Diane Roy
Vice President, Regulatory Affairs

Gas Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

Electric Regulatory Affairs Correspondence
Email: electricity.regulatory.affairs@fortisbc.com

FortisBC
16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7349
Cell: (604) 908-2790
Fax: (604) 576-7074
Email: diane.roy@fortisbc.com
www.fortisbc.com

November 15, 2018

Commercial Energy Consumers Association of British Columbia
c/o Owen Bird Law Corporation
P.O. Box 49130
Three Bentall Centre
2900 – 595 Burrard Street
Vancouver, BC
V7X 1J5

Attention: Mr. Christopher P. Weafer

Dear Mr. Weafer:

Re: FortisBC Energy Inc. (FEI)

Project No. 1598946

2017 Long Term Gas Resource Plan (LTGRP) (the Application)

Response to the Commercial Energy Consumers Association of British Columbia (CEC) Information Request (IR) No. 3

On December 14, 2017, FEI filed the Application referenced above. In accordance with British Columbia Utilities Commission Order G-132-18 establishing the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to CEC IR No. 3.

If further information is required, please contact Ken Ross at (604) 576-7343.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

I. CEC INFORMATION REQUEST ON THE TESTIMONY OF MICHAEL SLOAN AND JOHN DIKEOS OF ICF

1. Reference: Exhibit B-11, ICF page 3

> **Introduction to ICF**
>
> ICF is one of the largest consultants offering policy, management and technical expertise to the North American gas and oil industry. ICF is also one of the largest DSM support contractors in North America. We help utilities assess DSM potential, design and implement DSM programs, and evaluate DSM program impacts.
>
> In addition to past work with many private sector clients in the gas and oil industry, we have also been consultants to the U.S. Department of Energy (DOE), the Federal Energy Regulatory Commission (FERC), and the U.S. Environmental Protection Agency (EPA), as well as government agencies in Canada, India, Mozambique, Qatar, and members of the European Union. We also undertake special studies for industry organizations like the American Petroleum Institute (API), Interstate Natural Gas Association of America (INGAA), and America's Natural Gas Alliance (ANGA), among others.
>
> ICF is known for its quantitative, analytical approaches to solving client problems. We have developed models that reflect the present and projected conditions of the oil and natural gas industries, the electric power industry, the coal industry, and of the impact of environmental regulation across all energy industry sectors.

1.1 Please provide a summary of ICF's experience in Canada, and in BC.

Response:

FEI consulted with ICF to provide the following response.

ICF has been in existence since 1969, and currently has over 6,000 employees, including 4 offices and over 100 employees based in Canada. As such, FEI and ICF interpret this question as a request to illustrate ICF's experience in DSM, macro-level energy studies, and energy technology and market characterizations by providing select examples of projects that ICF has worked on.

CVs for Mr. Sloan and Mr. Dikeos are attached as part of the ICF report in Exhibit B-11. These CVs provide summaries of their experience in Canada and in BC.

ICF has provided the following sample of recent projects to demonstrate its experience with DSM in British Columbia and in Canada more broadly.

A selection of ICF's recent experience in British Columbia includes:

- Support for the 2019-2022, 2014-2018, and 2012-2013 DSM Plans (FortisBC, 2012-2018);

- Several Pre-Feasibility DSM Technology Assessments (FortisBC, 2013-Present);
- Evaluation Support, Continuous Optimization Program and Regulation of Televisions (BC Hydro, 2014);
- End Use Load Forecast Study (FortisBC, 2012); and
- BC Natural Gas Conservation Potential Review (FortisBC, 2010).

A selection of recent experience in other Canadian jurisdictions includes:

- DSM Program Design and Implementation:
    - Implementation of the SuiteSaver Program (Toronto Hydro, 2018-Present);
    - Design and Implementation of the Business Energy Savings Program (Energy Efficiency Alberta, 2017-Present);
    - Design and Implementation of the AgriPump Rebate Program (Niagara Peninsula Energy and Hydro One Networks, 2017-Present);
    - Implementation of the Industrial Accelerator Program in Ontario (IESO, 2017-Present);
    - Implementation of Municipal Energy Audit Program (Alberta Urban Municipalities Association, 2017-Present);
    - Design and Implementation of the Industrial Energy Optimization Program (SaskPower, 2012-Present);
    - Design and Implementation of Commercial Lighting Incentive Program (SaskPower, 2012-Present);
    - Support for the Northern Industrial Electricity Rate Program (Ontario Ministry of Northern Development and Mines, 2011-Present);
    - Technical Reviews of Save on Energy Incentive Applications (Multiple Ontario LDCs, 2008-Present); and
    - Design and Implementation of the Energy Concierge Pilot (Niagara Peninsula Energy, 2015-2017).
- Conservation Potential and Other Macro-Level Studies:
    - Natural Gas Integrated Resource Planning Study (Enbridge and Union Gas, 2016-2018);

- Municipal Electricity Profile (IESO, 2017-2018);
- Future of Home Heating (MaRS Discovery District, 2017-2018);
- Long Term Carbon Price Forecast and Marginal Abatement Cost Curve (Ontario Energy Board, 2017);
- Energy Benchmarking Study Update (Ontario Ministry of Environment and Climate Change, 2015-2016);
- Ontario Natural Gas Conservation Potential Study (Ontario Energy Board, 2015-2016);
- Yukon Conservation Potential Review & Program Design (Yukon Energy Corporation, 2011-2016); and
- CDM Potential Study for Newfoundland (Newfoundland and Labrador Hydro and Newfoundland Power, 2015 and 2008).

- Market Characterization and Technology Assessments:
  - Commercial Facility Equipment Survey (Newfoundland Power, 2018-Present);
  - Survey of Energy Consumption in Multi-Unit Residential Buildings (Natural Resources Canada, 2017-Present);
  - Lighting Sector Profile (NRCan, 2017);
  - Pre-Feasibility DSM Technology Assessment: Domestic Hot Water Recirculation System Controls (Union Gas, 2016-2017);
  - Lighting and Consumer Electronics Standards Development Support (NRCan, 2012-2017); and
  - Pre-Feasibility DSM Technology Assessment: Compact Furnaces (Canadian Gas Association, 2015).

1.2 Please identify the Canadian agencies referred to in paragraph 2 above.

Response:

FEI consulted with ICF to provide the following response.

ICF has worked with numerous Canadian agencies that engage in energy oversight. These include but are not limited to the following:

- Natural Resources Canada;
- National Energy Board;
- Indigenous and Northern Affairs Canada;
- Ontario Energy Board;
- Ontario Ministry of Energy;
- Ontario Ministry of Northern Development and Mines;
- Nova Scotia Department of Energy; and
- Nova Scotia Public Utilities Board.

1.3 Please provide a brief discussion of ICF's experience representing ratepayer interests, and particularly their experience in Canada and BC.

Response:

FEI consulted with ICF to provide the following response.

ICF has worked for a variety of organizations that represent the interests of entities that pay rates, fees, or tolls toward energy infrastructure and services in Canada and in BC. These include but are not limited to the government agencies identified in response to CEC IR 3.1.2, as well as the following:

- Association of Power Producers of Ontario (APPrO);
- Industrial Gas Users Association (IGUA);
- Canadian Association of Petroleum Producers (CAPP);
- Northeast Utilities; and
- A variety of companies that are ratepayers on natural gas and electric systems, including Union Gas, Enbridge Gas, and Nova Scotia Power, among others.

1.4 Please identify which Canadian jurisdiction(s) can be considered as currently 'leading' in terms of DSM, and identify the leading practices.

Response:

FEI consulted with ICF to provide the following response.

This response also addresses CEC IRs 3.1.4.1, 3.1.5, 3.1.5.1, and 3.1.6. ICF's Exhibit B-11 report focuses on the potential for DSM infrastructure deferral and associated studies that ICF has prepared. As such, FEI and ICF interpret this question to relate specifically to DSM infrastructure deferral and the associated studies ICF discusses in its Exhibit B-11 report.

In the context of the jurisdictional review for the IRP study that ICF completed on behalf of Enbridge and Union Gas, leading natural gas utilities were identified as having experience working on integrated resource plans. The review evaluated how these utilities address issues related to broad-based DSM and facilities planning, and issues related to the impact of DSM programs on new subdivision and community planning. The only other Canadian natural gas utility included in this review was FortisBC; Enbridge and Union Gas clearly have some experience with analysis and pilot testing of DSM as an alternative to facility investments. Mr. Dikeos and Mr. Sloan were deeply involved in all aspects of the IRP study that ICF completed on behalf of Enbridge and Union Gas.

