 Is it a coincidence that "100 percent of load growth" is approximately equivalent to the "total interim estimate of market potential"? If not, please explain the linkage.

Response:

Confirmed, it is a coincidence that "100 percent of load growth" is approximately equivalent to the "total interim estimate of market potential".

25.0 Topic: Long Term DSM Plan

Reference: Exhibit B-2, FBC Response to BCUC IR 1.23.2.1

In its response to BCUC IR 1.23.2.1, FBC states that:

"Targeted regional [DSM] offers introduce disparate incentive offers, which are inequitable to customers outside of the target region.

FBC considers DSM savings to be reliable but non-firm resources, and thus cannot be counted on to defer network system reinforcements that are predicated on peak load requirements."

25.1 Is it FBC's position that providing "disparate incentive offers" to encourage DSM participation that would reduce the overall cost of service would violate a policy or regulation?

Response:

FBC's understanding is that providing DSM measures on a regional basis would not violate any known policy or regulation. However, as stated in FBC's response to BCUC IR 2.81, the Company believes that it is important to maintain equity in its DSM programs for qualifying customers to encourage widespread participation regardless of a customer's location in the FBC service area. FBC believes that offering different incentives to customers in the same rate class, based on their location in the service area, is inequitable.

Regardless of whether targeted regional DSM is inequitable or not, DSM is not a reliable resource for the purposes of offsetting supply side investment as discussed in the responses to BCOAPO IR 2.58.2.1 and BCSEA IR 2.25.2.

25.1.1 If the answer is yes, please explain, and cite the policy(ies) or regulation[s].

Response:

Please refer to the response to BCSEA IR 2.25.1.

25.2 Please provide evidence to support the assertion that "DSM savings cannot be counted on to defer network system reinforcements."

Response:

FBC system planning is based on the actual load growth trajectory for specific lines and substation equipment. To the extent that existing DSM measures have reduced historical peak loads, the inherent peak load reduction does broadly impact load forecasting and the required in-service date of network reinforcements. On a forward looking basis, the DSM savings in any one location can be greater or less than anticipated (depending on DSM uptake rates), meaning that the impact of future DSM measures on forecast peak load for specific infrastructure is uncertain. Once a planning criteria threshold has been crossed, an upgrade is planned for the infrastructure in question in order to meet mandatory service quality and reliability standard requirements.

A specific example of the non-dependability of DSM measures with respect to system operations and planning is air source heat-pumps. While these devices offer significantly greater performance and energy savings as compared to electric resistance heating for most of the year, at temperatures below approximately -10°C to -20°C, an air source heat pump (ASHP) relies almost entirely on backup heating (typically electric resistance heating)[1]. Since FBC is a winter peaking utility, this switchover to high-demand backup heat occurs at the worst possible time and contributes to increasing the system peak load and the need for network system reinforcements.

Please also refer to the response to BCOAPO IR 2.58.2.1.

25.3 To FBC's knowledge, are any other jurisdictions in North America considering or using DSM as a tool to "defer network system reinforcements"?

Response:

E source, a subscription-based research firm focusing on how consumers use energy and how utilities can best serve them, provided the summary contained in Attachment 25.3 of targeted DSM programs as "non-wires" solutions to defer network system reinforcements. The E source survey lists various DSM programs in about ten US jurisdictions, including targeted energy-

[1] Electric Heat Lock Out on Heat Pumps – Washington State University, Extension Energy Program (http://www.energy.wsu.edu/documents/AHT_Electric%20Heat%20Lock%20Out%20on%20Heat%20Pumps%20%282%29.pdf)

1 efficiency and demand-response (typically offsetting summer peaks) as well as optimal locations
2 for the deployment of distributed resources.

3

26.0 Topic: Long Term DSM Plan

Reference: Exhibit B-4, FBC Response to BCSEA-SCBC IR 1.18.9

In its response, FBC states that "FBC considers itself to be long on capacity over the planning horizon, as is illustrated in LTERP 20 Figure 8-4: Capacity-Load Resource Balance after DSM at page 102 of the LTERP (see Exhibit 21 B-1, p. 102), and thus there is no requirement for capacity-focused DSM measures."

