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VIA COURIER, EMAIL, and RESS

November 26, 2018

Ms. Kirsten Walli
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 26th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Enbridge Gas Distribution Inc. ("Enbridge" or the "Company")
Ontario Energy Board ("Board") File No.: EB-2018-0097
Bathurst Pipeline Project – Interrogatory Responses

In accordance with the Board's Procedural Order No. 2 for the above noted proceeding, enclosed please find the interrogatory responses of Enbridge.

For reference, the interrogatories from OEB Staff and SEC have been re-numbered to be in order of sequence with the previous filed interrogatories.

Please contact the undersigned if you have any questions.

Sincerely,

(Original Signed)

Bonnie Jean Adams
Regulatory Coordinator

cc: EB-2018-0097 Intervenors

STAFF INTERROGATORY # 11

INTERROGATORY

Ref: I.EGDI.SEC.1, Attachment 2

Preamble:

Enbridge Gas Distribution Inc. (Enbridge) provided a copy of an internal briefing it says is from May 2018. The briefing does not include a cover page, title or date.

Questions:
a) If there is an existing cover page to the briefing, please file it.
b) If the briefing is an excerpt from a larger report, please file the larger report in full.
c) What prompted the preparation of the briefing? Who requested it?

RESPONSE

a) There is no cover page to the briefing. However, in the process of converting the internal briefing into its final format for submission to the Board the document header was removed in error. Please find attached to this interrogatory the first page of Exhibit I.EGDI.SEC.1 Attachment 2 inclusive of the document header and date.

b) The briefing constitutes the entire briefing. There is no larger report.

c) It was recognized that the ICF IRP Report showed that geo-targeted DSM may be able to defer the Project at the time the study was initiated. However, given that the demand forecast provided to ICF no longer reflected the best available information it seemed relevant to document the change and the high level analysis which demonstrated that deferral of the project was no longer an option. The briefing was requested by the Manager, Carbon Strategy for the purposes of documentation and sharing with the IRP Steering Committee.

IRP Study Report Findings - Bathurst Reinforcement LTC Briefing

May, 2018

The purpose of this document is to provide a summary of a finding from the IRP Study Report regarding the viability of Demand Side Management (DSM) to be a cost effective alternative to an infrastructure project. The project in question known as "Case Study #1" in the IRP Report is the Bathurst LTC.

Background:

- **The IRP study used several actual reinforcements from EGD and UGL portfolios to test the high-level models developed for the study based on insights and costing related to the Natural Gas's Achievable Potential Study from 2016.**

- **The reinforcements were selected by the Utilities and designed to determine the 'best case' option for targeted DSM to be effective (i.e. if it can't work in the best case, it cannot work elsewhere).**

- **The reinforcement evaluated in Case Study 1 was an EGD CDA area reinforcement and was provided with long term Hemson growth forecasts. The LTC is now being developed and is using updated localized and current growth forecasts.**

Passage from IRP Study:

"Case Study 1: Geo-Targeted DSM Costs Less than Planned Facility Investments

Exhibit 104 presents the geo-targeted DSM supply curve for a distribution system located in Enbridge's Central region, where 48% of the peak hour demand is attributed to residential customers, and the remaining 52% to commercial customers. The current peak hour demand from the distribution system is approximately 30,000 m^3/h and is growing at an average rate of 158 m^3/h per year (or 0.5%). Based on information provided by Enbridge, the peak hour demand growth will need to be accommodated by a facility investment project that is anticipated to have a capital cost of approximately $8,200,000 for the installation of 3.2 km of an NPS 12 steel high-pressure pipeline.

For this case study, geo-targeted DSM appears to be a cost-effective. This result is shown in Exhibit 104, where it can be seen that the PV of the planned facility investment project is approximately $6.7M, while it is estimated that a geo-targeted DSM program can provide the necessary annual peak hour demand savings of 158 m^3/h for a PV cost ranging somewhere between $3.7M and $4.9M.[1]

The cash flows for each scenario are displayed in Exhibit 105, where it can be seen that annual expenditures of $379,000 on geo-targeted DSM until 2033 would result in a total PV cost of ~$4.3M while maintaining the peak hour demand below the capacity of the existing distribution pipeline.

[1] This range of geo-targeted DSM program costs corresponds to the points on the green line and the red line along the vertical dotted line corresponding to 158 m^3/h.

STAFF INTERROGATORY # 12

INTERROGATORY

Ref: Exhibit D, Tab 2, Schedule 1, page 1
I.EGDI.SEC.1, Attachment 1, page 1
I.EGDI.SEC.1, Attachment 2, pages 1 and 3

Preamble:
In its application, filed August 1, 2018, Enbridge estimated the total project cost to be approximately $9.15 million. The briefing contains a quote from the January 2018 Natural Gas Integrated Resource Planning (IRP) study prepared by ICF. The quote indicates that the estimated total project cost was approximately $8.20 million. The briefing contains a table in the results section that indicates the total project cost to be approximately $9.9 million.

Question:
Please reconcile the three estimated total project costs.

RESPONSE

As the demand forecasts are updated to reflect the best available information concerning future demand growth detailed capital budgets also become more refined the closer it is to the Company making a final investment decision. The slight change in budget over the three documents referenced is an example of the impact of the process required to insure that the final capital budget is in alignment with the finalized demand forecasts and the project scope, all in accordance with the Company's project governance standards. Each of the above noted project costs were reasonable estimates at the time that they were made based on the forecasts and project scope contemplated at that point in time.

STAFF INTERROGATORY # 13

INTERROGATORY

Ref: I.EGDI.SEC.1, Attachment 2, page 1

Preamble:
The briefing contains a quote from the IRP Study Report prepared by ICF. In part, the quote says, “Exhibit 104 presents the geo-targeted DSM supply curve for a distribution system located in Enbridge’s Central region, where 48% of the peak hour demand is attributed to residential customers, and the remaining 52% to commercial customers.”

Questions:

a) OEB staff is unable to locate this quote in the ICF report filed as Exhibit I.EGDI.SEC.1 Attachment 1. Is this because only the executive summary of the IRP Study Report was filed? In any case, please file the complete IRP Study Report.

b) Please discuss the methodology Enbridge used to determine the attribution of peak hourly demand between residential and commercial customers within Enbridge’s central region and how applicable that finding is to the customer mix in the revised Project area.

RESPONSE

a) The IRP Executive Summary filed in this hearing in response to SEC Interrogatory #1, found at Exhibit I.EGDI.SEC.1, Attachment 1 provides a synopsis of the body of material from the complete IRP Report. A copy of the full IRP Report is filed as Attachment 1 to this interrogatory response. This document, which is 246 pages in length, demonstrates the detail and extent to which DSM has been considered as a possible IRP tool. While there is substantial material regarding IRP which may be of assistance to the Board in considering the future role of DSM in the context of IRP, most of the full report is not relevant to the Project generally nor the 2 issues identified by the Board in Procedural Order No. 2. To the degree that the Board and interested parties wish to engage in a comprehensive review and discussion of the Report in its entirety, including those portions which may not prove directly relevant to this proceeding, the Company is hopeful that such discussions can be facilitated in a more appropriate venue such as the standalone consultation regarding IRP proposed by Enbridge in its Reply Submission.

b) Enbridge did not allocate peak hourly demand between residential and commercial customers within the study; this analysis was performed by ICF. Please see ICF’s updated analysis in the response to OEB Staff Interrogatory # 20, found at Exhibit I.EGDI.STAFF.20, Attachment 1.

ICF

FINAL REPORT

Natural Gas Integrated Resource Planning:

Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment

May 18, 2018

Submitted to:
Enbridge Gas Distribution, Inc. & Union Gas Limited

Submitted by:
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Table of Contents

List of Exhibits

Terms of Reference

This study employs numerous terms that are unique to analyses such as this one and consequently it is important to ensure that readers have a clear understanding of what each term means when applied to this study. Below is a brief description of some of the most important terms:

Achievable Potential	The achievable potential is a subset of the economic potential. It takes into account realistic market penetration rates of cost-effective measures over the study period based on a number of factors. These include market barriers, customer preference, and acceptance of payback periods, return on investment (ROI) and investment hurdle rates.
Aggressive Scenario	This is an achievable potential scenario for the development of DSM supply curves. This scenario reflects the incremental demand savings based on high incentive levels.
Avoided Costs	The marginal cost avoided by society through a reduction in energy usage (electricity or natural gas). Distribution avoided costs are the marginal costs to infrastructure that are avoided by a reduction in energy usage. Gas avoided cost is the marginal cost of gas supply that is avoided through a reduction in energy usage.
Avoided Capital Costs	The avoided costs of facility investments resulting from the offset of peak demand growth by DSM.
Base Year	This is the starting point for the analysis. The base year provides a detailed description of "where" and "how" natural gas is used in each sector. The bottom-up profile of energy use patterns and market shares of energy-using technologies was calibrated to Union Gas and Enbridge Gas Distribution customer sales data. The base year for this study is calendar year 2014.
Business as Usual (BAU) Scenario	This is an achievable potential scenario for the development of DSM supply curves. This scenario reflects the demand savings that can be achieved based on modest incentives.
City Gate Station	Location where gas is continuously metered into a downstream system.
Cost of Service	Reflects the total amount that must be collected in rates for the utility to recover its costs and earn a reasonable return.

Curtailment	The reduction of gas deliveries due to a shortage of supply or because demand for service exceeds a pipeline's capacity.
Customer Data	Customer data, in the context of this report, refers to the 2014 hourly metered data for contract rate power producers and industrial customers (where available) that was provided to ICF by the Gas Utilities.
Deferral, active	DSM programs that target peak hour and peak day demand reductions in a given area where specific facility investments are planned. The targeted DSM program results in the facilities being downsized or deferred.
Deferral, passive	The deferral of new infrastructure investment as a result of implementing broad-based DSM programs, whether or not the programs are specifically designed to reduce peak hourly or daily demand.
Demand Response (DR) Programs	Programs designed to incentivize consumers to reduce or shift their energy usage during peak periods in response to time-based rates or other forms of financial incentives provided by utilities.
Demand Side Management (DSM) Programs	Encourage consumers to modify their level and pattern of energy usage, and consist of planning, implementing, and monitoring a utility's activities. **Broad-based DSM programs** are marketed to a large portion of the consumer base. **Geo-targeted DSM programs** are targeted to specific locations.
Design Day	The day on which demand for natural gas within a utility's service territory is greatest, and the standard by which the transmission and distribution pipeline systems and other gas supply transportation requirements are planned.
Discount Rate	The interest rate used to calculate the present value of expected yearly benefits and costs.
Distribution System	In the context of this study, refers to the network of pipelines that are modelled using steady state analysis.
DSM Supply Curve	A graph that depicts the volume of energy at the appropriate screened price in ascending order of cost effectiveness.

Economic Potential	The economic potential is the total natural gas consumption or demand savings resulting from the implementation of all measures included in the technical potential, and which also pass the cost effectiveness screening, regardless of market acceptance.
End-Use	The services of economic value to energy users. For example, space heating is an end-use; natural gas sold to an office tenant is of no value without the equipment necessary (furnaces, boilers, etc.) to convert it into thermal energy.
Facilities Planning	The facilities planning process is based on a long-term growth forecast intended to identify potential incremental facility requirements, and to develop investment plans prior to the need for new facilities. Its primary goal is to ensure that the utility infrastructure is of sufficient size and installed at the appropriate/required time to provide reliable natural gas service at the design day condition, and consistent with reasonable costs.
Gas Utilities	Refers jointly to the Ontario natural gas systems of Union Gas Ltd. and Enbridge Inc.
Gate Station Data	Hourly measure of total gas flow through utility city gate stations.
Hours-Use Factor	The factor used to allow for the conversion of annual consumption values (m^3/yr.) to peak demand values (m^3/h) for each of the peak periods considered.
Integrated Resource Planning (IRP)	IRP for natural gas utilities is an expanded method of planning, whereby the expected demand for natural gas services is met by the least costly mix of supply additions, energy conservation, energy-efficiency improvements, and load management techniques (i.e., the integration of supply side resources and demand side resources). Specific objectives of IRP are to continue to provide reliable service, equity among ratepayers, and a reasonable return on investment for the utility, while addressing environmental issues and achieving the lowest cost to the utility and the consumer. ▪ **Note:** Although this study is referred to as an IRP study report, it does not meet the definition of a conventional integrated resource plan. This report is an initial assessment focusing on the relationship between Demand Side Management (DSM) and facilities planning.

The integration of supply and demand side planning efforts will be influenced by the results of this study for future facilities planning efforts.

IRP Intersection #1

The intersection between broad based DSM programs and the distribution infrastructure planning process.

IRP Intersection #2

The intersection between geo-targeted DSM programs and distribution infrastructure planning for subdivisions and new communities.

IRP Intersection #3

The intersection between geo-targeted DSM programs and distribution infrastructure planning for system reinforcement projects.

Line pack

A phenomenon for allowing more gas to enter a pipeline than is being withdrawn, thus increasing the pressure, or “packing” more gas into the system. The packed gas is drawn down, to meet peak period demand requirements. The draw down is referred to as “drafting.”

Load Profile

The time pattern and magnitude of natural gas demand. For this study, the following types of load profiles were developed:

General Load Profiles: Created using 2014 hourly utility gate station data and industrial customer meter data provided by the Gas Utilities. General load profiles were created separately for: (i) the industrial sector (not including power producers), and (ii) a combination of residential and commercial sectors.

End-Use Load Profile: Hourly load profiles created for each combination of sub-sector and end-use (e.g., an hourly load profile was created for the space heating end-use in the Offices sub-sector).

The end-use load profiles were further applied specifically to each measure, depending on whether the measure followed a uniform or non-uniform savings profile. See definitions of Uniform Savings Profiles and Non-Uniform Savings Profiles for more information.

Representative Design Day Load Profile: General and end-use load profiles created to represent the load profile of natural gas demand during a representative design day.

Measure

Any type of technology, project, or activity that is designed and implemented to reduce the consumption of energy in a building.

Measure Total Resource Cost Plus (TRC-plus) Test	A cost/benefit analysis of the net present value of energy savings that result from an investment in an efficiency or fuel choice technology or measure. The measure TRC-plus calculation considers a measure's full or incremental capital cost (depending on application), plus any change (positive or negative) in the combined annual energy and operation and maintenance (O&M) costs. This calculation uses the avoided natural gas price with a 15% non-energy benefit adder,[1] electricity supply costs, the life of the technology, and the selected discount rate.
No Impact on Peak	Some measures do not coincide with peak, due to the savings occurring outside of the peak day, or any of the peak hours within the morning lift of 7 a.m. to 10 a.m. (peak periods #1-4). These measures are referred to as measures with "no impact on peak"; e.g., a high-efficiency pool heater applied to an outdoor pool. It was not necessary to develop a load profile for the savings from these measures.
Non-uniform Savings Profile	A custom load profile developed for measures in which the savings were not uniformly distributed. Non-uniform savings profiles were developed based upon estimates of how the measure savings were distributed. Custom scaling curves were developed in order to do this. See definition of Scaling Curve for more information.
Peak Demand	Peak demand is the maximum natural gas use required by a customer during a short time period, typically one hour.
Peak Demand Savings	The vast majority of measures reduce peak demand since at least a portion of their savings coincide with the peak. Depending on the period under consideration, a reduction in peak demand is referred to in this report as either "peak period demand savings" or "peak hour demand savings".

[1] The 15% adder accounts for the non-energy benefits associated with DSM programs, such as environmental, economic, and social benefits, as selected by the OEB in 2015-2020 DSM Framework. It is aligned with the cost-effectiveness test used by the IESO, as per the Minister of Energy's Conservation First Framework.

Peak Demand Increase

The savings from a small number of measures, such as adaptive thermostats, do not coincide with peak.[2] Furthermore, these measures were found to actually increase energy natural gas consumption during certain peak hours. It should be noted, however, that these measures still provide natural gas savings when the peak day is considered in aggregate, and may still provide demand savings during hours surrounding the peak hour.

An increase in peak demand is referred to as a "peak period demand increase" or "peak hour demand increase", depending on the peak period under consideration.

Peak Hour

The "peak hour" or "peak period of interest" for the Gas Utilities is from 7 a.m. to 8 a.m. This is the peak period at which the maximum peak demand occurs at a utility system-wide level.