Several US utilities (and jurisdictions) were included in the scope of the jurisdictional review that ICF completed as part of the IRP study for Enbridge and Union Gas. US utilities with experience for considering peak demand impacts and natural gas DSM as an alternative to facilities investments included NW Natural Gas (Oregon and Washington) and Avista (Washington, Idaho, and Oregon), Puget Sound Energy (Washington), and Vermont Gas Systems (Vermont). ICF is aware that Con Edison has recent experience in this area as well. Mr. Sloan worked closely with Con Edison in the development of its non-pipelines solution program designed to solicit DSM and other supply alternatives. These efforts included assistance to Con Edison in the development of the Non-Pipeline Solutions request for proposals, and the evaluation of proposal responses. Mr. Dikeos' experience has been primarily in Canada, although he has worked extensively with ICF staff with U.S. experience, hence is broadly aware of the issues and trends in this area in the U.S.

Due to the risks associated with DSM-driven infrastructure deferral, as identified on pages 13-15 of ICF's Exhibit B-11 report, ICF does not believe that any one utility should shoulder all of this endeavor alone. This means that FEI could be <u>one</u> of the 'leading' utilities in this area, but in the interest of its ratepayers ICF does not believe that FEI should be <u>the</u> 'leading' utility. FEI notes that, as explained in the response to BCUC IR 3.75.5.1, since the results of next steps are uncertain and select jurisdictions are proceeding with additional analysis and pilot testing, it would be prudent for FEI to proceed cautiously and assess the results of work in other jurisdictions to inform next steps.

1.4.1 Please discuss Mr. Dikeos' and Mr. Sloan's experience in those jurisdictions and their involvement in the 'leading practices', if any.

Response:

Please refer to the response to CEC IR 3.1.4.

1.5 Please identify which US jurisdiction(s) can be considered as currently 'leading' in terms of DSM, and identify the leading practices.

Response:

Please refer to the response to CEC IR 3.1.4.

1.5.1 Please discuss Mr. Dikeos' and Mr. Sloan's experience in those jurisdictions and their involvement in the 'leading practices', if any.

Response:

Please refer to the response to CEC IR 3.1.4.

1.6 Do Mr. Dikeos and Mr. Sloan believe that FEI could be a 'leading' utility in terms of natural gas DSM, including infrastructure deferral related DSM? Please explain why or why not.

Response:

Please refer to the response to CEC IR 3.1.4.

2. Reference: Exhibit B-11, ICF page 5

> Mr. Grevatt's testimony related to the Ontario Energy Board process for natural gas infrastructure planning is relevant to this discussion, although his conclusions are not up-to-date with the current state of the process in Ontario, and do not reflect an accurate assessment of the state of implementation of these practices in Ontario.

2.1 Please discuss the 'current state of the process' in Ontario and highlight the differences between Mr. Grevatt's view with that the authors'.

Response:

FEI consulted with ICF to provide the following response.

Section 3.1.2 of the Exhibit B-11 report of Mr. Sloan and Mr. Dikeos provides additional details on the state of the process for natural gas infrastructure planning in Ontario. The authors' introductory explanation to Section 3 and their conclusions in Section 3.3 of ICF's Exhibit B-11 report detail how ICF's findings on the state of process in Ontario as well as its other Section 3 findings relate to Mr. Grevatt's view.

3. Reference: Exhibit B-11, ICF page 6

> ICF's review of the state of the industry indicated that there is limited precedent for, or evidence of, natural gas utilities' use of geo-targeted DSM or dedicated DR programs to directly impact facilities planning. There is a recognition that DSM programs can impact demand, hence impacting the need for future facilities, but almost no experience with evaluating the impact of DSM on the need for specific targeted facilities.

3.1 The CEC notes that the authors utilize the term 'limited' precedent for the use of geo-targeted DSM or dedicated DR programs. Please identify any experience that the authors are aware of in which natural gas utilities have used or attempted to utilize DSM to directly or indirectly impact facilities planning that is not included in the evidence submitted.

<u>Response:</u>

FEI consulted with ICF to provide the following response.

The recent programs that the authors have reviewed are summarized in ICF's Exhibit B-11 evidence and in the associated IRP study that ICF completed on behalf of Enbridge and Union Gas. A recent new report by the U.S. Energy Information Administration (EIA) identified two additional programs by Southern California Gas and National Grid in New York City that were too recent to include in the ICF report. According to the U.S. EIA:

> Although DR has become fairly common in the electricity sector, programs to reduce natural gas demand have only recently been adopted. In early 2017, Southern California Gas Company (SoCalGas) piloted the Seasonal Savings program, which used direct load control to adjust about 50,000 residential thermostats according to a household's schedule and preferences to reduce short-term peak demand. In the winter of 2017–2018, 16 National Grid customers in New York City and Long Island participated in a DR program aimed at commercial and industrial customers, where large heaters or machinery running on natural gas were turned on and off to manage peak demand days.[1]

3.2 The CEC notes that the authors utilize the term 'almost no' experience in evaluation. Please identify any experience that the authors are aware of in

[1] US Energy Information Administration (2018). Today in Energy, November 6, 2018. https://www.eia.gov/todayinenergy/detail.php?id=37412.

which natural gas utilities have or have attempted to assess the impact of DSM on specific evidence that is not included in the evidence submitted.

Response:

FEI consulted with ICF to provide the following response.

The reference to evaluation in the authors' testimony refers to evaluation of peak period impacts for natural gas utilities. The experience that ICF is aware of is summarized in ICF's Exhibit B-11 evidence and in the associated IRP study that ICF completed on behalf of Enbridge and Union Gas. ICF is also generally aware that a number of utilities have started to purchase meters capable of reading peak period demand, and expects that some of these utilities are starting to consider evaluation of the impacts of different programs on peak period demand.

3.3 Please cite any references and/or cases in which it is recognized that DSM programs can impact the need for future facilities and provide the dates of these recognitions.

Response:

FEI consulted with ICF to provide the following response.

DSM is generally acknowledged to impact future demand, and hence the generic need for future facilities. The value of this impact is generally accounted for in the avoided costs used to evaluate DSM programs. Mr. Sloan assisted natural gas utilities in the development of avoided costs with facilities cost impacts included as early as 1989. FEI sees no value in requesting ICF to conduct an assessment of historical DSM programs that would be necessary to list all of the DSM programs that have included a generic facilities cost component in the avoided cost used to evaluate the programs. Please also see the response to BCUC IR 3.75.4 which explains that FEI includes a distribution adder in its avoided cost that is intended to capture the value for 'passive deferral of infrastructure investment'.

4. Reference: Exhibit B-11, ICF pages 6 and 7 and page 18

> Overall, our review of existing DSM programs at North American gas utilities in other jurisdictions found that the natural gas industry has extremely limited experience integrating DSM into the facilities planning process and in using targeted DSM to reduce the cost of facility investments. Furthermore, ICF did not identify any natural gas utilities in North America that actively consider the impact of DSM programs on peak hour or peak day demand forecasts
>
> used for facilities planning. Since ICF's study was initiated in October of 2016, a few gas utilities have begun to consider these impacts. However, these efforts remain in the early stages.
>
> We also found that the gas utilities that have contemplated the potential to use DSM programs to avoid or defer specific infrastructure projects have generally expressed concerns about the reliability of the DSM impacts as a facility investment alternative due to the lack of information on the measured impacts of DSM on peak hourly demand. The lack of accurate metered data on natural gas peak period demand, the long lead-time required to incorporate DSM as a potential alternative to infrastructure investments, and equity concerns resulting from geo-targeted DSM programs were also significant concerns.
>
> 4. **Cross-Subsidization:** Currently the costs of new infrastructure are shared across customer classes. Geo-targeted DSM programs have the potential to lead to cross-subsidization between customer classes, and between DSM participants and other customers.
>
> 5. **Customer Discrimination:** By definition, the use of geo-targeted DSM programs to reduce infrastructure investments will lead to discrimination between customers at the boundary of the geo-targeted region. Customers within the boundary will be eligible for potentially significant incentives, while customers outside of the boundary will not.

4.1 The authors state that:

> 'a few gas utilities have begun to consider these impacts. However, these efforts remain in the early stages'.