26.1 Are there any regions in FBC's distribution service territory where system reinforcements are planned or contemplated to address capacity constraints?

Response:

FBC has two annual capital programs that address localized distribution capacity throughout its service territory. The Unplanned Growth and Small Growth programs include unforeseen and other minor upgrades, and together account for approximately $1.6 million annually.

26.1.1 If yes, please list the projects, when they need to be completed to meet capacity requirements, and the estimated cost for each.

Response:

FBC is unable to provide a list of specific projects. Unplanned Growth typically deals with emergent capacity issues that are identified shortly before or during the budget year. For Small Growth projects, which are estimated at no greater than $0.5 million individually, studies are still being completed to identify areas of the system with the most urgent needs for capacity increases.

27.0 Topic: Long Term DSM Plan

Reference: Exhibit B-4, FBC Response to BCSEA-SCBC IR 1.20.5

In its response, FBC states that "No early retirement measures were explored because they are more costly than replace on burnout measures."

27.1 Would the savings for early retirement measures be greater than for replace on burnout measures? Please explain.

Response:

In some cases, the savings for early retirement will be greater than for replace on burnout measures, at least for the remaining life of the existing appliance.

As an example, consider the replacement of an existing 70 percent efficient natural gas furnace with a heat pump. In the case of early replacement, the increase in efficiency is the difference between the heat pump and the still-functional existing furnace. However, in the case of replacement on burnout, because the furnace must be replaced with a furnace having a minimum efficiency of 92 percent by government regulation, the gain in efficiency is considered to be only the difference between the newly installed heat pump and the minimum-efficiency furnace.

27.2 If the answer to the previous question is yes, how would FBC know that early retirement measures would not be worth pursuing unless it does the analysis?

Response:

FBC will consider this replacement type as part of the BC CPR additional scope services work to estimate electrification (fuel switching) potential.

28.0 Topic: Long Term DSM Plan

Reference: Exhibit B-4, FBC Response to BCSEA-SCBC IR 1.20.8.1

In its response, FBC states "Please refer to the response to BCSEA IR 1.20.8" in which it explains that "…the incremental savings from the increased cooling efficiency are minimal…."

28.1 Regardless of the level of cooling savings, in analyzing the fuel-switching measure did FBC assume that the existing cooling unit would remain operational when the furnace "burned out" or did it assume that the both the cooling unit and furnace would have been replaced in the scenario that it compared the heat pump fuel switch against?

Response:

FBC assumes that if a residential customer replaced an existing natural gas furnace and cooling unit with an ASHP, that customer would remove both the natural gas furnace and the cooling unit.

The ASHP would then act as both the heating and cooling unit.

28.2 If FBC assumed that the existing cooling unit was not replaced, explain why it made that assumption.

Response:

Please refer to the response to BCSEA IR 2.28.1.

28.3 If FBC assumed that the existing cooling unit was replaced along with the furnace, were the costs of the cooling unit included in the analysis?

Response:

The ASHP unit provides both heating and cooling for the same cost, and the cost of the ASHP unit has been included.

VOLUME 1 – LONG TERM ELECTRICITY RESOURCE PLAN

29.0 Topic: Low-carbon electrification

Reference: Exhibit B-4, FBC Response to BCSEA-SCBC IR 1.20.9; *Clean Energy Act*, ss.18(1), (2) and (3); OIC 101/207, amendment of the Greenhouse Gas Reduction (Clean Energy) Regulation, B.C. Reg 102/2012.

FBC was asked about opportunities for low carbon fuel switching from non-transportation fossil fuels other than natural gas to electricity within FBC's service territory. FBC responds:

"FBC considers fuel switching to be load building, and as such is not within the scope of the LT DSM Plan."