Peak Period

The time at which peak demand occurs (usually the peak hour of the day or peak day of the year). The DSM impacts analysis was focused on four (4) peak hour periods for distribution infrastructure (peak demand periods #1-4), which included each hour between 6 a.m. and 10 a.m., collectively referred to as the morning lift.

Program Costs

The costs to develop the DSM supply curves are composed of both incentive and non-incentive costs.

Incentive costs are based on the estimated level of incentive required to influence DSM measure adoption.

Non-incentive costs are administrative costs for DSM program delivery activities, including items such as marketing and staff.

Reference Case

A projection of natural gas consumption from 2015 to 2030 that includes natural conservation (which would already occur, even in the absence of DSM programs), but no impacts of utility DSM programs. The reference case is based on the 2014 base year and the Gas Utilities' load forecasts, and is the baseline against which the scenarios of natural gas consumption savings and demand savings are calculated.

[2] Adaptive/smart thermostats are also an example of a measure that could be used within the context of a demand response program in order to reduce peak hour demand over the morning lift period.

Scaling Curve	Used for the scaling of end-use or measure load profiles to estimate the distribution of natural gas savings. The scaling was driven by relationships between factors such as building type, occupancy, and/or weather.
Sector	A group of customers with common economic activities. This study includes residential, commercial, and industrial sectors.
Sub-Sector	A classification of customers within a sector by common features. Residential sub-sectors are defined by type of home (e.g., detached or attached). Commercial sub-sectors are generally defined by type of commercial service (e.g., retail or office). Industrial sub-sectors are defined by process (e.g., heavy process, mineral processing, etc.).
Technical Potential	The total natural gas consumption or natural gas demand savings resulting from the implementation of all technically feasible energy-efficiency measures, regardless of cost effectiveness or market acceptance.
Transmission System	In the context of this study, refers to portion of the pipeline system that are modelled using transient analysis.
Uniform Savings Profile	A profile that matches the end-use load profile to which the measure applies. For example, the distribution of energy savings resulting from a building envelope measure (e.g., attic insulation) would likely follow the space heating load profile. This type of measure was assigned a uniform savings profile, (i.e., the savings profile uniformly maps to the end-use profile).
Utility Data	In this context, utility data refers to any 2014 hourly gas flow data provided to ICF by the Gas Utilities, and includes both gate station data and customer data.

Executive Summary

1. Introduction, Scope and General Conclusions

1.1 Introduction

Integrated Resource Planning (IRP) has been considered in the regulatory environment in Ontario since the early 1990s. Between 1995 and the present, the gas utilities in Ontario have engaged in Demand Side Management (DSM) activities which have generated significant natural gas savings across all rate classes as well as likely provided passive infrastructure investment savings by reducing demand in a broad-based context.

Recently, the role of geo-targeted DSM programs in the infrastructure planning process was raised during the EB-2012-0451 proceeding as part of the review of the Enbridge GTA Reinforcement Project. The Board followed up on this question in the 2015-2020 DSM Framework issued by the Board on December 22, 2014. In this decision, the Board directed the:

> Gas utilities to each conduct a study, completed as soon as possible and no later than in time to inform the mid-term review of the (2015-2020) DSM Framework.[3]

Further, the Board stated that it:

> Expects the gas utilities to consider the role of DSM in reducing and/or or deferring future infrastructure investments far enough in advance of the infrastructure replacement or upgrade so that DSM can reasonably be considered as a possible alternative.[1]

Enbridge included a proposed study scope in EB-2015-0049. The study scope was designed to evaluate the potential to use DSM to avoid or defer (reduce) infrastructure costs through 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.

The study scope was reviewed by interveners and ultimately approved by the Board in the DSM Multi-Year decision. Enbridge Gas Distribution and Union Gas Limited ("the Gas Utilities") jointly engaged ICF to conduct this study.

This executive summary provides an overview of the primary considerations and conclusions reached by ICF during the course of the study.

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[3] OEB, Report of the Board: Demand Side Management Framework for Natural Gas Distributors (2015-2020), pg. 36, Dec. 22, 2014, available at: https://www.oeb.ca/sites/default/files/uploads/Report_Demand_Side_Management_Framework_20141222.pdf

1.2 Overview of Study Scope

Given the ultimate goal of identifying a process to ensure that DSM is considered as an option to avoid, defer or reduce ("reduce") infrastructure investment costs, the study attempted to identify the barriers to using DSM as an option, and to propose processes to address and overcome these barriers.

The scope of the study included the following items:

1. ***Review of Industry Experience*: ICF conducted a literature review in which it evaluated how other leading utilities address issues related to broad-based DSM and facilities planning and issues related to the impact of DSM programs on sub-division and new community planning. ICF also reached out to and interviewed leading North American utilities identified as having experience working on integrated resource plans
2. ***Assessment of DSM Impacts on Peak Hour and Peak Period Requirements*: ICF leveraged the results of the 2016 OEB Conservation Potential Study (OEB CPS)[4] and developed load profiles and hours-use factors to estimate the winter peak period demand breakdown and the achievable winter hourly peak demand reduction from DSM for the Gas Utilities. ICF also developed DSM supply curves to assess the costs of DSM implementation against the demand saving impacts.
3. ***Application of DSM Supply Curves to Facility Investments*: ICF leveraged the results of the DSM impacts analysis to understand the potential of DSM programs to defer infrastructure investments (i.e. delay the need for additional capacity for new construction and reinforcements projects). As part of this step in the process, ICF worked with utility staff to identify appropriate hypothetical case studies based on specific examples of utility infrastructure investments. Information from these case studies that fed into the analysis included project costs, current and forecasted capacity requirements, and the distribution of energy consumption by facility type. The DSM supply curves developed in step 2 were used to compare the costs of peak demand reduction through the implementation of DSM against infrastructure project costs.
4. ***External Review and Stakeholder Engagements*: Throughout the IRP study, ICF and the Gas Utilities consulted with a Study Advisory Group (SAG) in order to gain insights on IRP processes for similar utilities and to discuss the study approach and findings. The SAG was made up of members from other North American gas utilities, the Independent Electricity System Operator (IESO), the academic community, as well as an observer from the Ontario Energy Board Staff. The study has benefited from the hands-on experience of staff in other organizations that have undertaken system-wide Resource Planning. This external review has brought a broad perspective to the study and helped to ensure the quality of the study across the several specialized fields involved.
5. ***Transition Plan*: The OEB directed Enbridge and Union to work jointly on the preparation of a proposed transition plan that outlines how to include DSM as part of future infrastructure planning activities within the Utility Planning Process. This ICF study provided critical insights used by the Gas Utilities during the development of the Utilities' Transition Plan.

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[4] ICF, Natural Gas Conservation Potential Study: Final Report, completed on behalf of the Ontario Energy Board (OEB), July 7, 2016, available at: https://www.oeb.ca/oeb/_Documents/EB-2015-0117/ICF_Report_Gas_Conservation_Potential_Study.pdf

The Transition Plan will be filed with the OEB by the Gas Utilities as a companion document to this report.

1.3 Study Highlights

ICF's review of existing DSM programs at North American gas utilities in other jurisdictions found that little to no activity has been undertaken to directly reduce transmission and distribution costs using targeted DSM and Demand Response (DR). In addition, ICF found that the measured data on hourly natural gas consumption necessary to determine the potential impacts of DSM on new facilities requirements is generally unavailable.

ICF also assessed activity in the electric power industry. However, differences in utility cost structure, duration of peak period requirements, and availability of data on DSM impacts lead ICF to the conclusion that geo-targeted DSM programs are likely to be more cost-effective for the electric industry than they are for the natural gas industry, and that the electric industry experience provides only relatively limited value as an example for the gas industry.

Due to the lack of industry experience, and the lack of measured data on DSM peak period load impacts, ICF conducted most of the research into the potential for DSM to impact infrastructure requirements by extrapolating existing data on DSM program impacts from annual data to peak hourly period data based on building modeling, and other theoretical analysis. While ICF views the analysis as robust, there remains significant uncertainty, particularly on the cost and reliability of using DSM to reduce infrastructure investment. Hence, our conclusions should be treated as preliminary until additional research is completed.

1.3.1 Highlights

A more detailed discussion of ICF's general conclusions from this study are reviewed in Section 8 of this executive summary. Highlights from the study are summarized below.

1. Based on ICF's initial assessment of the potential to reduce peak hour demand using DSM, it appears possible that some infrastructure investments may be reduced through the use of targeted DSM.
    a. While there is little to no measured data on actual peak hour impacts of DSM programs, ICF's analysis indicates that many, but not all, DSM measures should be expected to have measurable impacts on peak hour natural gas demand.[5]
    b. ICF's analysis suggests that geo-targeted DSM programs would have the potential to offset demand growth by up to about 1.24 percent per year, before consideration of DSM program and measure costs.
    c. Opportunities to reduce facility investments through the use of geo-targeted DSM are likely to be limited due to the cost of geo- targeted DSM programs relative to the cost of the infrastructure, as well as the maximum penetration rate of DSM programs, which appears likely to be lower than the rate of growth in areas where a significant share of new infrastructure projects are indicated.

[5] The clearest example is the inclusion of adaptive thermostats in DSM programs, which account for a significant amount of potential annual energy savings available through DSM programs, but appear likely to increase peak period infrastructure requirements.

2. ICF's review indicates that changes in Ontario energy policy and utility regulatory structure would be necessary to facilitate the use of DSM to reduce infrastructure investments. These include:
    a. Cost recovery guidelines for overlapping DSM and facilities planning and implementation costs, and criteria for addressing DSM impact risks.
    b. Approval to invest in, and recover the costs of the Advanced Metering Infrastructure (AMI) necessary to collect hourly data on the impacts of DSM programs and measures.
    c. Changes in the approval process for DSM programs to be consistent with the longer time frame associated with facilities planning.
    d. Clarification on the allocation of risk associated with DSM programs that might or might not successfully reduce facility investments.
    e. Guidance on cross subsidization and customer discriminations inherent in geo-targeted DSM programs that do not provide similar opportunities to all customers.
    f. Guidance on how to treat conflicts between DSM programs designed primarily to reduce investment in new infrastructure and DSM programs designed to reduce carbon emissions or improve energy efficiency.
    g. Guidance on how to treat uncertainty associated with energy efficiency programs outside the control of the Utilities that impact peak period demand.
3. ICF's review indicates that changes in utility planning processes would be necessary to facilitate the use of DSM to reduce infrastructure investment.
    a. Facilities planning is based on an avoidance of risk due to the potential consequences associated with the lack of necessary infrastructure, while DSM program design does not generally need to address similar concerns. The differences in risk profiles create significant challenges in incorporating DSM programs into the facilities planning process.
    b. Geo-targeted DSM programs will need to be implemented during the early stages of the facilities planning cycle in order to maximize the impact of the geo-targeted DSM programs and to facilitate risk management if the DSM programs do not meet objectives.
    c. Other differences between the DSM and facilities planning process within the utilities that must be reconciled include differences in asset lifetimes, cost-effectiveness criteria, and program assessment and planning timeframes.

1.3.2 Recommendations for Additional Analysis

Overall, there is currently a fundamental disconnect between the limited risk acceptable to the 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 the Utilities would be able to rely on DSM to reduce infrastructure investment:

- The lack of measured data on the actual impacts of DSM measures on peak period demand increases the risk (hence the cost) of using DSM to reduce infrastructure investments.
- The lack of reliable program implementation cost data for geo-targeted DSM programs makes accurate cost comparisons between facilities and DSM unavailable.

- The maximum market penetration rate for geo-targeted DSM programs limits the number of infrastructure projects where geo-targeted DSM programs should be considered as an alternative to infrastructure projects to low growth market areas.

As a result, additional research and additional hourly data by way of additional metered hourly reads (i.e. automated meter reading or infrastructure installation (AMI), as well as pilot studies to determine the cost-effectiveness and implementation potential of DSM programs are necessary before the Gas Utilities would be able to rely on DSM to reduce new infrastructure investments as part of the standard facilities planning process.

2. Review of Industry Experience

ICF conducted a literature and best practices review process in which it evaluated how other leading North American utilities address issues related to DSM and facilities planning, and issues related to the impact of DSM programs on sub-division and new community planning. The following subsections discuss other gas utility experiences using DSM to defer infrastructure investments and the differences found between natural gas and electric utilities' planning processes.

2.1 Utility Experience Using DSM to Defer Infrastructure Investments

As part of the review of the potential for DSM to reduce the need for infrastructure investment, ICF conducted a literature and best practices review across many North American jurisdictions to assess the state of the industry. The review focused on experience using DSM and demand response (DR) programs to reduce the need for infrastructure investment. ICF also included a review of the electric utility experience utilizing energy efficiency[6] and DR in the facilities planning process.

Based on a review of the state of the industry, there is no relevant precedent for, or evidence of natural gas utilities consideration of the impact of broad-based DSM, geo-targeted DSM or dedicated DR programs impact on facilities planning. Further, while electric utilities have used DSM and DR programs to reduce the need for new generating capacity and transmission capacity for many years, there is only relatively limited experience deferring distribution system infrastructure.

ICF's review of existing energy efficiency programs at other North American gas utilities found that several other natural gas utilities have started looking into the potential impact of DSM programs on system infrastructure requirements. However, these efforts remain in the very early stages. As such, there has been much less progress on the gas side as compared with the electric power industry. Furthermore, ICF did not identify a natural gas utility in any other jurisdiction that is currently using geo-targeted DSM programs to actively avoid investing in infrastructure in specific areas. In fact, of the utilities ICF spoke to, only NW Natural Gas is planning a geo-targeted DSM program, which they are planning to implement through a pilot study.

ICF was also unable to identify any natural gas utilities outside of Ontario that explicitly consider the impact of DSM programs on peak hour or peak day demand. Rather, savings from DSM programs were found to be focused on annual savings and impacts of DSM on infrastructure planning are assessed as annual demand reductions, rather than the peak hour or peak day requirements that drive the facilities planning process.

Gas utilities in other jurisdictions expressed concerns about the reliability of the DSM impacts as an infrastructure investment alternative due to the lack of information, and metered data on the

[6] Electric utilities in Ontario refer to energy efficiency as Conservation and Demand Management (CDM) but energy efficiency is typically referred to as Demand Side Management (DSM) by most electric and gas utilities across North America (i.e. including the natural gas utilities in Ontario). For purposes of this report, all traditional annually focused DSM is referred to as energy efficiency or DSM, whether pertaining to electricity or natural gas. The terms have been used interchangeably.

impacts of DSM on peak hourly demand. This is compounded by the fact that peak savings for DSM programs have not previously been tracked, although some jurisdictions are beginning to address this. For instance, Energy Trust of Oregon is tracking peak hour savings from DSM on behalf of NW Natural and Questar Gas was asked to consider the peak hour impacts of DSM measures such as tankless water heaters. Questar Gas is developing a framework to consider positive and negative peak impacts due to DSM.

ICF's review of gas industry DSM plans indicated that the estimated costs of peak day gas supply are commonly included in the avoided cost estimates used to assess the value of DSM programs. DSM is expected to reduce peak day requirements, leading to reduced need for peak day gas supply resources. Furthermore, avoided costs used to value DSM programs generally include estimates for infrastructure investment costs. These adders to the avoided costs are specific to the region in which the natural gas utility conducts business. Although they are appropriate for passive system-wide deferral from non-targeted DSM, they are generally small relative to the total avoided cost. ICF's review also found that, while the value of infrastructure investment is typically considered in the cost-effectiveness tests of DSM programs, the impact is not based on the assessment of individual infrastructure projects.

Planning staff at the utilities with whom ICF spoke expressed concerns related to leveraging DSM to defer infrastructure investments. Most of the concerns were related to the following items:

- **Reliability:** The reliability of peak hour reductions due to DSM investments
- **Lack of metered data:** Most utilities are able to identify peak hourly data only at a system gate station level and further granularity is limited. Advanced metering would be required in order to substantiate peak hour reductions from geo-targeted IRP. Questar and NWNG noted that they are considering additional metering as part of their work in the area.
- **Changing lead times for projects:** Planning staff from the other utilities indicated that a minimum lead time of 5 years is required to incorporate geo-targeted DSM. They noted that large customers can have disproportionate impacts on the demand on a network and the timing for additional capacity requirements.
- **Principle of universality:** This concern was related to not offering the same programs across the entire service territory and the correct funding mechanism to use in this scenario. The other gas utilities noted the concern about the possibility for unequal treatment in different income classes, as the largest peak hour savings will accrue to larger homes and it may not be economic to provide the same benefits to lower income residences.