Please identify all the gas utilities that have begun to consider the impacts, and provide more detail regarding the 'early stage' at which each is currently.

Response:

FEI consulted with ICF to provide the following response.

In addition to Enbridge/Union Gas in Ontario as discussed in Exhibit B-11, the authors are aware of the following gas utilities/activities:

- NW Natural: This utility plans to treat DSM as a resource option in its 2018 IRP and is considering the peak hour impacts of geo-targeted DSM through the design of a pilot project.

- Avista Utilities: The 2016 Avista IRP indicated that they are aiming to quantify the value of peak day DSM impacts.
- Puget Sound Energy: This utility treated DSM as a supply-side resource to meet their forecasted peak day demand over a 20 year planning period.
- ConEdison: Currently studying the potential for demand response programs as a separate element of their Non-Pipeline Solutions effort. On August 9, 2018, Con Edison received approval from the New York Commission to implement a gas demand response pilot program.

4.2 Please provide more detail as to what the authors would view as constituting an 'emerging' best practice.

<u>Response:</u>

FEI consulted with ICF to provide the following response.

The authors consider an 'emerging best practice' to be a practice that has been adopted by a small but growing number of entities, for which sufficient evidence exists to prove that the 'emerging best practice' provides net value beyond that of the established practice. Based on this definition, the authors view DSM-driven infrastructure deferral to be an 'emerging practice', but a practice that still requires more evidence to prove its value relative to the established practice.

4.3 What measurement options are available and/or being developed in order to assess the impacts of DSM on peak hourly demand? Please discuss and provide quantification of any known costs.

<u>Response:</u>

FEI consulted with ICF to provide the following response.

This IR also addresses CEC IRs 3.4.4, 3.14.2 and 3.14.2.1. FEI is aware that some advanced gas metering infrastructure (AMI - utility customer consumption meters) has features that can likely assist with the analysis of DSM impacts on peak demand. The extent to which the information that can be provided by AMI can provide a complete understanding of the impacts of

DSM on peak demand is not yet certain. The costs for AMI solutions can vary broadly depending on the design of the AMI program being implemented.

FEI has also done preliminary scanning of possible measurement and monitoring solutions that have potential to attach behind the meter, nearer or at the end-use appliance, and provide more frequent usage related data specific to the end-use equipment. One example is a sonic meter that would measure changes in sound in the pipe to identify when an appliance is in use. However, FEI has not yet identified any such measuring and monitoring equipment of this nature that has a proven track record for providing results in this type of application and therefore has not fully assessed the cost implications. The extent to which measuring and monitoring at the end-use equipment may be needed for or may assist in understanding the impacts of DSM on peak demand requires further exploration.

FEI's preliminary exploration of this issue suggests that fairly granular data will be required to understand peak demand characteristics of existing appliances and potential new energy conservation measures. Additionally, as suggested by ICF, a natural gas meter capable of high resolution measurements (i.e., on the order of 0.001 GJ) is necessary to assess the impacts of DSM on peak hourly demand. FEI expects that this data may need to be collected on a timing frequency of 15 minutes or better although hourly measurement may be sufficient. Please also refer to the response to CEC IR 3.14.1. ICF also points out that several utilities are researching the availability of meters capable of providing data at this resolution. Further exploration of the implications of these features on costs is required.

4.4 What options are or could be available to produce accurate metered data on natural gas peak demand? Please discuss and provide quantification of any known costs.

Response:

Please refer to the response to CEC IR 3.4.3.

4.5 What timeframe is considered to be a 'long lead time'?

Response:

FEI consulted with ICF to provide the following response.

ICF's research, including consultations with staff at several gas utilities, suggests that a lead time as long as five years would be required to incorporate DSM as an effective strategy to defer infrastructure investments. Please refer to the response to BCUC IR 3.79.1 for additional details on infrastructure planning lead times.

4.6 Please confirm that the term 'equity concerns' refers to the concerns of 'cross-subsidization' and 'customer discrimination' on page 18.

Response:

FEI consulted with ICF to provide the following response.

Confirmed.

4.7 Please discuss why a customer within a boundary being geo-targeted for DSM receiving benefits (incentives) for reducing demand would be a case of discrimination vis-a-vis a customer outside a boundary who could not contribute.

Response:

FEI consulted with ICF to provide the following response.

As discussed in FEI's responses to BCUC IRs 3.80.3 and 3.80.3.1, geo-targeted DSM initiatives still require further exploration and the potential for customer discrimination will depend on the design of the program. Based on the example suggested in the preamble, in FEI's view, the customer outside a boundary of geo-targeted DSM would not have access to the benefits (i.e. incentives) but will be paying for the share of costs for such geo-targeted DSM activities. This situation could be considered discriminatory based on their location outside the boundary while only customers within the boundary will have full access to the benefits.

4.8 Please confirm that new facilities can impact rates for all customers regardless of geo-geography, within a 'postage stamp' rate system for customer class rates.

Response:

Confirmed. However, it is important to note that new infrastructure facilities will improve FEI's system as a whole and all customers that have access to FEI's service via its infrastructure will benefit from the improvement. For facilities that benefit a customer (a new service) or group of customers (a new main), there are contributions required to avoid cross-subsidization by other customers.

5. Reference: Exhibit B-11, ICF page 7

> Furthermore, ICF assessed activity in the electric power industry as part of our 2017 best practice review. Our review indicated that some progress has been made in that industry to defer transmission and distribution costs using targeted energy efficiency. However, differences in utility cost structure, duration of peak period requirements, and availability of data on DSM impacts leads us to conclude that geo-targeted DSM programs are likely to be more cost effective for the electric industry than they are for the natural gas industry, per equivalent amount of energy delivered (GJ of delivered energy), and that the electric industry experience provides only relatively limited value as an example for the gas industry.
>
> More recent efforts by Con Edison, the Ontario natural gas utilities, and Northwest Natural Gas are addressed below.

5.1 Please provide ICF's 2017 best practice review or indicate where it is provided in the proceeding evidence.

<u>Response:</u>

FEI consulted with ICF to provide the following response.

A summary of the best practice review can be found within section 2 of the Executive Summary of the IRP Report (see links below). The full best practice review, which is included in the IRP report, is currently not available publicly. Please see below for access details to the publicly available information.

- Enbridge, EB-2017-0127 / EB-2017-0128 – DSM Mid-Term Review, Submission to OEB, Jan. 15, 2018, available at: http://www.rds.oeb.ca/HPECMWebDrawer/Record/596649/File/document
- Union Gas, EB-2017-0127 – DSM Mid-Term Review, Submission to OEB, Jan. 15, 2018, available at: http://www.rds.oeb.ca/HPECMWebDrawer/Record/596652/File/document

6. Reference: Exhibit B-11, ICF page 7

> **3.1.2 Review of Ontario Gas Utility Efforts**
>
> In Ontario, the Ontario Energy Board (OEB) directed the two major natural gas utilities, Enbridge and Union Gas, to evaluate the potential to use DSM to avoid or defer (reduce) infrastructure costs. The study was designed to assess the implementation of broad-based or geo-targeted DSM programs to meet the forecasted hourly peak energy demand, consistent with the primary goals and principles of facilities planning, to provide reliable natural gas service with reasonable costs. ICF was engaged by the utilities to undertake the study and it was completed in early 2018.

6.1 Please provide the study referenced above, if different from the 2017 best practice review, or indicate where it is provided in the proceeding evidence.

Response:

FEI consulted with ICF to provide the following response.

The study is identical to the 2017 best practice review referenced in CEC IR 3.5.1. Please refer to the response to CEC IR 3.5.1 for access details to the best practice review.

6.2 Please elaborate on the differences between implementation of broad-based and geo-targeted DSM programs.

Response:

FEI consulted with ICF to provide the following response.

Broad-based DSM programs are marketed to a large portion of the consumer base and may lead to passive deferral of infrastructure investments, whereas geo-targeted DSM programs are targeted to specific locations and may lead to active deferral of infrastructure investments. In addition and as noted in the response to BCUC IR 3.75.3, geo-targeted DSM programs would tend to be smaller than most broad-based DSM programs and, for an equivalent program size and geo-targeted programs, are expected to be more expensive per unit impact than broad-based DSM programs. This is due to several factors, including the need for metering and on-going monitoring of impacts with geo-targeted DSM programs.