Clean Energy Act, subsections18(1), (2) and (3) state:

Greenhouse gas reduction

18 (1) In this section, **"prescribed undertaking"** means a project, program, contract or expenditure that is in a class of projects, programs, contracts or expenditures prescribed for the purpose of reducing greenhouse gas emissions in British Columbia.

(2) In setting rates under the *Utilities Commission Act* for a public utility carrying out a prescribed undertaking, the commission must set rates that allow the public utility to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to the prescribed undertaking.

(3) The commission must not exercise a power under the *Utilities Commission Act* in a way that would directly or indirectly prevent a public utility referred to in subsection (2) from carrying out a prescribed undertaking.

On March 1, 2017, the Lieutenant Governor in Council approved OIC 101/2017, amending the Greenhouse Gas Reduction (Clean Energy) Regulation, B.C. Reg 102/2012. OIC 101/2017 defines prescribed undertakings for reducing greenhouse gas emissions in British Columbia that can be carried out by a public utility. Section 18 of the CEA requires the Commission to allow the public utility to recover in rates its costs incurred with respect to the prescribed undertaking.

29.1 For convenience, please file a copy of OIC 101/2017.

Response:

Please refer to Attachment 29.1.

29.2 In FBC's view, does OIC 101/2017 apply to FBC (electric)? If not, why not?

Response:

Yes, as a public utility in British Columbia, FBC is permitted to pursue the prescribed undertakings established by OIC 101/2017.

29.3 Does FBC agree that the amended subsection 4(3) of the Regulation prescribes a class of undertaking that could include an FBC low-carbon fuel switching electrification program, where pursuant to s.4(4) the program was "cost-effective" as defined in s.4(1)? If not, why not?

Response:

Yes. Subsection 4(3) of the amended Greenhouse Gas Reduction (Clean Energy) Regulation (*GGRR*) refers to programs, projects or expenditures to encourage or enable the use of electricity instead of other sources of energy that produce more greenhouse gas emissions. FBC agrees that a low-carbon fuel-switching electrification program could meet the criteria in subsection 4(3).

29.3.1 Does FBC agree that in principle FBC would be entitled to recover in rates its costs of such a program pursuant to CEA s.18? If not, why not?

Response:

Yes. Subsection 18(2) of the *CEA*, which is included in the preamble, provides that the costs incurred with respect to prescribed undertakings are recoverable in rates.

29.4 Does FBC agree that in principle, i.e., apart from timing considerations, low-carbon fuel switching electrification measures are appropriate for inclusion in its long-term electricity resource plan under s.44.2 of the UCA?

Response:

Section 44.2 of the *UCA*, which is referenced in the question, refers to an expenditure schedule and not a long-term resource plan; s.44.1 is the section that refers to long-term resource and conservation planning.

FBC agrees in principle that low-carbon fuel switching electrification measures are appropriate for inclusion in long term electricity resource plans under s. 44.1 of the *UCA* if they are expected to materially impact the forecast load requirements. In Section 4 of the LTERP, FBC discusses several load drivers, which include fuel switching and electric vehicles. In Section 9.3.6 of the LTERP, FBC discusses portfolios based on higher or lower loads than the reference case forecast and Section 9.3.6.2 discusses contingency plans relating to potential load scenarios.

29.5 On the assumption that FBC low-carbon fuel switching electrification measures would not be demand-side measures as defined in the CEA, does FBC agree that OIC 101/2017 nevertheless provides an opportunity for FBC to pursue low-carbon electrification, a limited form of load building? If not, why not?

Response:

Yes. Please refer to the response to BCSEA IR 2.29.3.1.

29.6 Does FBC intend to examine and develop low-carbon electrification measures and propose them if they would be cost-effective? If so, please describe the timeframe. If not, why not?

Response:

Yes. Please refer to the response to BCUC IR 2.71.1 for a discussion of the timeframe.