2.2 Differences between Electric and Natural Gas Utilities

Electric utilities have been using Demand Side Management and Demand Response (referred to in Ontario by electric utilities as Conservation & Demand Management or "CDM") programs to reduce the need for new generating capacity and transmission capacity for many years. However, the electric industry has relatively limited experience with DSM to defer distribution system infrastructure. Like natural gas DSM, most electric utility DSM programs are focused on reducing annual consumption. Where the electric utilities use DSM to offset infrastructure investment, the focus is generally on power generation capacity, or incremental transmission capacity into the company's service territory, rather than the impact on electricity distribution infrastructure. While interest in using DSM or DR to impact electricity distribution infrastructure has been increasing, so far, the information on the effectiveness of the programs has been limited.

Some concepts used for electric transmission and distribution ("T&D") facilities deferral in the IRP process can be applied to natural gas utilities. However, there are some important differences between electric and gas infrastructure planning processes that need to be accounted for when trying to draw parallels between the electric industry approach to IRP and gas utilities approach. These differences include:

- **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.[7] These differences in planning time of day tend to increase the value 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.
- **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.
- **System Outage Risk:** Electric systems are designed with an acceptable level of system outage risk, while gas systems are designed with a higher degree of reliability. The reliability standard required for the natural gas system is discussed in more detail in the review of the facilities planning process section. The higher degree of reliability required by the gas industry, with minimal risk tolerance for outages and increased costs to restart systems should outages occur, increases the costs associated with monitoring and evaluating the impacts of Geo-Targeted DSM programs targeted at reducing infrastructure investments, and increases the risks of non-performance associated with the DSM programs, and places utmost importance on ensuring savings can be realized and capacity requirements met without reinforcement.
- **Resource Planning**: Electric utilities must either acquire power and capacity from the market or produce their own. An electric utility IRP contains a review and assessment of the trade-offs between various generation and electricity purchase options. Gas utilities, in

[7] The peak demand period for facilities planning used in our analysis is the peak hour, which typically occurs during the morning period. For planning purposes, the peak period demand is projected based on extreme weather conditions, which typically occur on the coldest anticipated winter day, or design day. The duration of the peak period considered in the planning process depends on the type of infrastructure being evaluated. For individual service connections, the peak period used to size the service connection should be sufficient to meet the maximum customer demand. For certain distribution infrastructure projects serving a limited number of customers, the peak period used for facilities planning may need to be as short as 15 to 30 minutes, while larger transmission assets may be planned based on a longer time frame, potentially a 24-hour design day.

contrast, only acquire resources from the market. A natural gas IRP's purpose is to assess energy delivery infrastructure requirements needed to deliver gas to end-use customers.

- **Peak Hour Data Availability**: The need to measure peak hour 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 hour demand at the individual customer level is available for the electric industry, and subsequently allows for assurances through data that savings will be realized. Most gas utilities customer meters are read every other month.

The differences between the electric system and the natural gas system reduce the cost-effectiveness of DSM as an alternative to new infrastructure for natural gas utilities relative to electric utilities. The electric industry can achieve greater infrastructure cost savings from similar DSM and DR measures, due to the higher cost structure of the industry. The difference in risk tolerance between the industries, for capacity shortage, also increases the attractiveness of DSM and DR for to reduce infrastructure deferral and avoidance in the electric industry relative to the natural gas industry.

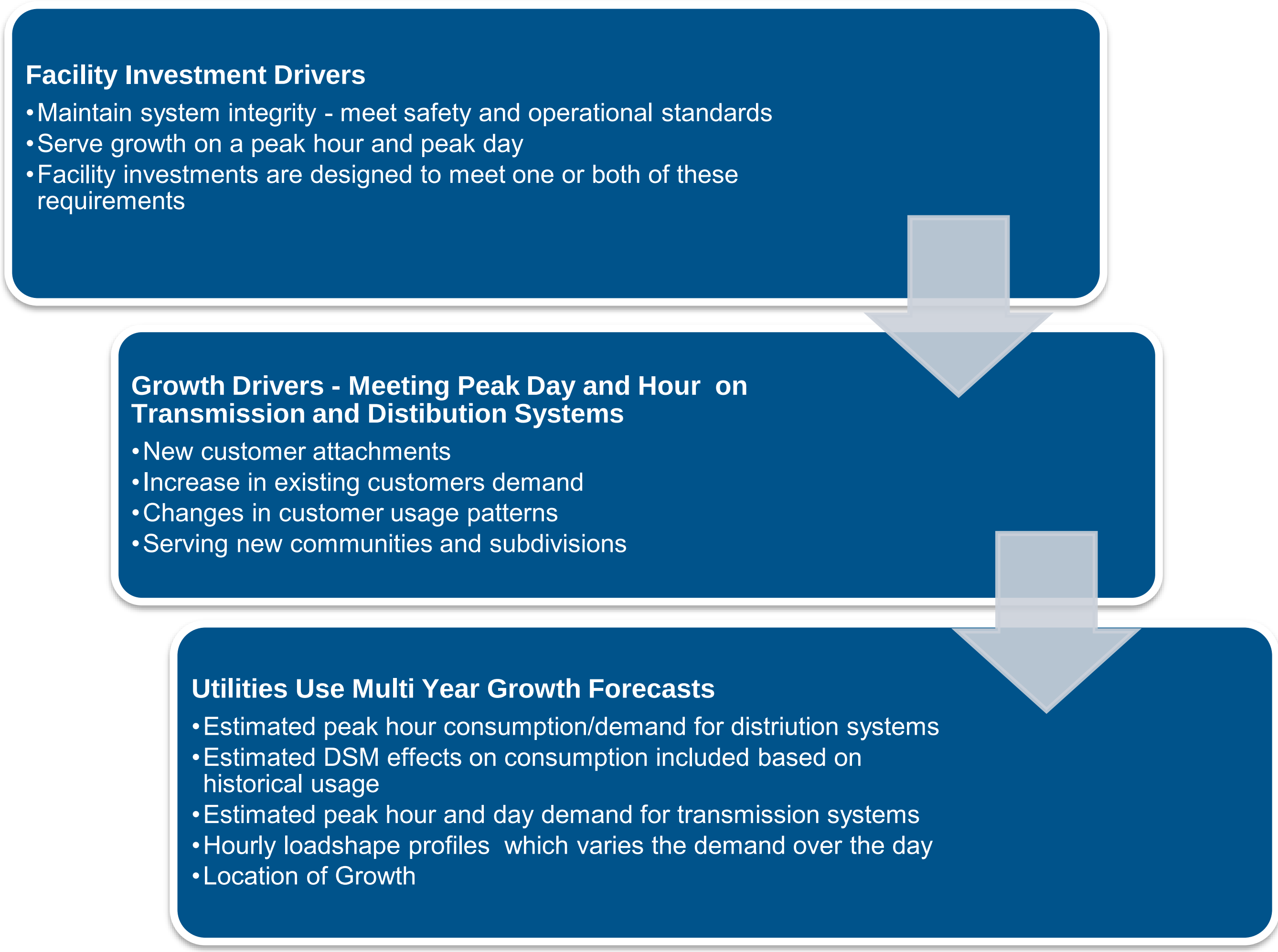
In addition, the use of DSM in the electric industry to reduce capacity requirements, and the ability to accurately measure peak demand has resulted in a better understanding of the impact of DSM on peak requirements in the electric industry than in the natural gas industry. This difference reduces the risk to the electric industry associated with the reliance on DSM to displace electricity infrastructure relative to the risk to the gas industry of relying on DSM to reduce the need for natural gas infrastructure. Until the gas industry invests in advanced metering technology, it will be challenging for the gas utilities to measure the impacts of DSM programs on baseline peak hour demand.

As a result, geo-targeted DSM programs are likely to be more cost-effective for the electric industry than they are for the natural gas industry.

3. Overview of Natural Gas Facility Facilities Planning

The following exhibit provides an overview of the natural gas facilities planning process. Key items are discussed in more detail in the following sections.

Exhibit ES 1: Overview of the Facilities Planning Process



3.1 Facilities Planning Principles

Facility investment plans are based on a long term growth forecast intended to identify potential incremental facility requirements and to develop these plans prior to the need for new facilities. ***The primary goal of facilities planning is to ensure that the utility infrastructure is of sufficient size and installed at the appropriate/required time to provide reliable natural gas service at the design condition*** consistent with reasonable costs.

Facility investments are required for a variety of reasons; although all investments are predicated on the need to reliably serve system demands at the required customer delivery pressure at the design degree day. Individual facility investments may be required to:

- Maintain system integrity, including the relocation and replacement of existing facilities that no longer meet current class location, safety and operational standards as determined by other engineering criteria.

- Serve growth in peak hourly and peak daily demand on existing systems resulting from attaching new customers, growth in existing customer requirements, and changes in customer usage patterns
- Serve new communities, new subdivisions and main extensions to unserved locations

Often, facility investment projects are designed to accomplish more than one of these requirements.

Currently, the Gas Utilities develop facility investment plans with multiple-year demand forecasts. The facilities planning process for distribution systems require the estimation of peak hour consumption for each year in the planning forecast. The facilities planning process for transmission facilities requires forecasting of both peak hour and peak daily demand, with an hourly load profile that varies the demand for gas over the day.

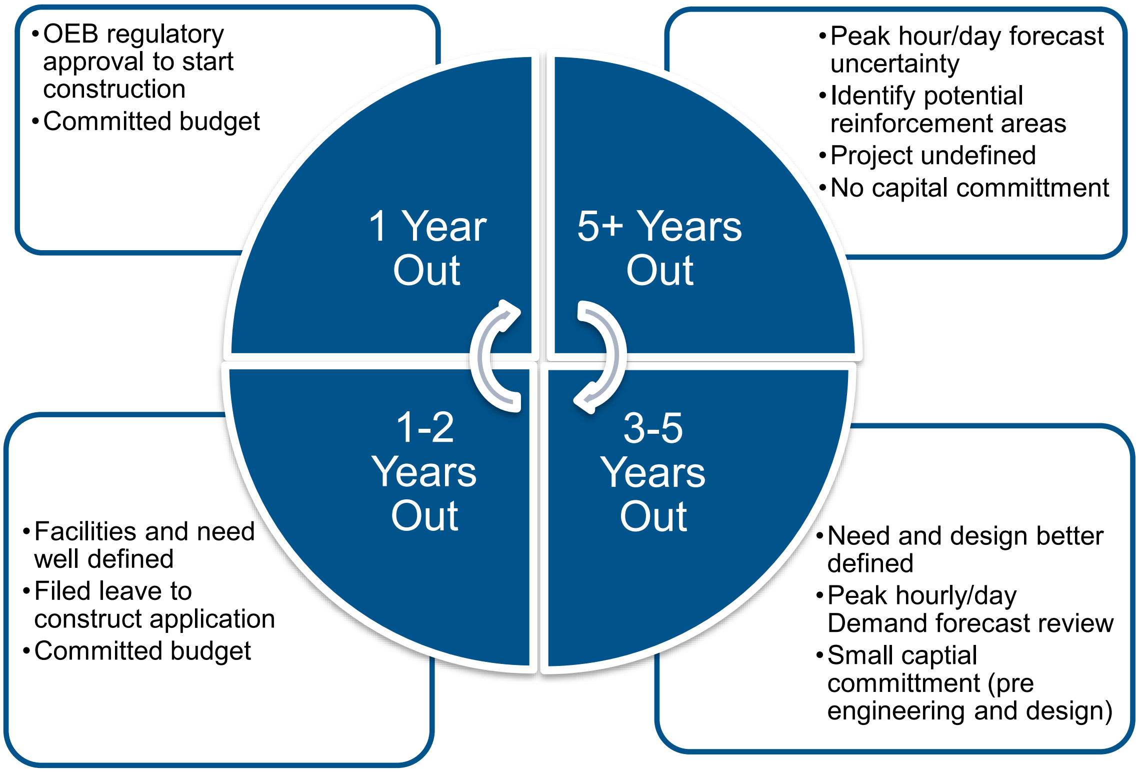
Historical gas use is used as a base to predict future consumption. The planning process includes changes in gas use resulting from historical implementation of DSM measures, as well as other factors such as improved building codes, and higher energy efficiency standards for natural gas equipment. However, the facility investment plans do not factor in DSM program effects on future peak day or peak hour demand.

The facilities planning process is designed to allow the Gas Utilities to proceed with planned investments, or accelerate/defer/revise planned investments depending on how closely customer attachment rates and demand growth match the forecast.

3.2 Facility Investment Plan Schedules

Facility investment plans consider a multi-year forecast of system growth, as well as known replacement and relocations. The plans are reviewed annually to reflect changes in outlook, and updated as needed, to reflect changes in the forecast and as growth becomes more certain. A typical facility investment plan begins by identifying the expected need for additional capacity about five years prior to the time that the capacity is likely to be required. No capital would be committed at this point. Between three and five years, the forecasts of demand growth are refined, projects with the potential to meet the requirement are identified, capital budgets are developed, and small initial investments are made for engineering, environmental assessments and design. During the period between one and three years prior to the identified need, the project is fully specified, the detailed capital budget is identified, and the gas utility submits for leave to construct. During this period, significant costs are incurred by the gas utility to finalize the engineering, begin land acquisition, go through the leave to construct process, and go through the required permitting and regulatory processes. The facility is built in the final year after the leave to construct is approved by the Board.

Exhibit ES 2: Facilities Planning Timeline



3.3 Consequences of Insufficient Facilities

Natural gas pipeline systems are designed to serve customer requirements during “design day” conditions. The planning design day is typically based on the coldest winter conditions deemed likely to occur. Under these cold weather conditions, the gas utility would likely curtail deliveries to interruptible customers consistent with the terms of the contracts signed by these customers.

In the event that the facilities in place are insufficient to be able to deliver the required demand on the design day, the gas utility will not be able to serve firm customer demand. The gas utility may not be able to react quickly enough to avoid unplanned customer outages. If there is time, the gas utility might call force majeure on large volume or power generator customers and / or may choose to shut down entire sections of the distribution system. The curtailment of firm large volume customers would create significant negative economic issues for the affected customers especially if critical equipment is damaged. Shutting power generators could cause broader issues, such as widespread electricity system outages.

If system operating pressure falls below minimum customer requirements, there may be widespread uncontrolled outages. These outages are difficult for the utilities to predict and manage. Firstly, these locations need to be identified and isolated by valves from the operating portion of the system. The utility has to physically shut off each customer’s gas meter, and then the affected system needs to be purged of air, if a loss of containment has occurred. Once this is completed, the utility must physically turn on each gas meter and then enter the customers building to inspect and relight each gas appliance at incremental cost. 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 large scale relight would be expected to take weeks rather than days or hours to resolve. Insufficient infrastructure would lead to a system shut down during the coldest part of the winter, leaving residential and commercial customers without heat during dangerously cold weather. Utilities likely would need to enact emergency plans and would need hundreds of personnel to relight customers. Community emergency plans may need to be activated to move people into warming centers and provide food.

3.4 Forecast of Peak Day and Peak Hour Demand

The facilities planning process for a pipeline system requires the estimation of peak hour and peak day consumption for each year in the planning forecast, as well as an hourly load shape (profile). There are three main customer types in this planning process:

1. **Firm Contract Customers**: Large volume Commercial and Industrial customers that have contracts obligating the utility to provide the customers required hourly and daily firm delivery service. The firm contract customers have hourly and daily gas measurements which increase the accuracy of the estimated customer peak usage.
2. **Interruptible Contract Customers**: Large volume Commercial and Industrial customers which have some or all of their gas requirements contracted as interruptible service. These customers' contracts can include a fixed number of days the utility can call interruptions and require the customer to shut down gas usage. These customers often have alternate fuel capability and switch fuel use from natural gas to the alternative fuel, (which may have a higher GHG or air quality impact), or can shut down processes when called to interrupt by the utility. These customers could be curtailed under design conditions and transmission facilities are not normally installed to maintain service to these customers on design day.

   The Gas Utilities do consider interruptible load in the facilities planning process as they have to ensure that the pipeline systems can accommodate those interruptible volumes during off peak times. Since there may be a fixed number of days where the utility can call interruptions, there may be cases where the pipeline systems need reinforcement to comply with the contracts for these customers.