Both broad-based and geo-targeted DSM programs can theoretically be designed with the intention of reducing peak demand by prioritizing measures through the use of a peak demand DSM supply curve. While measure selection and incentive levels may differ for a broad-based DSM program focused on peak demand reductions, the implementation of such a program would be very similar to the way FEI currently implements its DSM programs. By comparison, a geo-targeted DSM program focused on peak demand reduction would require additional planning to design the program specific to the area, additional marketing to ensure sufficient rates of measure adoption, additional metering to ensure that the adoption of the DSM measures is having the desired effect of reducing peak demand, and additional oversight in general to ensure that the program is on track to successfully defer the need for infrastructure investment. It is also worth noting that a geo-targeted DSM program would not benefit from the same economies of scale as a broad-based DSM program.

7. Reference: Exhibit B-11, ICF page 7 and 8

> ICF's analysis of the potential for geo-targeted DSM to reduce peak hour demand growth in Ontario suggests that, under certain circumstances, there may be potential to reduce infrastructure investments using geo-targeted DSM programs. The results showed that DSM can cost effectively defer infrastructure investments in certain situations where annual peak hour demand growth is limited and facility project costs are relatively high. However, ICF's research indicated that there are likely to be only a limited number of projects where targeted DSM might make sense. At a high level, the research suggests that it is often expensive and ineffective to assess DSM as an alternative to gas infrastructure projects; especially in cases where demand growth is not the primary driver for the facility investment.
>
> ICF's study also found that there are a number of practical considerations impacting the ability to use geo-targeted DSM. The potential penetration rate for DSM programs can be a limiting factor in the ability to use DSM to offset demand growth, particularly in rapidly growing areas. There is also likely a minimum size for facilities investments where geo-targeted DSM programs could be cost effectively implemented due to program development, implementation, and monitoring costs.
>
> Furthermore, the study found that data limitations on the potential impacts of DSM programs on peak period demand make reliance on DSM to avoid or defer specific infrastructure investments highly problematic at the current time. The main conclusion of this study is that additional research is necessary before the utilities would be able to rely on DSM to avoid or defer new infrastructure investments.

7.1 The authors reference both broad-based DSM and geo-restricted DSM topics for their report, but discuss only the geo-targeted DSM results. Please provide an overview of the results ICF found related to broad-based DSM.

Response:

FEI consulted with ICF to provide the following response.

The broad-based analysis provided insights into the potential impacts of DSM on peak demand at a high level across the entire Enbridge and Union Gas service territories. For example, the broad-based analysis highlighted the relative peak reduction potential of the different sectors (e.g., residential vs. commercial).

The results of the broad-based analysis were leveraged for the geo-targeted analysis (i.e., the results of the broad-based analysis were scaled to reflect the potential of a geo-targeted DSM program). The broad-based analysis was not used to assess the cost-effectiveness of DSM from the perspective of deferral of a specific infrastructure project. Generally, the impact of broad-based DSM programs are reflected in the demand data included in the forecasts used to determine the need for new infrastructure, and the use of a broad-based DSM program to impact the need for a specific infrastructure project would be limited due to the need to allocate the infrastructure cost savings over a wider range of DSM activity that did not directly impact the need for the facility.

7.2 Under what conditions would a utility likely experience a situation in which annual peak hour demand growth is limited and facility project costs are relatively high? Please discuss.

Response:

FEI consulted with ICF to provide the following response.

FEI notes that the question refers to the two circumstances (limited peak hour demand growth, relatively high facility project costs) in general without specifically asking how such circumstances would relate to DSM. Various conditions could exist under which a utility is likely to experience such circumstances but these conditions are not suitable for DSM infrastructure deferral. If peak hour demand growth is limited but so low that it is not the primary rationale for the infrastructure project, DSM would not provide any value. Accommodating system reliability needs (e.g. replacing aging infrastructure) or the need to relocate infrastructure for various reasons could, in theory, drive such a project.

However, these situations do not satisfy the description presented in the preamble such that geo-targeted DSM could provide a benefit. A much more limited set of conditions apply to this specific purpose. Forecast peak hour demand growth must be limited but not so low as to diminish the value of DSM and the driver of that growth must also be amenable to DSM measures. At the same time, project-specific circumstances, such as project size, project length, and the nature of the area where the project is located (as explained in the response to BCUC IR 3.76.6), need to cause relatively high project costs. Again in theory, these conditions could occur on FEI's system, however, none of the transmission infrastructure projects discussed in Section 6 of the 2017 LTGRP have the characteristics described in the preamble. Please also refer to the response to BCUC IR 3.79.3 for further discussion of infrastructure investment under 'limited growth'.

7.3 In what ways might BC differ from the Ontario natural gas utilities that the authors studied, and how might this impact the results? Please explain.

Response:

FEI consulted with ICF to provide the following response.

Although the specific details of a similar study conducted for BC would differ, it is likely that such an analysis would yield the same broad conclusions:

- Under certain circumstances (i.e., low peak demand growth, high facility project costs), it is feasible that geo-targeted DSM could cost-effectively defer the need for infrastructure investment; and
- Due to the increased reliability needs of facility planning, more research is needed to understand and quantify the impacts of DSM on peak demand.

The potential for DSM to reduce peak demand depends on several factors, including but not limited to the local climate, the distribution of local demand by sector, the types of measures being implemented, and the current penetration of these measures. However, ICF has not completed a detailed comparison of BC and Ontario and is unable to provide further insight into the differences between these two jurisdictions at this time.

8. Reference: Exhibit B-11, ICF page 9 and 10

> Con Edison is in a period of rapid natural gas demand growth in the New York City region due to customer conversions from fuel oil to natural gas and to serve new load. The growth in demand is straining the available capacity on the interstate pipeline system serving sections of Con Edison's natural gas distribution system, and Con Edison is evaluating new pipeline contract options to increase capacity into its service territory, as well as non-pipeline solutions to reduce the need for new pipeline capacity. As part of this effort, Con Edison requested proposals from market participants to provide non-pipeline solutions (NPS). The results of this effort were submitted to the New York Public Service Commission on September 28, 2018.

> Despite all of these efforts, "Con Edison remains concerned about its ability to supply continued growing customer heating demands for natural gas with currently available resources, and a temporary moratorium on new gas customer connections remains a possibility."[17]
>
> Although natural gas DSM is part of the Con Edison's portfolio of non-pipelines solutions and may help defer the need for new pipeline capacity, Con Edison's situation is somewhat unique and natural gas DSM would be even less cost-effective in most other jurisdictions where the comparative cost of gas infrastructure is much lower than in New York.

8.1 What is driving the conversions from fuel oil to natural gas in New York City?

Response:

FEI consulted with ICF to provide the following response.

The conversion from fuel oil to natural gas in New York City is primarily driven by regulation, although ICF understands that there is also a component driven by cost and environmental awareness.

8.2 Please provide Con Edison's rate of natural gas demand growth in New York City.

Response:

FEI consulted with ICF to provide the following response.

FEI and ICF interpret this question to inquire about Con Edison's rate of natural gas peak demand growth. Con Edison's regulated natural gas utility delivers gas to approximately 1.1 million customers in Manhattan, the Bronx, parts of Queens and most of Westchester County. The Con Edison 2017 Annual Report provides details regarding natural gas demand growth in this service territory:

> The company forecasts an average annual growth of the gas peak demand over the next five years at design conditions to be approximately 1.2 percent in its service area.[2]

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[2] ConEdison (2017). 2017 Annual Report. p. 24. URL: http://phx.corporate-ir.net/External.File?item=UGFyZW50SUQ9NDAyNDQ4fENoaWxkSUQ9LTF8VHlwZT0z&t=1&cb=636589031692764246.

9. Reference: Exhibit B-11, ICF page 9 and page 10

> The non-pipeline solutions portfolio selected by Con Edison is projected to reduce growth in peak period capacity requirements on interstate pipelines into the Con Edison Service territory by 84,500 Decathterms (Dth)/day by 2023 at a cost of $305 million. The proposed non-pipeline solutions portfolio includes energy efficiency programs designed to provide 25,000 Dth/day of peak period gas demand reductions, programs designed to convert 12,400 Dth/day of natural gas space heating load to alternative fuels (electric heat pumps), 7,100 Dth/day of increased peak period natural gas supply from Renewable Natural Gas (RNG), and 40,000 Dth/day of peak period natural gas supply from CNG/LNG delivered by truck to strategic locations on the Con Edison system.[15]

> "The Company is pursuing additional measures to address its unprecedented load growth and support reliability. In addition to efforts described in this filing to develop alternatives to traditional pipeline capacity, the Company is taking the following actions to meet customer needs as part of its larger Smart Solutions for Natural Gas Customers effort:
>
> - Doubling its gas energy efficiency targets for 2018, 2019 and 2020;
> - Preparing to launch a gas demand response pilot in Winter 2018/2019;
> - Investigating projects that could increase customer access to renewable thermal resources through business model innovation; and
> - Engaging with pipeline development companies to determine whether a traditional solution to meeting customer heating needs is feasible."