29.7 Please provide FBC's understanding of the cost-effectiveness methodology in the new section 4 the GHG Reduction (Clean Energy) Regulation and how it would apply to low-carbon electrification measures by FBC.

Response:

The cost-effectiveness methodology is set out in four defined terms in section 4(1) of the *GGRR* (as amended). The relevant definitions are "benefit", "cost", "cost-effective" and "specified year". The methodology involves comparing the present value of benefits and costs, both as defined by the Regulation, between the commencement of the undertaking and the specified year (which means a year designated by the Minister, or if none has been specified, 2030). If the present value of benefits are reasonably expected to exceed the present value of costs, then the undertaking is cost-effective.

29.8 Does FBC agree that the cost-effectiveness methodology for low-carbon electrification measures under section 4 of the GHG Reduction (Clean Energy) Regulation is significantly different that the cost-effectiveness methodology for demand-side measures set out in the DSM Regulation?

Response:

Yes, the cost-effectiveness methodology set out in OIC 101/2017 (amending the *GGRR*) is significantly different than the cost-effectiveness methodology for demand-side measures set out in the DSM Regulation.

In the DSM Regulation, the cost-effectiveness of demand-side measures uses the governing Total Resource Cost Test (TRC) or modified Total Resource Cost Test (mTRC), which considers the costs and benefits of a measure for both the measure participants and the utility.

The cost-effectiveness methodology set out in the new section 4(1) of the *GGRR* (as amended) measures the cost and benefits of electrification on the utility, but does not include costs and benefits for the non-utility participants. Specifically, the benefits are defined as "all revenues the public utility reasonably expects to earn as a result of implementing the [electrification] undertaking less revenues that would have been earned from the supply of undertaking electricity to export markets". Cost effectiveness is defined as the present value of the benefits divided by the utility costs to implement the undertaking.

"A more comprehensive review of fuel switching potential will be undertaken as part of the BC CPR additional scope services now underway." [Exhibit B-4, BCSEA-SCBC IR 21.2, pdf p.51]

29.9 Will the more comprehensive review of fuel switching potential that will be undertaken as part of the BC CPR additional scope services be adequate and sufficient for FBC to develop and implement (if cost-effective) low-carbon electrification measures under OIC 101/2017? If additional analysis will be required, how will FBC obtain it?

Response:

FBC became aware of the content of OIC 101/2017 on March 2, 2017, and has had limited opportunity to evaluate the potential for electrification (fuel switching) that may now be encompassed by the *GGRR*.

The scope of the additional services to be provided in the second phase of the BC CPR pre-dated the publication of OIC 101/2017, however FBC believes the additional scope services will help inform FBC's evaluation of fuel-switching potential. The Company explains its expected process regarding fuel switching initiatives in its response to BCUC IR 2.71.1. If additional analysis is required, it will be undertaken as support for an application with respect to section 18 of the *CEA*.

29.10 Noting that FBC made an extensive list of information requests to BC Hydro regarding low-carbon electrification potential in the Commission's proceeding regarding BC Hydro's F2017-F2019 Revenue Requirements Application [Exhibit C8-3 in that proceeding], does FBC intend to work together with BC Hydro in developing low-carbon electrification measures that are suitable for both utilities' service territories?

Response:

FBC believes that working with BC Hydro on the development of low-carbon electrification measures that are suitable for both utilities' service territories is a worthwhile objective. Over time this cooperation could become similar to the cooperation that exists among utilities in B.C. with respect to DSM initiatives. As discussed in Section 2.3.2 of the LTERP, FBC is already working with BC Hydro and other organizations on EV charging infrastructure initiatives in the

FBC service territory. However, since OIC 101/2017 was promulgated very recently, the development of more low-carbon electrification measures is in the very early stages and a working relationship with BC Hydro on these matters has not yet been established.

Attachment 25.3

E Source

Targeted Energy-Efficiency and Demand-Response Programs

An Ask E Source Answer

By Michael Colby

February 3, 2016

Question

Can E Source describe any targeted energy-efficiency programs that utilities offer—programs that aim to address electric-system constraints?