3. **General Service Firm Customers**: These customers include residential and small commercial and industrial firm service customers. Existing general service customers are assumed to behave in a manner consistent with their recent 24 month weather adjusted consumption behavior. The monthly billing history of each customer is examined and statistical relationships are fit to determine monthly consumption as a function of monthly heating degree days. The utilities use this process to estimate the peak day demand for existing customers at the design degree day.

   Customer usage of gas varies throughout the day and the peak gas usage occurs in the morning hours between 7 and 9 am. The usage is highest during this period as most people start their day at similar times. The highest co-incidence of furnace, hot water and other gas use occurs in the morning.

The facilities planning process forecasts new customer attachments and changes in per customer requirements. New customers are modeled based on a typical average for new customers within each "customer class" (for example a large single-family detached house). The count of new customers is based on historical connection rates plus what is known about specific new large buildings and housing developments.

While the use per customer data that is utilized to project consumption per existing and new customer takes into account recent historical trends, including the impacts from historical energy efficiency efforts, the planning process does not explicitly factor in the impact of future DSM programs on peak day or peak hour consumption.

3.5 Sizing of Incremental Facility Investments

One of the challenges with developing new facility investment projects is determining the future demand and the location of the demand. Economic development, location of new housing developments, and customer types are all difficult to forecast with certainty, creating a range in future demand growth that must be planned for.

There are significant economies of scale associated with the construction of facility investment projects. The cost of the incremental unit of capacity declines as the size of the project increases due to efficiencies in planning, right-of-way and easement availability, mobilization costs, and labor and materials costs.

If the project proves to be undersized relative to future system growth, additional facility investment projects are likely to be much more expensive than increasing the size of the initial project. As a result, the utility, and the utility's customers have a significant economic incentive to plan based on upside uncertainty in the forecast rather than downside uncertainty.

New infrastructure projects can also result in significant disruptions to streets and communities that the projects pass through, leading to a strong incentive to be "one and done" with any project or group of projects. As a result, the timing of facility investments can be influenced by factors outside the control of the Gas Utilities. In order to be "one and done" investments can be accelerated or delayed to correspond with municipal development schedules related to infrastructure projects such as bridge repair and replacement, road construction or water and sewer repairs and extensions.

The desire to take advantage of other infrastructure projects and the need to minimize community disruptions can lead to upsizing or accelerating facility investments for projects where future expansions would be particularly disruptive or expensive, and may make deferral of some gas infrastructure projects impractical despite the potential for geo-targeted DSM to reduce demand.

3.6 Impact of Reductions in Forecast Demand Growth

Reductions in forecast demand growth can impact facility investment plans in several ways. Generally, a reduction in peak hour load will result in decreased facility investment plans. The change in infrastructure requirements can result in:

- Delay or cancellation of project implementation.
- Decreased diameter of the pipeline.
- Decreased length of pipeline looping to be installed.

For many projects, the amount of capacity added is determined in part by the length of the pipeline project. Growth in a specific location can often be served by a project that eliminates constraints between a supply point and the region with expected demand growth. This rarely requires the construction of an additional pipeline from the supply point all the way to the location of the demand growth. Instead, the incremental capacity can be provided by adding sections of pipe on the most constrained section of the system. Hence, reducing hourly demand growth could also reduce the need for specific sections of new pipe.

4. Differences between Facilities and DSM Planning Criteria and Approach

While DSM programs do broadly impact facilities requirements, and the cost savings associated with a broad-based reduction in distribution costs are generally included in the DSM planning process, the linkages between DSM planning and facilities planning are currently passive rather than active, and are not sufficient to actively integrate geo-targeted DSM programs into the facilities planning process. There are a number of differences between the DSM and facilities planning process that must be reconciled in order to potentially use geo-targeted DSM to reduce infrastructure investments. The most important are summarized below.

4.1 Differences in Risk and Reliability Criteria

Perhaps the most challenging difference to address between the current DSM and facilities planning processes is the difference in risk and reliability criteria.

- The primary goal of the facilities planning process is to ensure the utility distribution system is sized sufficient to ensure that demand will not exceed the system capacity at design conditions. As a result, the facilities planning process is based on a primary philosophy of risk avoidance.
- The primary goals of the DSM program planning process are to reduce annual natural gas consumption and to influence a culture of conservation. DSM success has several metrics but often is evaluated based on program participation rates rather than measurement of actual savings. Risk is inherent in DSM planning and implementation, in part to encourage innovation in program delivery and increase program uptake.

The use of geo-targeted DSM programs to reduce the need for infrastructure projects changes the balance of risk for the DSM program. For a DSM program to be relied upon as an alternative to a new infrastructure investment, it would need to satisfy the same risk criteria as the infrastructure investment that it is replacing. As highlighted earlier, the facilities planning process risks are not just financial; there are also potential gas system outages if there are insufficient facilities. This is a risk that is not present for standard DSM programs, where the associated risks are strictly financial. As a result, if a geo-targeted DSM program designed to reduce infrastructure investment is non-performing and fails to deliver the expected savings, or if the savings appear to be uncertain during the evaluation phase, the utility will be required to proceed with the infrastructure project in order to ensure the same level of overall system reliability. This would lead to an increase in the overall cost of serving the load growth, as both the DSM costs and the infrastructure costs would need to be recovered. In addition, the infrastructure project may need to be accelerated in order to meet the need, resulting in higher than anticipated or originally budgeted project costs.

4.2 Coordinating Timelines for Geo-Targeted DSM Programs

On an operational basis, the DSM planning process operates on a relatively short time-frame. The program planning schedule depends on the type of program, assuming that the program is being implemented in the current DSM Framework, and that the policy issues as described in Section 7 are settled and an appropriate framework is developed. The range of timing from decision on whether or not a program should be implemented to actual implementation ranges from 3 to 12 months. Hence, excluding any regulatory approval delays, the Gas Utilities could be able to implement a new geo-targeted DSM program within 12-18 months of the decision to proceed. This is recognizing that the Gas Utilities have had no experience with geo-targeted program design and these timeframes are based on broad-based DSM efforts. The timing may change, as more is known about geo-targeted program design; the Gas Utilities expect to gain insight on these program enhancements during the course of the pilot studies.

The length of time that the DSM program will need to be in place in order to reduce peak demand by enough to reduce a specific infrastructure project will always depend on the specific customer characteristics, the DSM program and the specific infrastructure project. The current lack of information on the ability of natural gas DSM programs to impact peak demand makes it currently impossible to know with certainty when a DSM program needs to be implemented and how long the program needs to be in operation to successfully reduce the infrastructure project. However, the Gas Utilities anticipate that most geo-targeted projects will require two to four years of fully effective implementation to reduce demand growth sufficient to allow the facility investment to be reduced.

For a geo-targeted DSM program to reduce an infrastructure project, the results of the geo-targeted program would need to be in place with sufficient reliability to ensure that the new facility will not be required to meet demand. Generally, this would require a successful evaluation of DSM program results prior to the time of the leave to construct filing. Given the need to evaluate the impacts of the DSM program, the DSM program would need to be completed or demonstrating measurable results, at least 2 years prior to the date at which the additional capacity provided by the infrastructure project was initially projected to be required.

Hence, a successful geo-targeted DSM program would need to be approved and put into motion about 3 to 5 years prior to the expected in-service date of the targeted facility investment. However, the need for new facilities is generally uncertain at four to five years prior to the in-service date. As a result, geo-targeted DSM programs may need to be implemented before the Gas Utilities have a high degree of certainty that the facility investment will actually be required, potentially leading to an expenditure that may not produce the full value as intended.

4.3 DSM Program Impact Uncertainty

As discussed in Sections 5 and 6 of this Executive Summary, ICF expects most DSM measures to reduce peak day demand. However, the ability of a given DSM program to achieve a specific level of peak period demand reduction is relatively unknown. As a result, in order to ensure with sufficient reliability for planning purposes that the impact of the DSM program on peak period demand is sufficient to defer a facilities project, the DSM program will need to be designed to achieve greater peak period savings than the facility project that it replaces.

For example, a portfolio of DSM programs might have peak period impacts with a standard deviation of 10% around the expected impact. In order to plan on DSM program meeting the required peak period load reduction 95% of the time, the DSM program would need to be sized to meet 116% of the required capacity. The same program would need to be sized at 121% of the required capacity to meet requirements 98% of the time.

The magnitude of the required oversizing of the DSM program can be influenced by the timing of the DSM program implementation. Earlier implementation of the DSM program would allow for additional monitoring and evaluation, and provide additional assurances that the facility could be constructed before the capacity is required if the DSM program appears unlikely to achieve its objectives. In practice, the optimum planning process is likely to include both oversizing of the DSM programs, and maintenance of the ability to construct the facility if needed, in order to assure required system reliability.

5. DSM Impacts on Peak Day and Peak Hour Demand

ICF leveraged the results of the OEB CPS, building modeling, and hourly gate station data from the Gas Utilities to develop load profiles and hours-use factors to estimate the winter peak demand breakdown and the achievable winter hourly peak demand for the Gas Utilities for the DSM measures included in the OEB CPS. This included DSM measures that apply to various types of residential, commercial, and industrial sector facilities and equipment. The comprehensive list of energy efficiency measures for the OEB CPS included 52 residential measures, 59 commercial measures, and 57 industrial measures. The scope of the DSM measures included higher efficiency equipment, such as condensing boilers and tankless water heaters, envelope measures, such as air leakage sealing and attic insulation, and controls measures, such as adaptive (smart) thermostats and demand control ventilation.

5.1 DSM Impacts on Peak Day and Peak Hour by Sector

Although ICF's analysis focused primarily on the peak hour, which was found to occur from 7-8 am in all regions, peak demand impacts across five peak periods were considered. This included each hour of the morning lift period between 6 am and 10 am (including the peak hour) and the entire peak day, considered as an aggregate.

The broad-based DSM impacts on peak day and peak hour demand by sector (residential, commercial, industrial) are summarized below. For each sector, the analysis identified which sub-sectors and end-uses have a larger relative impact on the achievable peak demand savings.

5.1.1 Residential Sector Results

The residential sector included all homes except for multi-unit residential buildings (MURBs or apartment buildings). ICF's analysis indicated that the highest peak demand savings potential in the residential sector occurs during 9-10 am and that adaptive thermostats could lead to an increase in peak demand during the peak hour (7-8 am). Other high-level results for the residential sector analysis can be summarized as follows:

- Low income homes represent a disproportionately large share of peak hour savings relative to peak hour demand due to the age and the nature of the housing stock
- Space heating measures are quite important from a peak demand perspective since they have both a higher relative impact and a higher savings potential
- The top three residential peak demand measures are all related to air tightening the building envelope

5.1.2 Commercial Sector Results

ICF's analysis indicated that the highest peak demand savings potential in the commercial sector occurs during 6-7 am, although the savings potential during this period is only slightly higher than the peak hour (7-8 am). Other high-level results for the commercial sector analysis can be summarized as follows:

- Sub-sectors that are more important from peak hour savings perspective include Offices, Education, Retail, Other.
- Low income apartments have a relative large peak hour savings potential relative to Reference Case due to the age and the nature of the housing stock.
- Space heating is the most important end-use but there is also significant potential in DHW.
- Space heating measures, such as high efficiency boilers, condensing boilers, and condensing makeup air units (MAUs), are important from a peak hour savings perspective.

5.1.3 Industrial Sector Results

ICF's analysis indicated that the highest peak demand savings potential in the industrial sector occurs during 6-7 am, although the savings potential during this period is only slightly higher than the peak hour (7-8 am). Other high-level results for the industrial sector analysis can be summarized as follows:

- Manufacturing facilities and greenhouses/agriculture are more important as compared to other industrial customers from a peak hour savings perspective.
- Demand savings from mineral processing industries are less concentrated during the peak hour, but are still important due to the high percent savings that can be attained.
- The HVAC and Other end-use is quite important from a peak demand savings perspective since the demand and savings potential is focused on the winter peak hour.
- Space heating measures are important to consider in the industrial sector as well if the goal is to reduce winter peak demand.

5.1.4 All Sectors

The aggregated results for all sectors indicated that the highest peak demand savings potential occurs during 9-10 am, although the savings potential during this period is only slightly higher than the peak hour (7-8 am).

- ICF's analysis suggests that DSM is not expected to shift the timing of hourly peak demand.
- Compared to the Industrial sector, the achievable savings for the Commercial and Residential sectors are slightly more concentrated during the peak demand hour.
- The Industrial sector can achieve a much higher percent savings compared to the Commercial and Residential sectors.

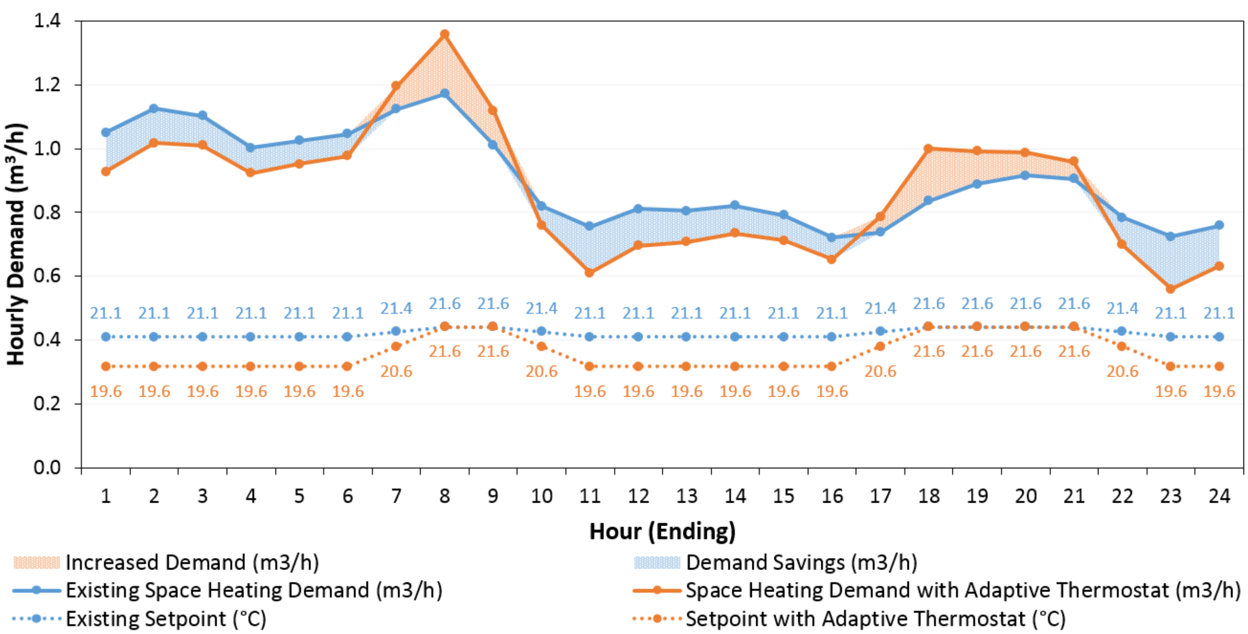
5.2 DSM Measures of Interest

The majority of energy efficiency measures were found to reduce both annual load and peak hour load. However, there were a few measures that had the potential to increase the peak hour load on a distribution system, even though they did contribute to a decrease in annual consumption. Adaptive thermostats and tankless water heaters were investigated in detail due to their significant annual savings potential and the complexity associated with their potential impacts on peak demand. The results of the analysis on these measures and the broader DSM impacts on peak day and peak hour demand are summarized below.