> Despite all of these efforts, "Con Edison remains concerned about its ability to supply continued growing customer heating demands for natural gas with currently available resources, and a temporary moratorium on new gas customer connections remains a possibility."[17]

9.1 Please provide the relevant metrics to place the evidence cited in context. i.e. what is the total growth which will be reduced by 84,500 Decatherms by 2023?

Response:

FEI consulted with ICF to provide the following response.

The Con Edison 2017 Annual Report provides a reasonable baseline for placing the evidence into context:

> The gas peak demand for firm sales customers in CECONY's service area occurs during the winter heating season. The peak day demand during the winter 2017/2018 (through January 31, 2018) occurred on January 6, 2018 when the demand reached 1,410 MDt. "Design weather" for the gas system is a standard to which the actual peak demand is adjusted for evaluation and planning purposes. The company estimates that, under design weather conditions, the 2018/2019 service area peak day demand will be 1,565 MDt. The forecasted

> peak day demand at design conditions does not include gas used by interruptible gas customers including electric and steam generating stations. The company forecasts an average annual growth of the gas peak demand over the next five years at design conditions to be approximately 1.2.[3]

The 84,500 Decatherms per day represent about 5.1 percent of Con Edison's expected design day demand in 2022/2023. In its initial filing regarding the Smart Solutions for Natural Gas Customers Program, Con Edison indicated that, prior to the impact of potential non-pipeline solutions, it anticipated a shortfall of approximately nine percent of peak day gas needs in 2023. The nine percent shortfall represents about 149,500 Decatherms per day.

9.2 Please provide a discussion of the 'gas demand response pilot' including to which rate groups it is targeted.

Response:

FEI consulted with ICF to provide the following response.

Con Edison requested approval for a gas demand response pilot program to operate during the 2018/19, 2019/2020, and 2020/2021 winters in Case 17-G-0606. The pilot program was approved with modification by the State of New York Public Service Commission on August 9, 2018. The Commission Order provides an extensive overview of the program.

The pilot program is intended to lead to a reduction in customer net load over a 24-hour period corresponding to the natural gas day. The pilot program is separated into commercial and residential components:

- The commercial DR pilot program will be available to all service classifications, but will be marketed primarily to commercial and industrial customers, as well as multi-family buildings where natural gas is the primary space heating fuel. Participation is limited to 500 customers in the first year, 1,000 customers in the second year, and 1,500 customers in the third year.
- The residential customer DR program will be focused on customer provided internet-communicating thermostats, with 1,000 customers planned to be enrolled by 2021.

[3] ConEdison (2017). 2017 Annual Report. p. 24. URL: http://phx.corporate-ir.net/External.File?item=UGFyZW50SUQ9NDAyNDQ4fENoaWxkSUQ9LTF8VHlwZT0z&t=1&cb=636589031692764246.

The total cost of the DR pilot program is expected to be $5.051 million over three years.

9.3 Please provide an overview of the 'efforts described in [the] filing' to which the above are additional.

Response:

FEI consulted with ICF to provide the following response.

Please refer to the discussion of the Con Edison non-pipelines solutions efforts on page 9 and 10 of the Exhibit B-11 report of Michael Sloan and John Dikeos, ICF.

10. Reference: Exhibit B-11, ICF page 10

> **3.1.4 Review of Northwest Natural Gas Non-Pipes Solutions Efforts**
>
> One natural gas utility that was identified as having looked at the use of geo-targeted DSM for infrastructure deferral as part of our 2017 best practice review is Northwest Natural Gas (NW Natural). NW Natural collaborated with the Energy Trust of Oregon in 2017 to design and implement a geo-targeted load management pilot in Silverton, Oregon.[18, 19] The goal of this geo-targeted pilot was to identify the costs of acquiring peak savings to determine whether projects of this nature can be used as an alternative to physical capacity upgrades. NW Natural noted that there is uncertainty regarding the reliability of peak reductions due to DSM and one of the major challenges the utility faced in the design of this pilot was determining the actual flows for the targeted area due to the number of areas that are served by multiple gate stations.
>
> NW Natural's 2018 IRP, published in August 2018, describes the utility's approach to assessing non-pipe alternatives to infrastructure spending.[20] As part of this process, NW Natural facility planners assess upcoming peak demand shortfalls in their distribution infrastructure and
>
> consider both local peaking assets (e.g. CNG, LNG) and demand side management through additional interruptible customers as potential alternatives to infrastructure spending. As part of the assessment of demand side management alternatives, firm customers with significant annual gas consumption in the targeted areas are engaged to determine if they are willing to pursue interruptible recall agreements. As summarized in the NW Natural's 2018 IRP, the utility recently considered demand side management alternatives, including firm capacity recall agreements, for seven distribution infrastructure projects and was unable to identify sufficient non-pipeline solution options to defer any of the infrastructure projects.[21]

10.1 Please provide the summary for NW Natural's 2018 IRP and/or the section dealing specifically with DSM, including geo-targeted DSM.

Response:

FEI consulted with ICF to provide the following response.

As noted in footnotes 20 and 21 of the Exhibit B-11 report of Michael Sloan and John Dikeos, the two relevant locations are as follows:

- NW Natural (2018). 2018 Integrated Resource Plan, p. 8.8. https://www.nwnatural.com/uploadedFiles/NW%20Natural%202018%20IRP.pdf; and
- NW Natural (2018). 2018 Integrated Resource Plan, p. 8.24. https://www.nwnatural.com/uploadedFiles/NW%20Natural%202018%20IRP.pdf.

11. Reference: Exhibit B-11, ICF page 12

> - **Facilities Planning Requirements:** Electricity facilities are designed to meet instantaneous peak requirements, while gas facilities are designed to meet hourly (distribution infrastructure) and hourly and daily (transmission infrastructure), and daily (gas supply) requirements. These differences in planning time of day tend to increase the value and reduce the cost of reductions in peak demand for the electric industry relative to the gas industry, which makes targeted DSM and DR programs more valuable for the electric industry than for the natural gas industry.

11.1 Please elaborate on how the differences in planning time of day increase the value and reduce the cost of reductions in peak demand for the electric industry relative to the gas industry.

<u>Response:</u>

FEI consulted with ICF to provide the following response.

The instantaneous nature of the peak requirements in the electric industry leads to a lower relative cost for reducing peak requirements since the reduction needs only to occur at the instant of peak demand. Unlike the electric industry, reductions in peak natural gas demand must persist throughout the peak period, either hours, or potentially days, to be effective. This difference applies because natural gas flows slower than electricity and accumulates (i.e. is stored) throughout the natural gas infrastructure which may cause the natural gas system to react more slowly than the electric system to peak demand reduction events.

In addition, an instantaneous peak in demand is likely to exceed average demand by significantly more than peak demand measured over an hour or a day. Hence the same reduction in demand will have a larger benefit for a system if measured on an instantaneous basis which is the case for electric industry.

12. Reference: Exhibit B-11, ICF page 12

- **Cost Structure:** Gas facilities are typically less expensive than electric facilities per equivalent amount of energy delivered (GJ of delivered energy) for a given level of peak energy demand (peak GJ of delivered energy). As a result, utility facility costs typically make up a lower percentage of the typical customer gas bill than for their electric bill. This ultimately leads to the savings associated with a reduction in gas utility infrastructure tending to be lower than the savings available to the electric industry.

12.1 Do utility facility costs typically make up a lower percentage of the customer gas bill than for their electric bill in BC as well? Please discuss and provide quantification, with particular treatment for generation as a commodity with multiple period storage.

Response:

FEI notes that the make up of customers' bills is very different between a gas utility and an electric utility and, therefore, in FEI's view, it is not reasonable to use customers' bills as a comparison between a gas and an electric utility for facility costs.