Answer

One of the best resources on targeted energy efficiency is a January 2015 Northeast Energy Efficiency Partnerships (NEEP) report, Energy Efficiency As a Transmission and Distribution Resource (PDF). The report provides in-depth analysis of energy efficiency (EE) as a transmission and distribution (T&D) resource and provides several examples of how utilities handle targeted EE. The report provides a summary of examples from the Bonneville Power Administration (BPA) in Washington, Pacific Gas and Electric Co. (PG&E) in California, Central Maine Power in Maine, American Electric Power (AEP) in Michigan, NV Energy in Nevada, Con Edison and The Long Island Power Authority (LIPA) in New York, Portland General Electric (PGE) in Oregon, National Grid in Rhode Island, and Green Mountain Power (GMP) in Vermont. The report covers in detail the projects with Con Edison, Maine, PG&E, and GMP. This NEEP report built upon a February 2012 RAP report entitled US Experience with Efficiency As a Transmission and Distribution System Resource (PDF), which covered most of the same utility projects. Several of the programs detailed in the NEEP report, and others,

are summarized below.

Bonneville Power Administration

In addition to the summary of BPA's targeted energy efficiency projects covered in the NEEP report (p. 16), BPA has a website devoted to its Non-Wires Initiatives that provides feasibility and screening studies from two of its previous non-wires studies.

California

As noted in the NEEP report, the California electric utilities, under the 2013 law known as AB 327, are to "submit to the commission (no later than July 1, 2015) a distribution resources plan proposal to identify optimal locations for the deployment of distributed resources" (p. 44). The distribution resources plan applications for Liberty Utilities, PacifiCorp, Bear Valley Electric Service, SDG&E, Southern California Edison (SCE), and PG&E are available on the California Public Utilities Commission (CPUC) Distribution Resources Plan website. The CPUC website is the best place to follow what is happening with targeted EE in California. It includes maps and data on Integration Capacity Analysis, an overview of the distribution resource plan proceeding, rulemakings, lists of workshops, and a reference library.

The California Independent System Operator (CAISO) is also studying how targeted DSM will fit into long-term resource acquisition plans. Its 2014 report Demand Response and Energy Efficiency Roadmap: Maximizing Preferred Resources (PDF) explores how DR and efficiency measures can be incorporated into planning for future T&D upgrades. In the report, CAISO outlines how it intends to leverage efficiency and DR (including targeted DSM) within four "paths": the demand side, the supply side, operations, and the ever-critical monitoring and evaluation. The report summarizes how the paths fit together and highlights special considerations for any efforts that rely on efficiency and DR to meet system needs.

Southern California Edison

In addition to SCE's response to the distribution resource planning directed by AB 327, mentioned above, SCE is using targeted EE and DR as a resource to meet the needs from the permanent closing of the San Onofre nuclear generating station, a major source of power for areas in central and southern Los Angeles. SCE, along with the CPUC, California

Energy Commission, and CAISO, published the 2013 Preliminary Reliability Plan for LA Basin and San Diego (PDF), detailing the proposed steps to account for the generation loss. SCE is considering developing or procuring 3,250 megawatts (MW) of preferred resources, including localized EE as well as DR, to meet about 50 percent of the total future energy need.

SMUD

SMUD also has focused on using targeted DR to help ensure that its T&D system can meet customer needs. A 2013 presentation, SMUD's Preparations for 2030 and Beyond (PDF), mentions that SMUD is working on an integrated T&D modeling tool that allows for more distributed generation and electric vehicles by optimizing a variety of factors, including the location and timing of DR.

Con Edison—New York

In 2004, to defer T&D investments, Con Edison began offering EE measures to commercial customers on specific distribution networks that were approaching capacity. Since 2004, the program has grown to include residential customers. The Regulatory Assistance Project describes Con Edison's targeted DSM efforts in a 2012 presentation, US Experience with Energy Efficiency as a Transmission and Distribution Resource.