5.2.1 Adaptive Thermostats

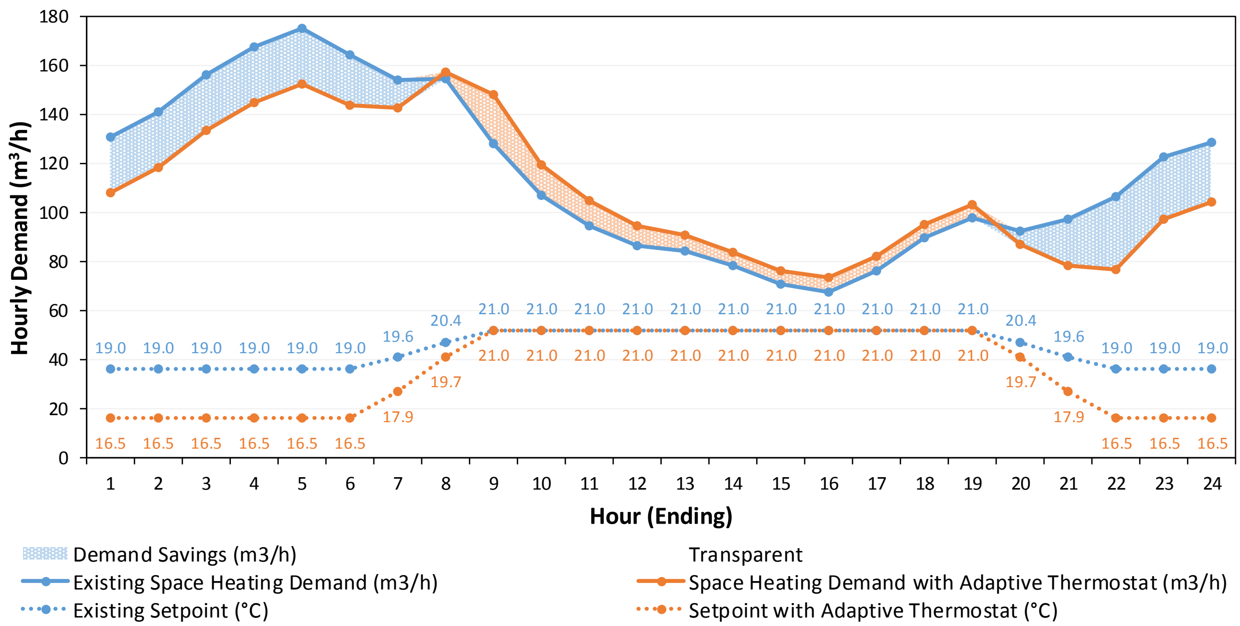
Adaptive thermostats account for a significant amount of the achievable DSM potential in both the residential and commercial sectors. According to the OEB CPS, in Ontario, adaptive thermostats account for 21.5% of the Business As Usual (BAU) Achievable DSM savings (44.8% of residential, and 2.62% of commercial). Although this measure leads to annual gas savings, building modeling suggests that adaptive thermostats contribute to increased demand during winter peak hour periods. These periods of increased demand occur when heating systems are recovering from temperature setback. Exhibit ES 3 demonstrates the demand impacts resulting from the implementation of adaptive thermostats in the residential sector during design day conditions. As shown in the exhibit, residential building modeling indicates that adaptive thermostats lead to a significant increase in winter peak hour demand in the residential sector.

Exhibit ES 3: Residential Sector Hourly Demand Comparison for Adaptive Thermostats



Commercial building modeling also suggested that adaptive thermostats lead to increases in winter peak hour demand in the commercial sector but, as demonstrated in Exhibit ES 4, the impact is much smaller than the residential sector. This is due to the lower applicability of this measure in the commercial sector and the diversity of operating schedules in the different types of commercial facilities being considered.

Exhibit ES 4: Hourly Demand Comparison for Adaptive Thermostats Applied to Offices



In both the residential and commercial modeling results, it can be seen that adaptive thermostats lead to increased demand during other non-setback hours during the winter peak day since it can take several hours to heat up a building's entire thermal mass. The results of this analysis suggest that, where adaptive thermostats are deployed on a broad basis, their impacts on a natural gas distribution system would need to be closely monitored. In the residential sector in particular, adaptive thermostats appear likely to lead to increases in distribution capacity requirements.

It is important to note that adaptive thermostats can be integrated into demand response (DR) programs to help mitigate peak demand increases during peak hours. Based on recent consultations completed by ICF,[8] thermostat manufacturers including Nest, ecobee, and Honeywell indicated that they have ran a large number of DR programs. Although these programs are typically focused on summer peak reduction, the thermostat manufacturers indicated that DR programs focused on winter peak reduction are feasible.

5.2.2 Tankless Water Heaters

Typically, tankless water heaters have a much higher maximum natural gas consumption rate than standard water heaters. The potential increase in peak natural gas consumption by these appliances raised initial concerns that even though tankless water heaters would reduce annual and peak day natural gas consumption, they might increase peak period consumption. Only limited measured data is available on the impact of tankless water heaters on peak period natural gas demand. As a result, ICF used building modeling techniques, combined with the available data to estimate the impacts.

[8] ICF, Compatibility Study: Smart Learning Thermostats, completed on behalf of FortisBC, April 10, 2017.

ICF modeling using metered DHW consumption profiles at 5 minute intervals suggests that tankless water heaters can increase peak demand during the relatively short periods that they are in use. However, on an aggregate basis for a community, ICF's analysis suggests that tankless water heaters contribute to hourly winter peak demand savings; especially if the diversity of hot water consumption is considered.

Exhibit ES 5 and Exhibit ES 6 summarize the results of ICF's modeling, which compared the demand draw of tankless water heaters and storage water heaters for a community of homes with heavy hot water usage. As depicted in Exhibit ES 5, there are brief instances where the aggregate demand for the community increases if demand is considered on 5-minute increments. However, Exhibit ES 6 demonstrates that, if demand is averaged out over 60-minute increments, tankless water heaters are consistently resulting in demand savings for the community. ICF's modeling was based on 5-minute interval hot water consumption data for homes with high hot water consumption and different types of hot water usage patterns.

Exhibit ES 5: Comparison of Water Heater Demand for Community with Heavy Hot Water Use, 5-Minute Intervals

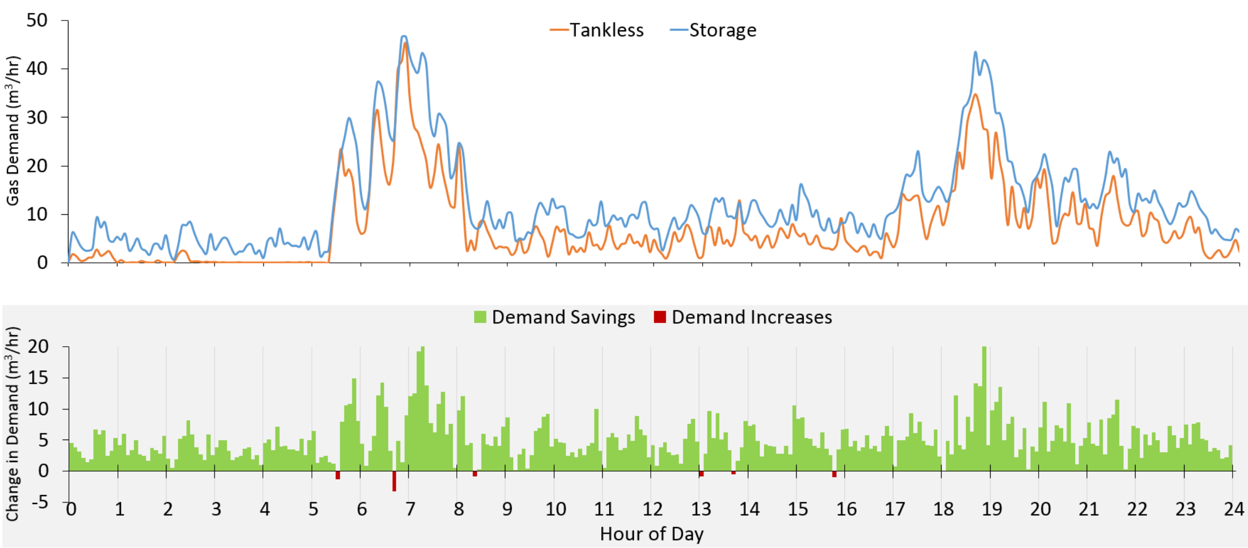
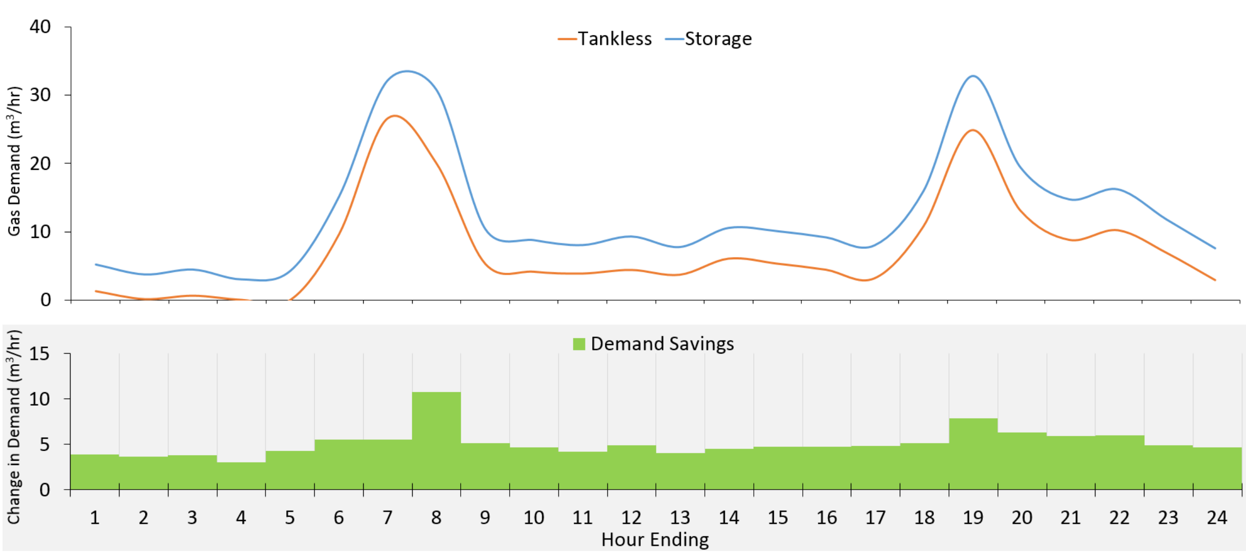


Exhibit ES 6: Comparison of Water Heater Demand for Community with Heavy Hot Water Use, 60-Minute Intervals



6. Potential Impacts of DSM on Facilities Requirements

ICF leveraged the results of the DSM impacts analysis described in Section 5 to evaluate the potential of DSM programs to impact peak period demand and to reduce infrastructure investments.

As part of this step in the process, ICF worked with utility staff to identify appropriate hypothetical case studies based on specific examples of utility infrastructure investments. Information from these case studies that fed into the analysis included project costs, current and forecasted capacity requirements, and the distribution of energy consumption by facility type. The DSM supply curves were used to compare the costs of peak demand reduction through the implementation of DSM against infrastructure project costs.

6.1 Peak Hour DSM Supply Curves

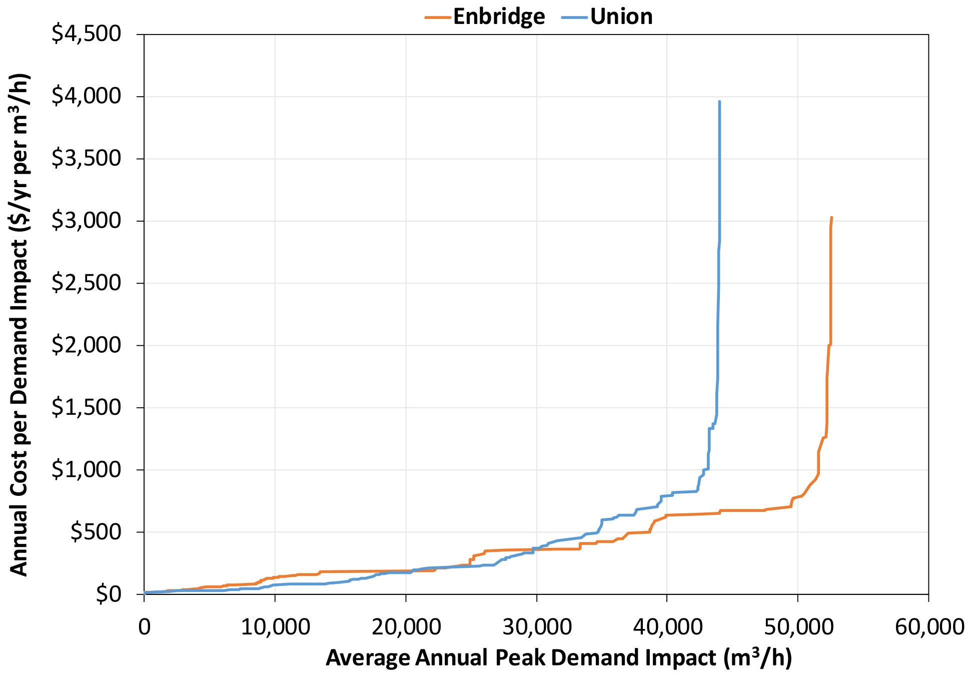
The peak hour DSM supply curve for each utility shows the relative DSM program cost (i.e. $ per m^3/h) to achieve the estimated peak hour demand impacts in each utility service territory. The DSM supply curves prioritize the measures based on their cost-effectiveness, based on the cost per unit gas demand savings, with the most cost-effective measures being implemented first. Each of the DSM supply curves includes measures from all of the sectors being considered (i.e. residential, commercial, and industrial). For the residential and commercial sector, each measure is split into two parts, with the Business As Usual (BAU) scenario reflecting the impacts that can be achieved based on modest incentives and the aggressive scenario demonstrating the incremental demand impacts and costs based on high incentive levels. Costs and savings were aggregated for each of the industrial sector measures since these measures were generally found to be much more cost-effective and there was limited value in splitting out the BAU and aggressive scenarios.

The program costs used to develop these DSM supply curves are composed of both incentive and non-incentive costs. Incentive costs are based upon the estimated level of incentive required to influence measure adoption, while non-incentive costs are administrative costs for program delivery activities, including items such as marketing and labour for program staff.

The most cost-effective measures on the DSM supply curves include industrial measures to optimize and have increased control of existing systems (as further outlined in Section 6.3.1 below) which suggests that these measures should be implemented first if the goal is to reduce winter peak hour demand. Conversely, residential and commercial measures make up most of the least cost-effective measures (as outlined further in Section 6.3.1) and would be a lower priority under a winter peak hour demand program.

The potential peak hour demand impact potential of 44,035 m^3/h per year in Union Gas territory (as shown in the exhibit below) represents an annual average savings of approximately 1.24% over the total hourly reference case demand of approximately 3.54 million m^3/h. For the Enbridge Gas service territory, the potential peak hour demand impact of 52,546 m^3/h per year represents an average annual savings of approximately 1.05% over the total hourly reference case demand of approximately 5.01 million m^3/h. The differences between the Enbridge Gas and Union Gas service territories is largely driven by differences in customer mix. Union Gas, with a higher percentage of industrial demand has somewhat more DSM potential.

Exhibit ES 7: Broad-Based DSM Supply Curve for Enbridge & Union Gas



The application to specific projects will depend on the customer mix in the specific service territory served by the investment project. In the case studies reviewed below, the potential peak hour demand impact ranged from about 0.8% per year to 1.35% per year.

6.2 Application of DSM Supply Curves to Facility Investments

The peak hour DSM supply curves that ICF constructed leveraged measure-specific estimates of peak demand impacts and program costs. The numbers employed in these DSM supply curves are based on broad regional averages, including the distribution of different types of facilities, and the best available data on the penetration of different types of energy efficiency measures across each utility's service territory.

These DSM supply curves were used to estimate the peak demand impacts resulting from the implementation of DSM at the level of an individual facility investment, despite the obvious limitations with this approach, including a significantly larger degree of uncertainty with the results. One item that warranted special attention was the program costs associated with implementing DSM at the geo-targeted (i.e. community) level. Simply scaling the program costs from the broad-based analysis to estimate the geo-targeted program costs ignores the fact that there are efficiencies of scale associated with implementing DSM programs across a large service territory and these will not translate to geo-targeted programs. Essentially, although incentive costs can be scaled despite the size of the program, admin costs would be much higher for geo-targeted programs.

Geo-targeted DSM programs would tend to be smaller than most broad-based DSM programs and even for an equivalent program size (i.e. $/yr.), geo-targeted programs will be more expensive per unit impact than broad-based DSM programs due to several factors, including the need for metering and on-going monitoring of impacts. Based on the review of a 2014 ACEEE study,[9] which included an assessment of the annualized costs of implementing natural gas DSM program in a large number of US jurisdictions and provided a sense for how much these costs vary, and ICF's experience with implementing DSM programs across North America, ICF estimated that the cost of implementing geo-targeted DSM programs would be in the range of 1.5 to 2 times more expensive than implementing broad-based DSM programs, on a per unit savings basis. As such, the cost of implementing geo-targeted DSM programs is presented as a band.