To respond to the present question, the table below shows the breakdown of the energy costs/power purchase and all other costs for FEI's own natural gas business and for FortisBC Inc. (FBC), FEI's electric sister utility. FEI is unable to comment on BC Hydro's cost structure and the makeup of BC Hydro's customers' bills. The breakdown of customers' bills are similar for FEI and FBC. It is important to note that the cost of gas is currently at a historically low level which influences the portion of cost of gas for FEI. Further, a direct comparison of the cost of energy between FEI and FBC is difficult due to the fact that FBC energy resources are a mix of FBC embedded generation and purchases from a variety of third party sources.

FEI	$000s	%
Revenue (2018 Approved)	1,246,308	100%
Cost of Energy	424,275	34%
All other costs	822,033	66%
Volume (TJ)	228,188	
Reference	BCUC Order G-196-17	

FBC	$000s	%
Revenue (2018 Approved)	356,340	100%
Power Purchase	148,450	42%
All other costs	207,890	58%
Volume (GWh)	3,213	
Equivalent Volume (TJ)	11,567	
Reference	BCUC Order G-38-18	

For the reasons described above, and also the preamble above which is specific about facility costs per equivalent amount of energy delivered (GJ of delivered energy) for a given level of peak energy demand (peak GJ of delivered energy), FEI believes rate base (capitalized assets) per GJ is a better reflection of cost differences between gas facilities and electric facilities. The table below provides a comparison of FEI's 2018 approved rate base per energy delivered versus FBC's 2018 approved rate base per equivalent energy delivered. This shows that, per energy delivered, FBC's rate base is higher than FEI's rate base and is consistent with the statement shown in the preamble above.

	FEI	FBC
2018 Approved Rate Base ($000s)	4,370,603	1,321,217
Rate Base per GJ ($/GJ)	19.15	114.22

13. Reference: Exhibit B-11, ICF page 12

> - **System Outage Risk:** Electric systems are designed to meet a level of system outage risk that is much higher than the system outage risk that is acceptable to natural gas utilities. While system reliability is a critical planning criterion for the power industry as well as for the gas utility, the costs and time period for recovering from a power system outage are relatively modest compared to the costs of recovering from a gas system outage. Unlike an electric utility where the system typically re-energizes itself almost immediately after the issue causing the loss of power is resolved, a gas system relight may take days, weeks or months to resolve due to the need to manually shut off gas flows to each individual meter prior to re-energizing the system, in order to prevent inadvertent gas leaks during the relight process, followed by a manual relight protocol for each individual meter. Insufficient infrastructure could lead to a system shut down during the coldest part of the winter, leaving residential and commercial customers without heat during extremely cold weather.

13.1 The CEC interprets the authors' comments as contending that the use of DSM to defer natural gas infrastructure could result in insufficient infrastructure and increased risk to customers. If so, please provide further details as to the percentage of infrastructure or particularly next increment infrastructure that would need to be deferred to result in such an outcome.

Response:

FEI consulted with ICF to provide the following response.

The excerpt copied into the preamble describes the general risk that must be avoided in planning for a DSM program targeted at peak demand and infrastructure deferral. The risk to customers would arise if both the peak savings from the DSM program did not materialize and the infrastructure to be avoided was not built. However, if the DSM program is implemented and the infrastructure is built, then the risk realized by customers is the cost of the DSM program. The proportion of infrastructure impacted, or in other words the size and cost of the next increment of infrastructure expansion that this risk would apply to would be entirely unique to the infrastructure project that the DSM program was trying to avoid. The increment of cost that would be at risk if the infrastructure were still needed and was built even though the DSM Program was implemented would be entirely unique to the design of the program. Since both considerations are general discussions at this point and neither an avoided infrastructure project nor a DSM program design have been identified, no further detail can be provided.

13.1.1 If not, please clarify.

Response:

Please refer to the response to CEC IR 3.13.1.

14. Reference: Exhibit B-11, ICF page 12-13

> - **Peak Hour Data Availability**: For the electric industry, the need to measure peak period electricity demand has resulted in the availability of electric "smart" meters that record data on a substantially more granular flow level than current natural gas meters. As a result, detailed data on peak period electric demand at the individual customer level is available for the electric industry, and subsequently allows for assurances through data that savings will be realized.
>
>   Gas utility infrastructure planning is also based on peak period requirements (peak hour and peak day requirements). However, unlike the electric industry, there is limited customer level data on peak hour and peak day demand, and almost no data on the impact of DSM programs on peak hour or peak day demand. Most gas utilities'
>
>   customer meters are read no more frequently than once per month, do not record hourly or daily data, and do not measure peak flows.

14.1 How often, and/or at what granularity would natural gas metering need to be in order to provide adequate measurement of peak periods and flow for the effective use of DSM?

<u>Response:</u>

FEI consulted with ICF to provide the following response.

The required temporal resolution and granularity of natural gas metering are related, such that a higher temporal resolution (i.e. more frequent meter readings) would also require a more granular measurement of natural gas consumption since there would be less natural gas consumed in a shorter time period. Based on ICF's analysis for the Enbridge and Union Gas IRP, a natural gas meter capable of hourly measurements may be sufficient though FEI expects that a measurement frequency of 15 minute intervals or better might be required to monitor peak demand impacts.

The volumetric granularity requirements of the natural gas meter may vary by customer type (e.g., residential vs large industrial), with the highest granularity requirements applying to residential customers. Measuring and understanding the impact of residential sector DSM measures on peak demand is critical to the overall success of a geo-targeted DSM program, since the residential sector as a whole was shown to account for 49 and 35 percent of peak hour demand for Enbridge and Union Gas, respectively. For FEI, the residential sector represents about 70 percent of peak hour demand.

ICF's analysis for the Enbridge and Union Gas IRP study estimated that a typical residential customer consumes approximately 0.1 GJ (approximately 2.8 m^3) of natural gas during the peak demand hour. Therefore, the natural gas metering would need to have a granularity of 0.001 GJ (0.028 m^3) in order to show peak hour savings in increments of 1 percentage point for an individual customer. In some instances, it may be possible to meter a group of residential customers; these arrangements would require less metering granularity.

14.2 Are natural gas meters available that can record at such frequency and/or granularity available?

Response:

Please refer to the response to CEC IR 3.4.3.

14.2.1 If so, what is the cost of such a meter, and/or meter reading options? Please explain.

Response:

Please refer to the response to CEC IR 3.4.3.

14.2.2 If the cost of metering is deemed to be prohibitively expensive, please provide rough quantification of the value of the savings relative to the cost of the metering.

Response:

FEI consulted with ICF to provide the following response.

Such a calculation is program and project dependent, as the costs of metering depend on the design of the metering program and the value of the peak demand savings depends on the cost of the infrastructure investment being deferred. As such the requested quantification can not be provided at this time.

15. Reference: Exhibit B-11, ICF page 13

3.3 Conclusions

Despite Mr. Grevatt's claims to the contrary, DSM is not widely accepted as an "emerging best practice" for infrastructure planning. There have been only limited cases where geo-targeted DSM has been implemented for *natural gas* utilities, and no results yet to suggest that this type of effort will ever be considered a utility best practice.

Where DSM has been used, it has been due to special circumstances, including very high cost facilities and challenges in developing new facilities. Furthermore, even in some of the most aggressive jurisdictions, the timeline for implementation of geo-targeted DSM as an alternative to infrastructure investments is not clear.

In the NEEP study authored by Mr. Grevatt and Mr. Neme, the examples presented were focused on infrastructure deferral in the electric power industry. The majority of investments into energy efficiency programs that were discussed in this report were driven by regulatory requirements, or by legislative mandate. The report noted that the electric power experiences are applicable to the natural gas industry; however, as noted in the previous section, there are key differences between the electric power industry and natural gas industry in planning requirements, system outage risks, peak hour data availability, costs and other factors.

There is currently a fundamental disconnect between the limited risk acceptable to natural gas utilities in the facilities planning process and the lack of information on the ability of DSM to reliably reduce peak period demand that will need to be addressed before FEI would be able to rely on DSM to reduce infrastructure investment. These risks are further highlighted in the following section.

15.1 Please identify the 'most aggressive jurisdictions' to which the authors refer.

<u>Response:</u>

FEI consulted with ICF to provide the following response.