According to the Greentech Media article New York's Con Ed Deferring Substation Upgrades With Demand Management, in August 2014, Con Edison submitted a petition to the New York Public Utility Commission to initiate an innovative demand-management program at the Brownsville substation. The proposal filed with the NYPUC defers the $1 billion substation investment with about "$200 million in novel customer-side load management programs, with an additional $300 million going toward more traditional utility investments, including some substation upgrades, in order to shed 52 megawatts of load from specific areas by 2018." It's still too early in the project for any evaluations to have been generated but it's an excellent example of a large-scale targeted DSM project.

Indiana

Duke Energy operates a targeted DR program to ease peak loads in response to the

retirement of a coal power plant in Indiana. This project is somewhat unique in that it's on an extremely expedited time frame: They need 20 to 40 MW of peak load relief by summer 2016.

Long Island Power Authority

In 2014, PSEG Long Island submitted the Utility 2.0 Long Range Plan Update Document (PDF) to LIPA for approval. The plan includes initiatives designed to defer substantial transmission upgrades in the Far Rockaway region in southern Long Island and the South Fork region in eastern Long Island (details on infrastructure deferment begins on p. 14).

New York State Energy Research and Development Authority and National Grid

Solar developments are another way that electric utilities are seeking to defer system upgrades. For instance, NYSERDA and National Grid are piloting "locational incentives" to spur new solar developments along specific distribution networks. According to the Executive Summary of the Solar Electric Power Association report, "Locational Deployment of Distributed Solar," National Grid is considering deferring $2.9 million in substation upgrades with geotargeted solar incentives.

Central Hudson Gas & Electric

As announced in the press release Central Hudson Gas & Electric Selects Comverge for Targeted Demand Management Program, Comverge notes that it was chosen to implement a targeted DR and EE program for Central Hudson Gas & Electric. The program will aim to alleviate constraints on specific load pockets in the Central Hudson service territory. Central Hudson lists the targeted DR program as one of its four projects in support of the New York Reforming the Energy Vision (NY REV) initiative on its website.

National Grid—Rhode Island

National Grid's Energy Efficiency Plan for 2016 (PDF) mentions that its 2016 system reliability procurement will continue an existing "non-wires" pilot in the towns of Tiverton and Little Compton (pp. 19–20). Additional information about the pilot can be found on National Grid's website for the pilot known as DemandLink.

Vermont

Vermont has a fairly long history with targeted EE and its efforts are described in detail starting on p. 48 in the NEEP report mentioned above. Efficiency Vermont has used geographic targeting to alleviate load-related problems in the St. Albans area, as explained in the blog 2014 Results: One Town's Energy Savings. The Efficiency Vermont 2015–2017 Triennial Plan (PDF) notes that Efficiency Vermont will participate in the Vermont System Planning Committee's (VSPC's) subcommittee on geographic targeting. The VSPC Subcommittee website presents more information about the Geographic Targeting Subcommittee, including meeting agendas, meeting minutes, and other related documents. The 2014 VSPC Annual Report (PDF) provides an update on the 2012–2014 geotargeting efforts and recommends the continuation of one of the projects (p. 19) and the discontinuation of another (p. 20) due to low load growth.

Attachment 29.1

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 101 *, Approved and Ordered* March 01, 2017

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that the Greenhouse Gas Reduction (Clean Energy) Regulation, B.C. Reg.102/2012, is amended as set out in the attached Schedule.