The Gas Utilities staff also provided details pertaining to example facility investment projects, including associated costs, existing and projected system peak demand, and the best available data regarding the breakdown of peak demand by different types of facilities. These example facility investment projects were used as case studies to assess the theoretical potential costs and benefits of using DSM to reduce infrastructure investment. The broad peak hour DSM supply curves were scaled to match the demand of these case study facility investment projects, including the distribution by facility type. The resulting DSM supply curves were used to compare the estimated cost of peak demand reduction from DSM measures against the cost of facility investments for these example case studies.

6.3 Accounting for Other Costs and Benefits from DSM Programs

6.3.1 Reduction in Annual Natural Gas Demand

The primary design objective of DSM programs designed to reduce infrastructure investment would be to reduce peak period demand. However, DSM programs implemented with the goal of impacting peak will also save avoided costs associated with annual energy efficiency including gas commodity cost savings, upstream capacity costs and the value of non-energy benefits including the value of the carbon emission reductions. ICF's analysis does not account for any additional benefits. How various savings would be valued in an IRP context will require additional analysis.

6.3.2 Duplication of DSM Benefits

The DSM supply curves incorporate all of the DSM measures included in the OEB CPS that are capable of reducing peak period demand. Many of these measures will be available to the Gas Utilities' customers through existing broad-based DSM programs. ICF did not attempt to separate out the impact of broad-based DSM programs when developing the initial DSM supply curves for geo-targeted programs in this initial study. Since the natural gas demand forecasts used to develop infrastructure investment plans are based on demand data that includes the impact of existing DSM programs, the current DSM supply curves likely overstate the potential incremental reduction in peak period demand available for geo-targeted DSM programs.

Determining the best approach to eliminating the duplication of DSM benefits is expected to require additional analysis, and may require an assessment on a case by case basis.

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[9] Molina, Maggie, ACEEE, The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs, Report #U1402, March 2014.

6.4 Intersections between DSM and Infrastructure Planning

The Gas Utilities identified three areas where the intersection between DSM programs and the infrastructure planning process could impact (reduce) infrastructure costs.

1. **Broad-Based DSM Impacts on Infrastructure Planning Reinforcement Projects (Passive Deferral)**

All DSM programs have the potential to impact peak hourly and peak daily demand and to change the need for new infrastructure investment regardless of whether or not the programs are specifically designed to reduce peak hourly or daily demand.[10] This is referred to as passive deferral of infrastructure investment.

The impact of historical broad-based DSM programs on infrastructure investment is inherently captured in the facilities planning process. Customer usage is updated each year using consumption based on recent historical usage. The historical usage used in the process reflects the impact of past and current broad-based DSM once it has materialized, but it does not reflect anticipated or unknown future DSM program impacts.

Passive deferral of infrastructure investment based on broad-based DSM activity requires two basic components to be accurately captured in the facilities planning process.

- Use of appropriate avoided infrastructure investment cost estimates that fully value the potential costs and benefits associated with deferral of facility investments by utilizing DSM programs.
- Accurate consideration of the expected impacts of Energy Efficiency measures and DSM programs on the peak hour and peak day demand forecasts used to evaluate the need for infrastructure investments.

2. **Geo-Targeted DSM Impacts on Facilities Planning for New Subdivisions or Community Projects**

The final type of infrastructure investments that might be affected by DSM are expansions to serve new communities or subdivisions. Serving new communities typically requires a significant investment in new pipeline capacity to deliver gas to the community, as well as reinforcements on existing parts of the system to meet the growth in overall requirements.

Given the nature of a new community expansion, where the project is necessary to provide the initial gas service to the community, DSM programs would not be useful in *deferring* the facility investment. However, in certain circumstances, the overall magnitude of the investment and project might be reduced if the DSM programs alone or in conjunction with other Distributed Energy Resources are capable of reducing the expected demand in the new community.

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[10] Not all DSM measures will impact peak hour or peak day demand in the same way. Most DSM measures are expected to reduce peak hour and peak day demand, although the relative magnitude of the impact will differ by some measure. Adaptive thermostats are expected to reduce peak day demand but increase peak hour demand. Other DSM measures may have no impact on peak hour or peak day demand.

3. Geo-Targeted DSM Impacts on Infrastructure Planning Reinforcement Projects (Active Deferral)

DSM programs that target peak hour and peak day demand reductions in specific areas where infrastructure investments are planned have the potential to delay, or avoid the need for the infrastructure investment. Use of Geo-Targeted DSM programs to reduce specific infrastructure projects requires three key steps:

- Identifying infrastructure projects that could be reduced by a reduction in peak hour or peak day demand.[11]
- Designing and implementing cost-effective DSM programs capable of reducing peak hour or peak day demand sufficient enough to reduce the infrastructure project within the available time frame.
- Verifying the effectiveness of the DSM programs on a timeline sufficient to ensure that infrastructure project can be reduced without impacting the Gas Utilities' ability to reliably serve natural gas system demand.

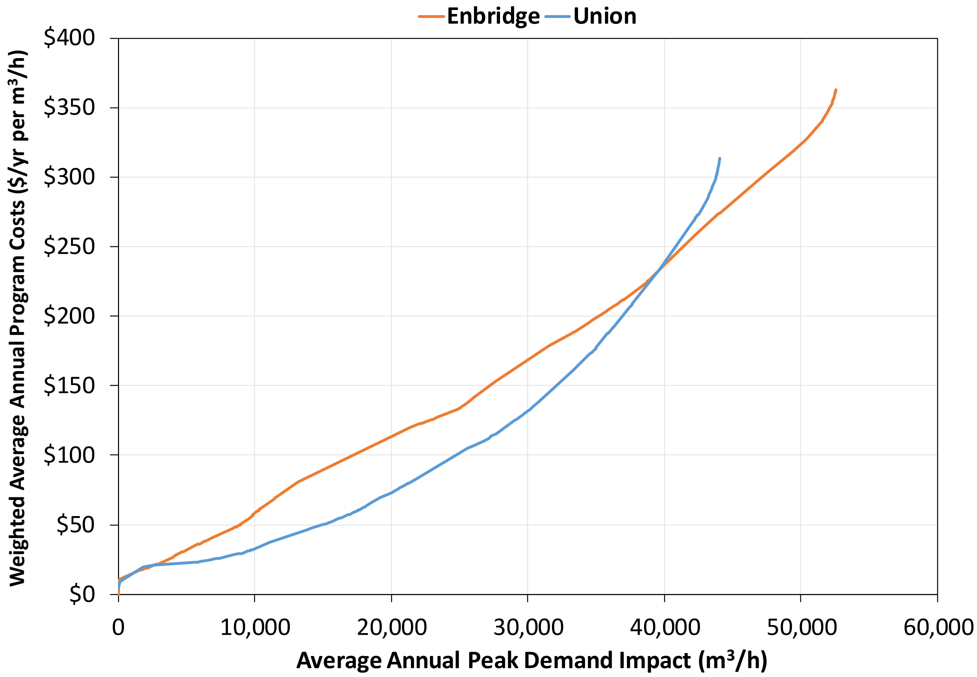
6.4.1 Broad-Based DSM

The peak hour DSM supply curve for each utility is presented below showing measures from all the sectors being considered (i.e. residential, commercial, and industrial). The broad-based analysis curves show the cost of implementing DSM measures against their demand savings impacts. Section 6.1 presented the broad-based DSM supply curve showing annual program costs on the vertical axis and the average annual peak demand impact (m^3/h) on the horizontal axis. Exhibit ES 8 presents the annual weighted average cost per unit demand impact, essentially demonstrating the weighted average program cost and savings that would be associated with implementing a program starting with the most cost-effective measure.

The majority of the industrial measures are at the bottom of the DSM supply curves presented in Exhibit ES 8, with some commercial and residential behavioral, optimization and control type measures also on the lower end of the supply curve for both Gas Utilities. Examples of some of the most cost-effective measures include industrial measures such as reduce boiler steam pressure, burn digester gas in boilers, regenerative thermal oxidizers, and ventilation optimization (ranging from an estimated annual $4-23 per m^3/h). Commercial measures including ventilation fan VFDs and ozone laundry treatment are also very cost-effective (estimated annual costs of $9-11 per m^3/h and $18-26 per m^3/h, respectively).

[11] Many infrastructure investments are driven by pipeline integrity requirements, class location and/or municipal replacement requirements, and would not have the flexibility to be delayed or avoided.

Exhibit ES 8: Broad-Based DSM Supply Curve for Enbridge & Union Gas – Weighted Average Annual Program Costs[12]



Measures that were found to be the least cost-effective are mostly commercial and residential sector measures. This includes commercial measures such as wall insulation, ENERGY STAR clothes washers, and advanced BAS/controllers, each with estimated annual costs greater than $300 per m^3/h.

6.4.2 Community Reinforcement

The Gas Utilities staff provided details based on a criteria provided by ICF pertaining to case study facility investment projects. ICF scaled the broad-based DSM supply curves to create the community-level supply curves. These scaled-down curves allowed for a comparison of the estimated cost of peak demand reduction from DSM measures against the cost of facility investments.[13] Furthermore, the following approach was taken to compare the facility investment projects to DSM:

- The full annual investments (program costs, including both incentives and admin) for DSM were modeled on an extended timeframe.

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[12] In Exhibit ES 8, the broad-based DSM program costs have been annualized over the lifetime of the DSM measures. As such, the annual DSM program costs cannot be calculated by multiplying the Weighted Average Annual Program Costs by the Average Annual Peak Demand Impact. In this particular example, the cost of implementing DSM to defer 40,000 m^3/h of growth in Union's service territory is estimated at approximately $98,975,000, and the peak demand impact of individual measures would persist from 1 to 30 years (the weighted average lifetime of the measures is approximately 15.2 years).
[13] As noted earlier, program costs were scaled up by a factor of 1.5 to 2 to account for the fact that admin costs related to running a geo-targeted program would be significantly higher than the admin costs associated with a broad-based DSM program portfolio.

- It was assumed that DSM would start being implemented 3 years ahead of a facility investment project.
- The net present value of the DSM program costs were compared against the net present value of the infrastructure investment costs.

Exhibit ES 9 presents the geo-targeted DSM supply curve for a community reinforcement project located in Enbridge's Central region. Based on information provided by the utility, the total capital cost of this project is approximately $8,200,000 and it involves the installation of 3.2 km of NPS 12" ST HP pipeline. As shown in Exhibit ES 9, ICF's analysis for this particular scenario suggests that the present value of the costs associated with running a geo-targeted DSM program is slightly lower than the present value of the costs associated with the reinforcement project. In other words, it may be more cost-effective to launch geo-targeted DSM program than to install the reinforcement project. This finding is primarily a result of the high capital costs of the reinforcement project and the relatively small demand growth rate in this community (i.e. 0.5% annually).

Exhibit ES 9: Supply Curve for Reinforcement Project in Enbridge's Central Region

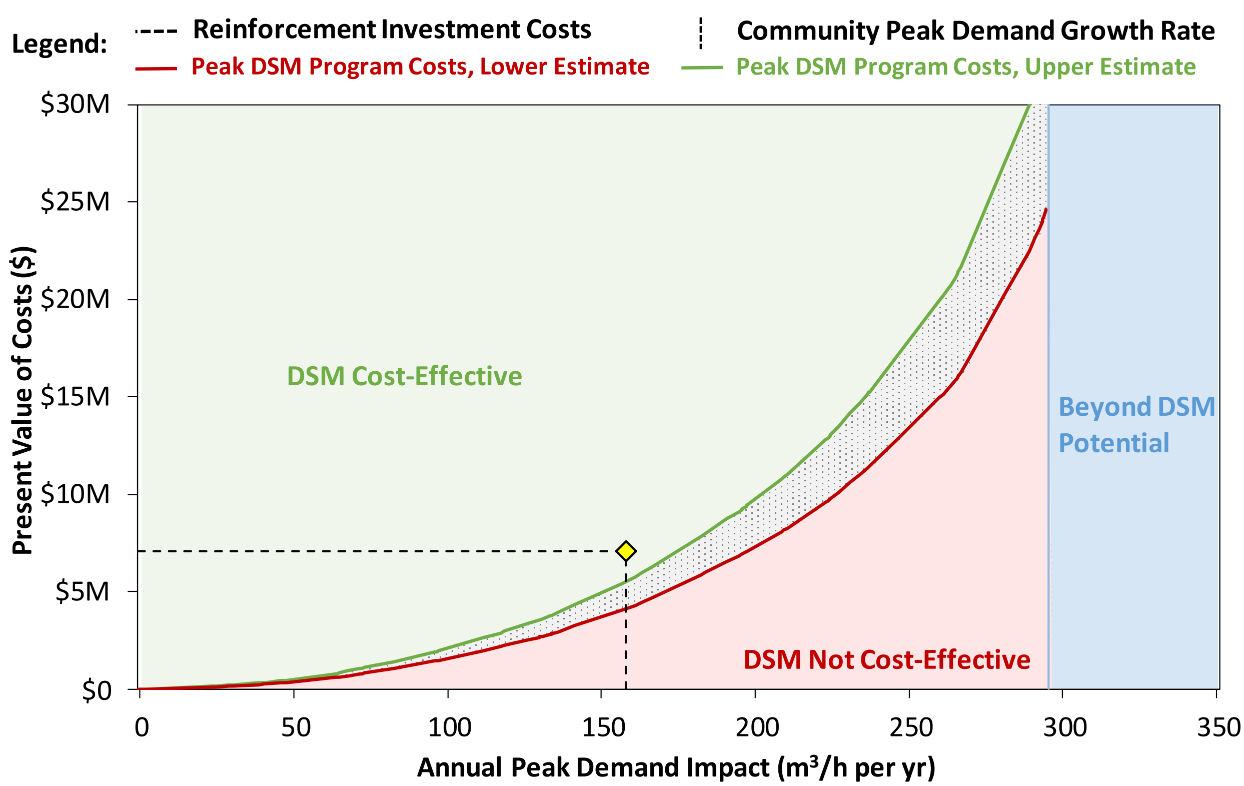
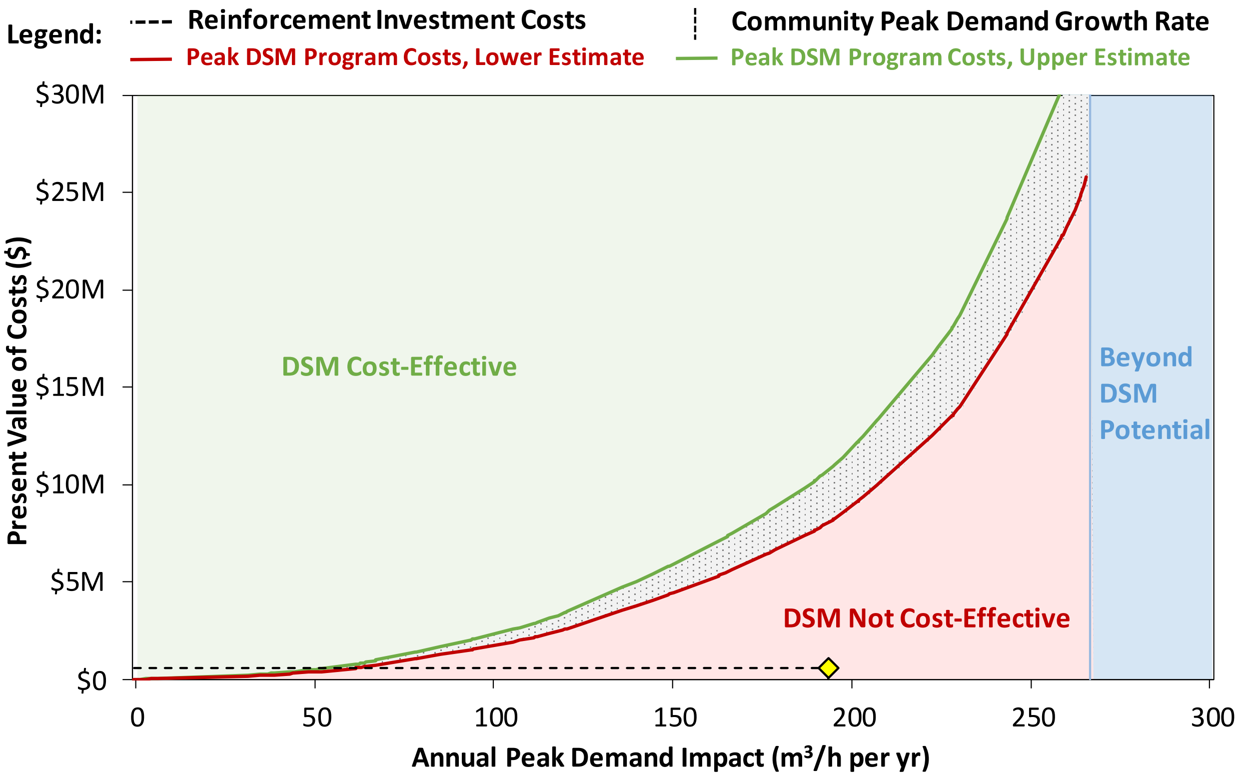