Specific jurisdictions that have been ahead of the majority of natural gas utilities on the issues referenced in the preamble of this question include the utilities reviewed in Mr. Sloan and Mr. Dikeos' Exhibit B-11 report and in the ICF Best Practices Review prepared for Enbridge Gas Distribution and referenced in ICF's Exhibit B-11 report. The specific utilities in these jurisdictions include Enbridge Gas Distribution, Con Edison and NW Natural Gas. Please refer to Section 3 in ICF's Exhibit B-11 report for further details about the activities of these jurisdictions.

15.2 Please comment on the activities of these jurisdictions if not already provided either in the evidence or in response to information requests, and indicate where it is located if already provided.

Response:

Please refer to the response to CEC IR 3.15.1.

16. Reference: Exhibit B-11, ICF page 14

4 DSM Infrastructure Deferral Risk Assessment

In his expert evidence, Mr. Grevatt has noted that "FEI's perception that DSM demand measures are inherently too risky for planning purposes is not supported by Con Edison's successful experience in using DSM to defer infrastructure investments".[23] We interpret this conclusion to mean that Con Edison's experience in using DSM to defer infrastructure investments indicates that FEI is incorrect in its perception that DSM demand measures are inherently too risky for planning purposes.

However, there are fundamental differences between Con Edison and FEI that reduce the relevance of the Con Edison experience. The primary difference between FEI and the Con Edison experience is that Con Edison is a combined electric and gas utility throughout the majority of its service territory. As identified in the ACEEE paper referenced by Mr. Grevatt, which was jointly written by authors from Con Edison and from ICF, the Con Edison experience referenced by Mr. Grevatt is based on electric utility experience rather than natural gas experience.

In addition, the Con Edison service territory faces a different set of issues than the FEI service territory. The New York City and surrounding areas served by Con Edison represent one of the most expensive regions in North America to install new infrastructure. As a result, the economics of expansion projects in the Con Edison service territory are expected to be much different from the economics of facilities projects in the FEI service territory.

These differences result in a significantly different planning environment that negates the relevance of the Con Edison electric experience in determining the riskiness of planning to use DSM to defer natural gas infrastructure investments.

Our experience with natural gas utilities supports the perception that the risks of using natural gas DSM to avoid infrastructure investments are not currently well understood and, in most cases, have only begun to be considered by gas utilities and their regulators. Major differences and uncertainty in the planning environments for DSM and infrastructure that impact the risks of using DSM to avoid or defer natural gas infrastructure investments are described in more detail below.

16.1 Please elaborate on the differences between Con Edison's cost structure in installing new infrastructure and that of FEI, and provide quantification of the different costs and how those relate to the cost-effectiveness of geo-targeted DSM.

<u>Response:</u>

FEI consulted with ICF to provide the following response.

A full comparison of the costs of new infrastructure for Con Edison and FEI would require significant effort and access to data that is not publicly available; hence, such an assessment has not been prepared. However, the public data on utility costs provides a compelling indication of the differences between the cost structures of the two utilities.

Con Edison is an urban utility with an aging infrastructure that has been experiencing very rapid growth, with significant new infrastructure investments in a high cost environment. As a result, Con Edison is a high cost natural gas utility. In 2017, Con Edison had US$6.4 billion (U.S.) in rate base, or US$22.70 per thousand dekatherms (Mdth) for a total sales of 282,116 Mdth (alternatively, US$21.50 per TJ for a total sales of 297,632 TJ). The equivalent value for FEI is CA$16.29 per TJ for a 2017 Actual Rate Base of CA$3.727 billion and a total sale volumes of 228,788 TJ.

The higher rate base is reflected in much higher average rates for Con Edison relative to FEI. The average cost for firm transportation, which reflects infrastructure and operating costs, but not natural gas commodity costs was US$7.34 per dth (US$6.96 per GJ) in 2017. The equivalent value for FEI is CAD$1.57 per GJ. Furthermore, the average revenue per dth sold to Con Edison residential customers in 2017 was US$15.35 (US$14.55 per GJ). The equivalent value for FEI is CAD$9.19 per GJ.

16.2 What other issues do the authors identify between Con Edison and FEI, besides the expense to install new infrastructure?

<u>Response:</u>

FEI consulted with ICF to provide the following response.

There are a wide variety of differences between Con Edison and FEI that impact the cost effectiveness of geo-targeted programs:

- Con Edison is a combined electric/natural gas/steam utility that has the opportunity to encourage customers to fuel switch between the three different fuels in order to optimize across the company;
- The age of the existing infrastructure differs by jurisdiction;
- The regulatory structure is unique to each jurisdiction;
- Rates of demand growth differ in the two jurisdictions;
- Weather differs in the two jurisdictions; and
- The customer mix differs between the two jurisdictions.

17. Reference: Exhibit B-11, ICF page 17

> 1. **Changes in the Approval Process for Infrastructure Targeted DSM:** The differences in timeline and risk between DSM achieving annual energy savings and related benefits, and DSM targeted at specific infrastructure investment deferral or avoidance create different planning requirements. Geo-targeted DSM programs designed to reduce peak hour demand will need to be implemented much earlier in the facility planning cycle, often before there is certainty around load growth, and will have limited opportunity for revisions if the programs are not meeting expectations. In addition, the ultimate impacts of the programs – deferral or avoidance of infrastructure investment – will be subject to the general planning uncertainty consistent with the necessary implementation time frame.
>
> As such, DSM programs and technologies targeted at infrastructure deferral or avoidance may need to be subject to a different business and regulatory construct, cost-benefit analysis and different evaluation standards than standard DSM.

17.1 Please discuss the types of business and regulatory construct, cost-benefit analyses, and different evaluation standards that would be appropriate for infrastructure-targeted DSM.

<u>Response:</u>

FEI believes infrastructure-targeted DSM requires further exploration and has not assessed business and regulatory constructs, cost-benefit analyses and evaluation standards for this emerging area of natural gas DSM at this time. As FEI proceeds with further research regarding the potential for infrastructure-targeted DSM, if it is determined that infrastructure-targeted DSM will benefit FEI customers, it will review these areas to assess what is appropriate at that time.

18. Reference: Exhibit B-11, ICF page 17-18

2. **Allocation of Risk:** There is an increase in risk and an increase in cost to the utility of relying on DSM programs as an alternative to infrastructure investment due to the uncertainty regarding the reliability of these programs. This leads to a number of public policy questions:
   - How much risk is appropriate? And how should the risk of underestimating facilities requirements be weighted relative to the risk of overestimating facilities requirements? Is the risk to society of potentially not having the necessary energy services in place an acceptable risk? How would this risk be assessed?
   - Who bears the risk if a geo-targeted DSM program does not lead to a deferral of an infrastructure investment?
   - Who bears the risk if the benefits of a geo-targeted DSM program do not materialize, and the utility pipeline system is insufficient to meet peak demand?

18.1 Please confirm that ratepayers typically bear the risk for DSM-related costs.

<u>Response:</u>

FEI interprets the present question to ask about the financial risk of DSM program implementation. FEI confirms, this financial risk is currently shared across regions and customer classes for FEI's existing DSM programs that are accessible to all customers. In contrast, FEI notes that the risk referred to in the preamble above relates to the reliability of FEI delivering service if infrastructure investments have been deferred as a result of geo-targeted DSM programs but such programs fail to deliver the projected energy and/or peak demand savings. As discussed in the response to BCUC IR 3.80.1, FEI is of the view that increasing risks to system reliability is not acceptable to its customers and its regulators. However, FEI's existing DSM portfolio currently does not include geo-targeted DSM programs. As explained in BCUC IR 3.80.3, the risks and benefits of any potential future geo-targeted DSM initiatives require further exploration.

19. Reference: Exhibit B-11, ICF page 21

> Mr. Grevatt noted that in the 2017 LTGRP "FEI fails to provide a concrete plan and timeline for assessing the potential to use DSM as a cost effective alternative to traditional capacity resources".[26] In the BCSEA response to BCUC IR 1.4.2, "Mr. Grevatt recommends that Commission direct FEI to develop a plan that:
>
> 1) identifies the information that is needed in order to assess the viability of DSM and DR alternatives for deferring infrastructure investments;
>
> 2) describes the approach that FEI will use to obtain the required information;
>
> 3) describes the point in time at which the information will have been obtained; and
>
> 4) describes deliverables and accountabilities associated with the plan."[27]
>
> We do not agree that a specific and detailed Commission directive on this point is needed at this time. Given the lack of certainty surrounding the effectiveness of DSM as an alternative to facility investments and the current lack of any specific major gas infrastructure projects where DSM could be used as an alternative in FEI's service territory in the next several years, the value of directing FEI to develop an accelerated plan is unclear.