Minister of Energy and Mines and Minister Responsible for Core Review

Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section: *Clean Energy Act*, S.B.C. 2010, c. 22, s. 35

Other: OIC 295/2012

February 7, 2017 R/54a/2017/27

SCHEDULE

1 The Greenhouse Gas Reduction (Clean Energy) Regulation, B.C. Reg.102/2012, is amended by adding the following section:

Prescribed undertaking – electrification

4 (1) In this section:

"benefit", in relation to an undertaking in a class defined in subsection (3) (a) or (b), means all revenues the public utility reasonably expects to earn as a result of implementing the undertaking, less revenues that would have been earned from the supply of undertaking electricity to export markets;

"cost", in relation to an undertaking in a class defined in subsection (3) (a) or (b), means costs the public utility reasonably expects to incur to implement the undertaking, including, without limitation, development and administration costs;

"cost-effective" means that the present value of the benefits of all of the public utility's undertakings within the classes defined in subsection 3 (a) or (b) exceeds the present value of the costs of all of those undertakings when both are calculated using a discount rate equal to the public utility's weighted average cost of capital over a period that ends no later than a specified year;

"natural gas processing plant" means a facility for processing natural gas by removing from it natural gas liquids, sulphur or other substances;

"specified year", in relation to an undertaking within a class defined in subsection (3), means

(a) a year determined by the minister with respect to an identified public utility, or

(b) if the minister does not make a determination for the purposes of paragraph (a), 2030;

"undertaking electricity" means electricity that is provided to customers in British Columbia as a result of an undertaking and is in addition to electricity that would have been provided had the undertaking not been carried out.

(2) A public utility's undertaking that is in a class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:

(a) for the purpose of reducing greenhouse gas emissions in British Columbia, the public utility constructs or operates an electricity transmission or distribution facility, or provides for temporary generation until the completion of the construction of the facility, in northeast British Columbia primarily to provide electricity from the authority to

(i) a producer, as defined in section 1 (1) of the Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation, B.C. Reg. 495/92, or

(ii) an owner or operator of a natural gas processing plant;

(b) the public utility reasonably expects, on the date the public utility decides to carry out the undertaking, that the facility will have an in-service date no later than December 31, 2022.

(3) Subject to subsection (4), a public utility's undertaking that is in a class defined in one of the following paragraphs is a prescribed undertaking for the purposes of section 18 of the Act:

(a) a program to encourage the public utility's customers, or persons who may become customers of the public utility, to use electricity, instead of other sources of energy that produce more greenhouse gas emissions, by

(i) educating or training those customers respecting energy use and greenhouse gas emissions, carrying out public awareness campaigns respecting those matters, or providing energy management and audit services, or

(ii) providing funds to those persons to assist in the acquisition, installation or use of equipment that uses or affects the use of electricity;

(b) a program to encourage the public utility's customers, or persons who may become customers of the public utility, to use electricity instead of other sources of energy that produce more greenhouse gas emissions, by

(i) educating, training, providing energy management and audit services to, or carrying out awareness campaigns respecting energy use and greenhouse gas emissions for, or

(ii) providing funds to

persons who

(iii) design, manufacture, sell, install or, in the course of operating a business, provide advice respecting equipment that uses or affects the use of electricity,

(iv) design, construct, manage or, in the course of operating a business, provide advice respecting energy systems in buildings or facilities, or

(v) design, construct or manage district energy systems;

(c) a project, program, contract or expenditure for research and development of technology, or for conducting a pilot project respecting technology, that may enable the public utility's customers to use electricity instead of other sources of energy that produce more greenhouse gas emissions;

(d) a project, program, contract or expenditure supporting a standards-making body in its development of standards respecting

(i) technologies that use electricity instead of other sources of energy that produce more greenhouse gas emissions, or

(ii) technologies that affect the use of electricity by other technologies that use electricity instead of other sources of energy that produce more greenhouse gas emissions;

(e) a project for the construction, acquisition or extension of a plant or system, that the public utility reasonably expects is necessary to meet the public utility's incremental load-serving obligations arising as a result of an

undertaking defined in paragraph (a), (b), (c) or (d), if the public utility reasonably expects any one such project to cost no more than $20 million.

(4) An undertaking is within a class of undertakings defined in paragraph (a) or (b) of subsection (3) only if, at the time the public utility decides to carry out the undertaking, the public utility reasonably expects the undertaking to be cost-effective.