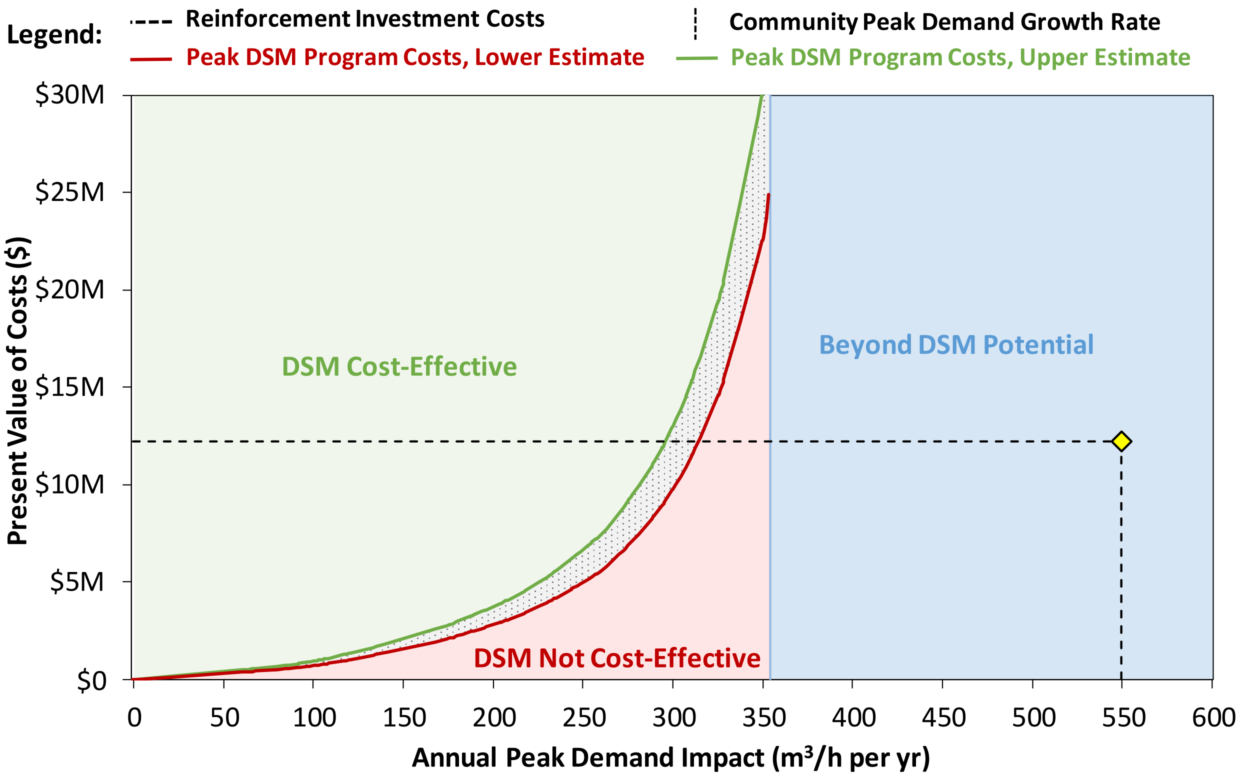
Exhibit ES 10 demonstrates that DSM is not always a cost-effective option for deferring reinforcement projects. In this case, Union Gas is planning to install 1.3 km of NPS 6" ST 6895 kPa pipeline to accommodate a growing community whose peak demand is increasing by approximately 194 m^3/h annually (0.7% per year). Although ICF's analysis suggests there is enough DSM potential to offset this growth, Exhibit ES 10 illustrates that it would not be cost-effective to defer the reinforcement project with a geo-targeted DSM program due to the lower capital costs of the project ($690,000) relative to the cost of the geo-targeted DSM.

Exhibit ES 10: DSM Supply Curve for Reinforcement Project in Union's North Region



A third scenario could also arise when comparing a reinforcement project to a geo-targeted DSM program aimed at reducing peak demand: there may not be enough DSM potential to offset the peak demand growth rate of the community. Such a scenario is depicted in Exhibit ES 11, which compares the costs of a reinforcement project in Union Gas' southern region against the costs of a geo-targeted DSM program. This reinforcement project would involve the installation of 7.6 km of NPS 12" ST 6160 kPa pipeline at a cost of $14,100,000. However, the peak demand of the community is expected to grow by 2.6% annually (~550 m^3/h), while ICF's analysis suggests that a geo-targeted DSM program would only be capable of offsetting ~355 m^3/h of growth annually, or about 1.35% growth per year in this market (approx. 295 m^3/h) at the same NPV cost as the infrastructure investment project. For this scenario, a geo-targeted DSM program could not feasibly defer the reinforcement project, and would also not be practical from a financial perspective, as shown in Exhibit ES 11.

Exhibit ES 11: DSM Supply Curve for Reinforcement Project in Union's South Region

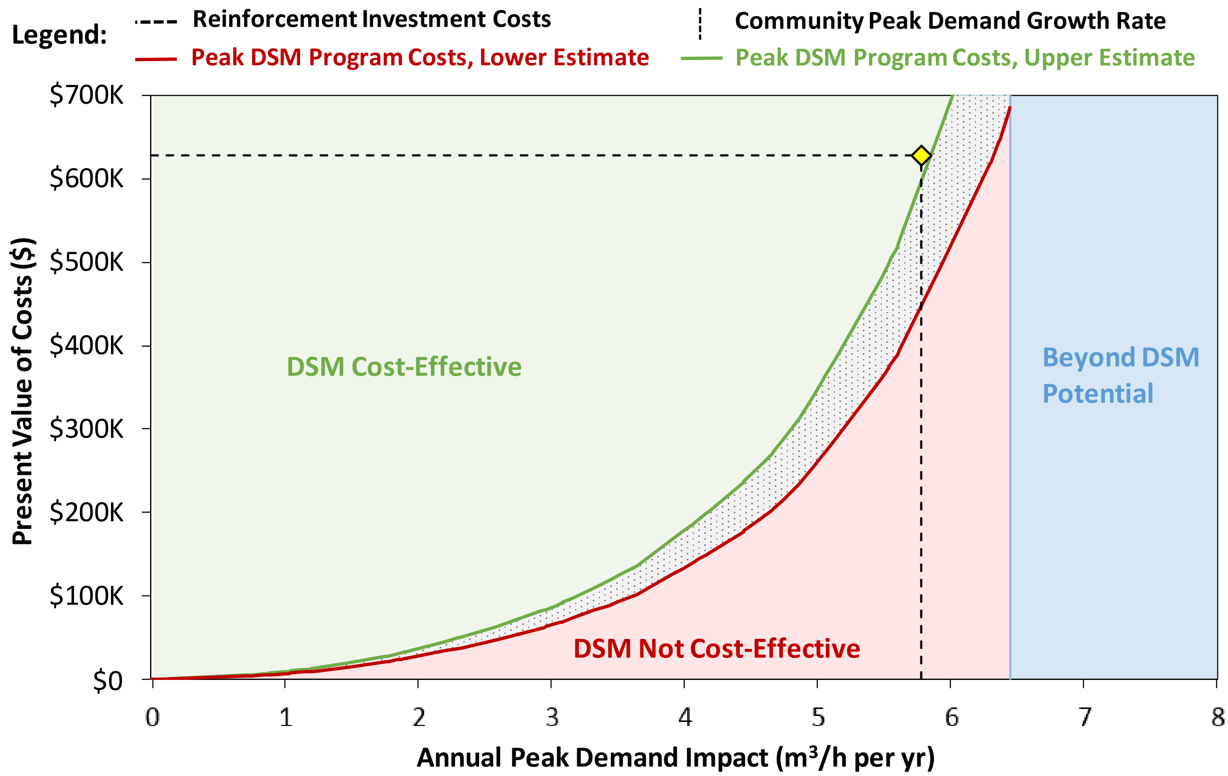


6.4.3 New Community Expansion

In addition to reinforcement projects, this study also investigated the potential for DSM to reduce capital costs for new community expansion projects. Of particular interest was the scenario where the demand from the new community is expected to be near the maximum capacity of a specific pipe size. Exhibit ES 12 shows the supply curve for such a hypothetical situation, wherein a NPS 2" steel pipe can be installed for $5,275,000, but would barely meet the new community's peak demand of 675 m^3/h. Alternatively, a NPS 4" steel pipe can be installed for $6,000,000 to comfortably meet the community's peak demand for many years to come (i.e. peak demand capacity of 4,160 m^3/h).

As shown in Exhibit ES 12, ICF's analysis suggests that DSM can cost-effectively offset annual peak demand growth of up to 5.8 m^3/h (or about 0.8% per year) in this market. If the peak hour demand for the community is growing faster than this rate, DSM would not be able to cost-effectively offset this growth.

Exhibit ES 12: Supply Curve for a New Community Project in Union's South Region



6.4.4 Summary of Results and Practical Considerations

The DSM measure supply curves reflect ICF's best current assessment of the costs and impacts on peak period demand available from DSM programs, while the facilities costs reflect the potential cost of serving incremental demand growth via investments in new facilities. As indicated in the summary analysis, there are facility investments where the incremental cost of reducing load using geo-targeted DSM programs may be lower than the incremental cost of the facilities, when compared strictly on a $ per m^3/h of incremental capacity provided. Hence, ICF's analysis of the potential for geo-targeted DSM to reduce peak hour demand growth suggests that under certain circumstances, there may be potential to reduce infrastructure investments using geo-targeted DSM programs.

However, there are a number of factors that need to be considered when making a project specific comparison of the cost of geo-targeted DSM and the cost of new facilities. These include:

- **Other benefits of facilities projects:** Many facilities projects provide additional reliability and flexibility to the natural gas distribution system in addition to increasing capacity. For projects where system reliability and flexibility are a significant factor in project design, the cost of the project needs to be allocated between the increase in capacity and the other project benefits.
- **Reliability of DSM programs to reduce peak demand:** To be useful in reducing infrastructure investments, geo-targeted DSM programs must achieve the same level of reliability as the infrastructure investments that they are designed to reduce. In the short

term, the uncertainty regarding the cost and reliability of geo-targeted DSM programs limits the Gas Utilities' ability to rely on geo-targeted DSM programs during infrastructure planning.

- **DSM penetration rates:** ICF's analysis suggests that, on average, the maximum achievable potential for peak demand savings from aggressive DSM implementation ranges from about 1.05% of peak demand per year in the Enbridge service territory to 1.24% of peak demand per year in the Union Gas service territory.[14] Based on the initial Enbridge facility investment data reviewed by ICF, when measured by the amount of incremental capacity being added, only about 20% of the planned facility expansion projects[15, 16] fall below this level.
- **Short Term Project Deferral:** In some cases where the projected growth in peak period demand exceeds the potential annual savings available from DSM, aggressive implementation of DSM might be sufficient to delay the project for a period of time without obviating the eventual need for the project. This would require implementation of the DSM program early in the facilities planning process in order to accumulate sufficient DSM savings to delay the facility. The cost-effectiveness of using DSM to delay the project depends to a significant degree on the length of time that the project can be delayed. A relatively short delay (one to three years) is unlikely to be useful due to the potential risk associated with the timing of the project and the need to monitor DSM program impacts, to ensure that the facilities are in place when needed.
- **Size of the geo-targeted community:** As with all DSM programs, geo-targeted DSM programs will benefit from economies of scale. As a result, as facility investment projects decline in size, the cost per m^3/h of peak demand savings from DSM is expected to increase, and smaller projects are unlikely to be cost-effective.

[14] Some of this potential may not be available for geo-targeted DSM programs due to its inclusion in pre-existing broad-based DSM programs.

[15] The planned facility expansion projects reviewed by ICF represent the list of potential expansion projects at a specific point in time, and should not be considered representative of future capacity expansion projects.

[16] The planned facility expansion projects represent a subset of facility investments, and include only those projects with the primary objective of meeting growth in natural gas demand.

7. Policy Considerations

ICF's review of the DSM and infrastructure planning processes at the Gas Utilities has identified several potential barriers or concerns to using DSM to help reduce infrastructure costs that should be addressed as policy issues. These include:

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.

2. Allocation of Risk

While the Gas Utilities are planning pilot studies and reviewing additional analyses, the Gas Utilities currently face uncertainty regarding the reliability of DSM programs designed to reduce peak demand. As a result, 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. 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?
- In order to provide reasonable assurance that the system will be available to meet demand, the Gas Utilities likely will need to develop plans for both geo-targeted DSM programs and the facility investments needed to meet demand if the DSM program is not successful. Alternatively, the DSM program will need to be oversized to minimize risk. In both cases, the Gas Utilities expect to incur additional costs that do not directly serve to meet system requirements. How do the Gas Utilities recover these additional costs?
- Who bears the risk if a geo-targeted DSM program does not lead to a deferral of an infrastructure investment? In this scenario, the utility would have invested in geo-targeted DSM activities without reducing facility 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?

3. Additional Research

Incorporation of DSM to reduce infrastructure investments as part of the normal infrastructure planning process will require additional certainty regarding the costs of geo-targeted DSM programs, and the impact of DSM programs on peak period demand, which will require additional data collection and research. The Gas Utilities will need regulatory approval to invest in, and recover the costs of the Advanced Metering Infrastructure (AMI) necessary to collect hourly data on the impacts of DSM programs and measures, as well as pilot programs necessary to determine the costs, impacts, and potential penetration rates for geo-targeted DSM programs.

4. Cross-Subsidization

In the current ‘postage stamp’ rate setting framework, the costs of new infrastructure are shared across customer classes, where all customers within a rate class pay the same amount throughout the franchise, except in specific cases where the Board has determined that a specific customer contribution is required for a particular new infrastructure. 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. This leads to policy questions that will need to be addressed:

- Is it appropriate to subsidize customer energy efficiency based on location, potentially providing incentives to customer on one side of the street, while denying these incentives to customers on the other side of the street, or in other nearby locations?
- Is it appropriate to provide energy efficiency subsidies to some new communities?

A geo-targeted DSM program designed to impact peak hour requirements may also result in differences in incentives available based on customer characteristics, leading to additional customer discrimination.

- Customers in smaller homes are less likely to be creating significant new gas loads, hence are less likely to be effective targets for geo-targeted DSM. This could result in a high proportion of the incentive payments being paid to customers that are generating the increased peak load.
- As a result, the overall costs of geo-targeted DSM may be inappropriately distributed to those customers who are in older, smaller, less efficient homes.

6. Incentives for Non-General Services Customers

Achieving the DSM market penetration necessary to defer investments in new facilities is likely to take several years of targeted DSM activity. Given the relative timeframes for DSM program implementation, geo-targeted DSM programs designed to reduce infrastructure costs for projects targeting new communities may need to target consumers that are not currently utility customers in order to reduce future demand by sufficient amount to achieve the program's objectives. This would not be allowed under the current DSM Framework. Is it appropriate to provide subsidies to consumers that are not currently customers of the utility, with the expectation that they might become customers in the future?

In addition, the need for much of the utility infrastructure investment, particularly on the Union system, is driven by the growth in Firm Transportation (FT) demand by large industrial customers. These customers contract for a specific level of pipeline capacity. However, in the Gas Utilities' experience, when these customers participate in DSM programs, they typically do not reduce the amount of FT capacity that they hold. Instead, they hold on to the capacity to make sure that they have access to the capacity in the future if their requirements increase, or use the capacity to meet new loads.