19.1 Do the authors believe that such a plan would ever be useful to develop?

<u>Response:</u>

FEI consulted with ICF to provide the following response.

There is a fundamental difference between directing FEI to consider a range of alternatives to traditional capacity resources, and to report back to the Commission on the results of those considerations, vs. directing FEI to develop a plan with specific milestones, schedules, deliverables and accountabilities that can be expected to lead to a time-consuming and expensive review process.

Given the current lack of data on the cost effectiveness of using DSM as an alternative to traditional capacity resources, it is hard to see such a plan resulting in something other than a list of analysis and pilot programs that need to be completed before an assessment of the cost effectiveness can be made with any reliability.

19.1.1 If no, why not?

<u>Response:</u>

Please refer to the response to CEC IR 3.19.1.

19.1.2 If yes, when would the authors recommend such a plan might be undertaken?

Response:

Please refer to the response to CEC IR 3.19.1.

II. CEC INFORMATION REQUESTS TO NAVIGANT CONSULTING INC.

20. Reference: Exhibit B-11, Navigant, page 6

> **2.2.3 Applied more than one approach to screening measure cost effectiveness, including use of the mTRC, to capture the value of avoiding carbon emissions and non-energy and non-monetary benefits**
>
> Mr. Grevatt states in his evidence: "As I noted earlier, RAP suggests that 'policymakers should examine both monetary and non-monetary assumptions' in assessing potential."[20] Application of the mTRC accomplishes this objective of considering the monetary impacts on customer adoption, as well as the value of avoiding carbon emissions and the non-energy and non-monetary benefits that many measures provide customers, but would otherwise not be quantified in the savings estimates.
>
> The regulatory environment for FEI at the time of the analysis allowed the utility to spend up to 33 percent (and currently up to 40 percent) of its entire DSM portfolio on measures or programs that require an mTRC to be cost effective. This approach facilitates the strategic targeting of measures with higher customer acceptance, but less attractive economics, and the incorporation of more DSM into FEI's planning. Thus, the BC CPR analyzed the following three distinct approaches to screening measures for cost effectiveness in recognition of the non-energy benefits that many measures provide customers:
>
> 1. **TRC only:** This case uses the TRC cost effectiveness test across all sectors and presents results consistent with the screening method used in the previous CPR report focusing on technical and economic potential.
> 2. **mTRC only:** This case uses the mTRC cost effectiveness test across all sectors.
> 3. **Hybrid mTRC/TRC:** This case uses the mTRC cost effectiveness test for the residential sector and the TRC cost effectiveness test for the commercial and industrial (C&I) sectors, which is most analogous to FEI's actual DSM program environment.
>
> The effect of assessing these three approaches was to provide a range of possible savings potential under various cost effectiveness environments, where the 'TRC only' case provides a lower bound and the 'mTRC only' case provides an upper bound for savings potential.

> The BC CPR study used the 'hybrid mTRC/TRC' scenario, as specified above, as the foundation for the BC CPR Reference Case. FEI then used the BC CPR Reference Case to inform the 2017 LTGRP Reference Case C&EM analysis. In addition, FEI expanded this potential by using the 'mTRC only'

> scenario as the basis of the C&EM forecast in scenarios subject to the Accelerated outcome of the Non-Price Carbon Policy action critical uncertainty.

20.1 How would Navigant expect the results to change given the allowance of 40% as compared to 33% at the time of assessment? Please explain and provide quantification.

<u>Response:</u>

FEI consulted with Navigant Consulting Ltd. (Navigant) to provide the following response.

FEI's response to BCUC IR 2.61.1 addresses this question in relation to the 2017 LTGRP forecast model which is informed by the BC CPR model results. Similarly to this response, directionally applying a 40 percent mTRC assumption in the BC CPR model itself would likely slightly increase the forecast energy savings and expenditures in the Hybrid mTRC/TRC case. Average TRC benefit/cost ratios for measures included in the portfolio would be expected to drop slightly. However, a full quantification of the impact would require significant additional analysis to determine.

21. Reference: Exhibit B-11, Navigant page 7

2.2.4 Tested a range of incentive sensitivities and determined that the realistic market potential forecast provides a reasonable level of spending

Mr. Grevatt states that the incentive sensitivity analysis “shows that FEI’s Reference Case DSM scenario, based on the CPR Market Potential, does not include all cost effective DSM savings.”[21] However, Mr. Grevatt does not acknowledge in his evidence that, in the BC CPR, there is a diminishing rate of acquired savings per dollar of incentive spending, for incentive levels above those used in the market potential forecast. By testing a range of incentive sensitivities, Navigant determined that the realistic market potential forecast provides a reasonable level of spending on a $/GJ basis for FEI.

As noted previously in FEI’s response to BCSEA IR 2.63.1, the BC CPR has already shown higher savings are possible if FEI increases incentive levels—but at a higher $/GJ cost:

> “Directionally, the BC CPR’s long range forecast and sensitivity analysis indicate that higher incentive levels will likely lead to higher customer participation. However, those higher incentive levels may be more aggressive than the median incentive levels seen throughout North American utilities. Additionally, the sensitivity analysis shows there is a diminishing rate of acquired savings per dollar of incentive spending [emphasis added]. Thus, the BC CPR’s sensitivity analysis shows that higher savings could be achieved, but those savings levels are not necessarily a suitable target for meeting the FEI’s overarching programmatic goals in terms of cost effectively acquiring savings.”

RAP acknowledges this effect by stating: “Given that the marginal value of each dollar may vary, the magnitude of the change in savings may not be directly proportional to the magnitude of the change in the portfolio budget.”[22]

Ultimately, the impact from a higher level of incentive spending may translate to increased customer rate impacts.

21.1 Please discuss the relevance of the statement that ‘…those incentive levels may be more aggressive than the median incentive levels seen throughout North American utilities’.

Response:

FEI consulted with Navigant to provide the following response.

This response also addresses CEC IR 3.21.2.

The higher incentive levels (as a percentage of incremental measure costs) assumed in the sensitivity analysis may be greater than the median value for North American utilities, likely resulting in a lower savings rate per incentive spending relative to common practice. FEI is uncertain what threshold CEC uses when determining whether a practice is “problematic”. Nevertheless, FEI believes that more aggressive incentive levels than other jurisdictions should be based on sound evidence that supports the higher incentives as they likely would result in increased ratepayer costs. When setting incentive levels, a utility should also consider its program and market-specific operational program delivery factors and its programmatic goals.

These latter two items are more akin to program design so FEI did not account for them in the 2017 LTGRP. However, the 2017 LTGRP C&EM analysis is informed by the BC CPR results that, in turn, are informed by Navigant's calibration to FEI's historical C&EM program performance.

21.2 Would it be problematic for FEI to have more 'aggressive' incentive levels than other jurisdictions? Please explain.

Response:

Please refer to the response to CEC IR 3.21.1.

21.3 Please provide quantification for the diminishing rate of acquired savings per dollar of incentives, or identify where this is already provided in the evidence.

Response:

FEI consulted with Navigant to provide the following response.

Please see Section 4.2.3.5 of the Exhibit B-1 for quantification of the diminishing rate of acquired savings per dollar of incentives.[4]

21.4 Please comment on the potential difference between Greenhouse Gas Emission Reduction seriousness in the BC policy environment and that of other jurisdictions in North America, and particularly contrast the current US administration's GHG policy direction.

[4] Application, pp.121-123.

Response:

FEI has not conducted any comprehensive comparison of GHG policy seriousness across jurisdictions in North America. FEI notes that BC's regulatory framework is the standard by which DSM activities are evaluated in British Columbia.

21.5 Please confirm, or otherwise explain that the stricter the future for GHG reduction policy the more valuable natural gas DSM will become.

Response:

FEI consulted with Navigant to provide the following response.

FEI interprets the value of natural gas DSM in this context to mean the monetary benefits of DSM initiatives as defined in the cost effectiveness tests that are indicated by BC's DSM regulatory framework. Not confirmed, GHG reduction policy could take many forms and the specifics will determine the value of natural gas DSM. For example, increased carbon tax rates could increase the avoided cost of gas that is applied to the cost effectiveness tests, whereas stricter minimum energy performance standards could reduce the DSM energy savings that are used for cost effectiveness testing.