Hence a geo-targeted DSM program aimed at these customers might not have any impact on facilities requirements unless the program provides a sufficient incentive to the customer for the customer to release the (FT) capacity. This is likely to require different types of incentives and larger incentives than currently offered by the Gas Utilities, and would also require contracting terms that would discourage these customers from requesting additional capacity in the future.

7. Establishment of an Appropriate Leave-to-Construct (LTC) Budget Threshold for Geo-Targeted DSM Programs

Current guidance from the Board suggests that energy efficiency programs should be considered during the planning for each facility project brought before the Board as part of a Leave-to-Construct (LTC) application. The threshold for these LTC projects is currently $2 million, and as further outlined in the OEB Act 1998, part VI, Sect 90. However, developing, implementing, modelling and evaluating geo-targeted DSM programs as an alternative to a specific infrastructure project is expected to be both time consuming and require significant internal resources to perform the modelling, conduct the analysis, and investigate alternatives. Hence considering DSM as an alternative to infrastructure investments is likely to only impact those infrastructure projects with significant savings potential.

Once the initial study of the potential for DSM to reduce infrastructure investment is completed, and the Gas Utilities can provide the Board with a reasonable assessment of the costs and potential benefits, the Gas Utilities will provide a recommendation to the Board on the appropriate cost threshold and which facilities projects should be accompanied by a comprehensive assessment of the potential to reduce the project.

8. Appropriate Cost-Effectiveness Testing

Geo-targeted DSM programs may have benefits that combine the attributes of facilities planning and DSM programs, and should be evaluated considering the end user resource costs as well as the benefits of the DSM program on both energy consumption (Traditional DSM) and on their ability to reduce infrastructure investment based on the impact on peak hour/peak day demand (traditional facilities planning).

The Gas Utilities consider a combined approach to cost-effectiveness testing to be appropriate for geo-targeted DSM programs. Benefits should include the direct cost savings associated with the reduced infrastructure plus the annual energy savings associated with the program. Costs should consider both the ratepayer and societal costs of developing and implementing the targeted DSM programs. The cost-effectiveness criteria also needs to address the increase in risk associated with geo-targeted DSM programs. Ultimately the cost of the resource to the consumer should be a consideration in the various planning processes, with the affordability of energy supply a factor in the decision making process, and whether or not other resources are a viable alternative. If the deferral of a geo-targeted infrastructure project would result in fuel switching to a more expensive energy source this should be recognized and the additional costs to the end-use consumer fully valued.

8. Conclusions and Recommendations

To the best of ICF's knowledge, the ICF Integrated Resource Planning study conducted for the Gas Utilities provides the first comprehensive assessment of the potential to use broad-based and geo-targeted DSM as part of the natural gas distribution company facilities planning process in order to reduce investments in new natural gas utility infrastructure. The study includes a review of industry experience, an overview of the facilities planning process, an assessment of the potential impact of DSM programs on peak period demand, and the potential to use DSM to reduce new investments in utility infrastructure, and a review of the policy changes that would facilitate the incorporation of DSM into the facilities planning process. The primary conclusions of the study are developed based on the findings discussed earlier in this Executive Summary, and are summarized below.

8.1 Critical Elements of the Facilities Planning Process

Section 3 of this Executive Summary provides an overview of the facilities planning process. However, there are a few basic facilities planning principles that impact the potential for DSM programs to reduce infrastructure investments that need to be highlighted due to their importance. These include:

1) The primarily goal of facilities planning is to ensure that the utility infrastructure is of sufficient size and at the appropriate/required time to provide reliable natural gas service during peak demand periods[17] at system design conditions consistent with reasonable costs. Failure to meet peak period demands could result in loss of gas supply to firm utility customers during extreme cold conditions, leading to extreme social and economic costs to the utilities and their customers. As a result, the Gas Utilities and their customers have significant economic and social incentives to develop infrastructure based on upside uncertainty in the forecast rather than downside uncertainty.
2) The facilities planning process requires significant lead time in order to ensure that facilities are available by the time that the facilities are required. The facilities planning process is designed to identify expected requirements at about five years prior to the time at which the capacity will be needed in order to allow sufficient time for the project planning and design, regulatory review, and construction to be completed prior to the need for the facility.
3) ***There are significant economies of scale associated with the construction of facility investment projects.*** The cost of the incremental unit of capacity declines as the size of the project increases due to efficiency in planning, right-of-way and easement availability, mobilization costs, and labor and materials costs. As a result, downsizing a specific project

[17] The peak demand period for facilities planning used in our analysis is the peak hour, which typically occurs during the morning period between 7:00 AM and 9:00 AM. For planning purposes, the peak period demand is projected based on design day weather conditions, which typically occur on the coldest anticipated winter day, or design day. The duration of the peak period considered in the planning process depends on the type of infrastructure being evaluated. For individual service connections, the peak period used to size the service connection should be sufficient to meet the maximum customer demand. For certain distribution infrastructure projects serving a limited number of customers, the peak period used for facilities planning may need to be as short as 15 to 30 minutes, while larger transmission assets may be planned based on a longer time frame, potentially a 24 hour design day.

is likely to lead to only modest cost savings. In addition, if a project proves to be undersized relative to future system growth, additional facility investment projects are likely to be much more expensive than increasing the size of the initial project.

4) ***Facilities costs vary widely depending on specific circumstances.*** The ability to cost-effectively reduce infrastructure investments through the use of targeted DSM programs depends on the cost of the infrastructure that can be avoided, which vary significantly based on the size of the project, the characteristics of the existing system, and the areas impacted by the project. As a result, the cost-effectiveness of DSM programs as an alternative to infrastructure investments can differ widely for different infrastructure projects.

8.2 Summary of Industry Experience using DSM to Reduce Infrastructure Investments

ICF's review of existing DSM programs at North American gas utilities in other jurisdictions, documented in Section 2 of this Executive Summary, found that little to no activity has been undertaken that was designed to reduce transmission and distribution costs using targeted DSM and Demand Response (DR). In addition, measured data necessary to determine the potential impacts of DSM on new facilities requirements is generally unavailable. Overall, the review of industry experience found that:

1) The natural gas industry has extremely limited experience integrating DSM into the facilities planning process, and in using targeted DSM to reduce investments in infrastructure projects. ICF's review of existing DSM programs at North American gas utilities in other jurisdictions found that no activity has been undertaken that was designed to deferred transmission and distribution costs using targeted DSM and DR.
   - ICF did not identify any natural gas utilities outside of Ontario that actively consider the impact of DSM programs on peak hour or peak day demand forecasts used for facilities planning. Since this study was initiated in October of 2016, a few gas utilities have begun to consider these impacts. However, these efforts remain in the very early stages.
   - Gas utilities in other jurisdictions have expressed concerns about the reliability of the DSM impacts as an infrastructure investment alternative due to the lack of information on the measured impacts of DSM on peak hourly demand.[18]

[18] Note that, to date, no natural gas utilities have actually measured the impact of DSM programs on peak period demand.

2) ICF also assessed activity in the electric power industry. While some progress has been made in the electric power industry to defer transmission and distribution costs using targeted energy efficiency, differences in utility cost structure, duration of peak period requirements, and availability of data on DSM impacts leads ICF to the conclusion that geo-targeted DSM programs are likely to be more cost-effective for the electric industry than they are for the natural gas industry, and that the electric industry experience provides only relatively limited value as an example for the gas industry.

The differences between the electric system and the natural gas system include:

- The electric industry can achieve greater infrastructure cost savings from similar DSM and DR measures, due to the higher cost infrastructure of the industry.
- The difference in risk tolerance between the industries, for capacity shortage, also increases the attractiveness of DSM and DR for infrastructure deferral and avoidance in the electric industry relative to the natural gas industry.
- In addition, the ability to accurately measure the impact of DSM due to the advanced metering capabilities of electric utilities reduces risk associated with the reliance on DSM to displace electricity infrastructure. The lack of metered customer data makes estimating peak hour demand impacts difficult for gas utilities and increases facility planning risks.

8.3 Potential for Targeted DSM to Impact Infrastructure Investment

Due to the lack of industry experience, and the lack of measured data on DSM peak period load impacts, ICF conducted most of the research into the potential for DSM to impact infrastructure requirements by extrapolating existing data on DSM program impacts from annual data to peak hourly period data based on building modeling, and other theoretical analysis. While we view the analysis as robust, there remains significant uncertainty, particularly on the cost and reliability of using DSM to reduce infrastructure investment. Hence, our conclusions should be treated as preliminary until additional research is completed.

The assessment of the potential for DSM to impact infrastructure investments is reviewed in Sections 5 and 6 of this Executive Summary. The primary conclusions from ICF's study related to the potential impacts of DSM measures and programs are summarized below:

- ***1) DSM can impact peak hour natural gas demand and natural gas demand growth.*** While there is little to no measured data on actual peak hour impacts of natural gas DSM programs, ICF's analysis indicates that many, but not all, DSM measures should be expected to have measurable impacts on peak hour natural gas demand:
  - In general, industrial measures are most cost-effective at reducing peak hour demand, followed by commercial sector measures, and then residential sector measures.
  - Space heating is important from a winter peak hourly demand perspective, even in the industrial sector. Measures that result in space heating savings, such as air sealing, insulation, central heating systems and boiler measures, contribute disproportionately to winter peak hour savings.

    - Adaptive thermostats lead to annual gas consumption savings but initial analysis shows that this measure may increase winter peak hour demand since HVAC systems are recovering from temperature setback during this period.
        - Residential building modeling indicates that adaptive thermostats lead to a significant increase in winter peak hour demand.
        - Commercial building modeling suggest that adaptive thermostats lead to increases in winter peak hour demand in the commercial sector as well but the impact is much smaller than the residential sector due to the lower applicability of this measure in the commercial sector and the diversity of operating schedules in the different types of commercial facilities being considered.
        - During the winter peak day, adaptive thermostats lead to increased demand during other non-setback hours as well since it can take several hours to heat up a building's entire thermal mass.
    - At least a portion of the demand impacts from other measures with a controls component may not be coincident with winter peak hourly demand.
    - Modeling of tankless water heaters suggests that they can increase peak demand for an individual customer during the relatively short periods that they are in use. However, when impacts are considered on an hourly basis and aggregated across many customers within a community (i.e. such that the diversity of water usage profiles are considered), tankless water heaters are expected to lead to peak demand reductions.
    - Based on the building modeling conducted by ICF, DSM is not expected to shift the timing of the hourly peak demand.

- Based on ICF's initial assessment of the potential to reduce peak hour demand using DSM, it appears possible that some infrastructure investments may be reduced through the use of targeted DSM.

    - ICF's analysis suggests that geo-targeted DSM programs would have the potential to offset demand growth by up to about 1.2 percent per year, before consideration of DSM program and measure costs.
    - ICF's analysis suggests that DSM may be able to cost-effectively defer infrastructure investments in certain situations where annual peak hour demand growth is relatively low and project costs per unit of demand are relatively high.

- Based on ICF's initial assessment of the likely costs of reducing peak hour demand using DSM, the number of infrastructure projects that appear likely to be cost-effectively reduced by targeted DSM is expected to be limited.
    - Opportunities to reduce facility investments in a cost-effective manner through the use of geo-targeted DSM are likely to be limited due to the cost of geo- targeted DSM programs relative to the cost of many infrastructure projects.
    - The maximum penetration rate of DSM programs appears likely to be lower than the rate of growth in areas where a significant share of new infrastructure projects are indicated. As a result, DSM programs targeted at infrastructure projects in these regions are more likely to be able to delay a specific project than to eliminate the

need for the infrastructure project altogether. The cost-effectiveness of geo-targeted DSM programs decreases as the delay in project implementation becomes shorter.

- There is likely a minimum size for facility investments where geo-targeted DSM programs could be cost-effectively implemented due to DSM program development, implementation, and monitoring costs.

8.4 Policy and Planning Changes Needed to Facilitate Use of Targeted DSM to Impact Infrastructure Investment

Facilities planning and DSM planning processes are currently independent of each other, and operate under different regulatory structures. Given the range of differences between the existing planning process, and the needs and objectives of the facilities planning process, it is likely that implementation of geo-targeted DSM will require a specific planning and regulatory framework, determined for the express purpose of deferring natural gas infrastructure.

Integrating the potential for DSM to reduce infrastructure requirements into the facilities planning process will require significant changes in policy, as well as changes in the utility planning process. These issues are explored in more depth in Section 4 (Utility Planning) and Section 7 (Policy) of this Executive Summary. The primary conclusions include:

1. ICF's review indicates that changes in Ontario energy policy and utility regulatory structure would be necessary to facilitate the use of DSM to reduce infrastructure investments. These changes would include:

    - Cost recovery guidelines for overlapping DSM and facilities planning and implementation costs, and criteria for addressing DSM impact risks.
    - Approval to invest in, and recover the costs of, the Advanced Metering Infrastructure (AMI) necessary to collect hourly data on the impacts of DSM programs and measures.
    - Changes in the approval process for DSM programs to be consistent with the longer lead time frame associated with facilities planning.
    - Clarification on the allocation of risk associated with DSM programs that might or might not successfully reduce facility investments.
    - Guidance on cross subsidization and customer discriminations inherent in geo-targeted DSM programs that do not provide similar opportunities to all customers.
    - Guidance on how to treat conflicts between DSM programs designed primarily to reduce investment in new infrastructure and DSM programs designed to reduce carbon emissions or improve energy efficiency.
    - Guidance on how to treat uncertainty associated with energy efficiency programs outside the control of the Utilities that impact peak period demand.

- There are a number of differences between the DSM and facilities planning process that must be reconciled in order to factor in geo-targeted DSM to reduce facility investments.

    - This includes differences in risk and reliability criteria, cost-effectiveness criteria, program assessment and planning timeframes.
    - The linkages between DSM planning and facilities planning are currently 'passive' rather than 'active', and are not sufficient to actively integrate geo-targeted DSM programs into the facilities planning process.

  - Underestimating facilities requirements can lead to significant operational problems for the gas utility (such as widespread customer outages during cold weather), leading to a very risk adverse planning process for facility investments. Given the lack of data on actual impacts of DSM measures on peak hour demand, DSM is generally considered a high risk alternative to facility investments that would be inconsistent with facilities planning criteria.
- Differences in the risk profile between facilities planning and DSM planning create significant challenges in incorporating DSM programs into the facilities planning process. Underestimating facilities requirements can lead to significant operational problems for the gas utility, leading to a very risk adverse planning process for facility investments. Given the lack of data on actual impacts of DSM measures on peak hour demand, DSM is generally considered a high risk alternative to facility investments that would be inconsistent with facilities planning criteria.

8.5 Recommendations for Additional Research

The use of DSM to reduce investments in natural gas facilities remains relatively untried and untested. While ICF has identified areas where there is potential to use DSM to reduce infrastructure investments, there remains significant uncertainty in both the potential and the cost of achieving that potential. There is little to no actual measured data on DSM program impacts on peak period demand for natural gas, and there are no significant real world examples that ICF can point at to indicate that DSM can be used effectively for this purpose.

As a result, there is currently a fundamental disconnect between the limited risk acceptable to the 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 the Utilities would be able to rely on DSM to reduce infrastructure investment as part of the normal business planning process:

- The lack of real measured data creates significant uncertainty in the evaluation of the potential to use DSM to reduce infrastructure investments and increases the risk (hence the cost) of using DSM to reduce infrastructure investments.
- The lack of reliable program implementation cost data for geo-targeted DSM programs makes accurate cost comparisons between facilities and DSM unavailable.

Hence, one of the most important conclusions from this study is that ***additional research is necessary before the Gas Utilities would be able to rely on DSM to reduce new infrastructure investments as part of the standard utility facilities planning process***. This research needs to include:

- ***Collection of hourly demand data:*** Collection and evaluation of measured hourly demand data needed to more accurately assess the impact of DSM measures and programs on peak period demand is needed to determine the cost and implementation potential of DSM measures and programs before the Gas Utilities would be able to rely on DSM to reduce new infrastructure investments as part of the standard facilities planning process. This will require installation of Advanced Meter infrastructure installation (AMI), and automated meter reading (AMR) capability. Until actual hourly data is available, the Gas Utilities will not be in a position to accurately determine the potential cost-effectiveness of using DSM as an alternative to infrastructure investments.

- **Assessment of the reliability of using targeted DSM to reduce peak hour demand growth:** The risk associated with relying on DSM to reduce peak hour demand is one of the major stumbling blocks in using DSM to reduce infrastructure investments. ICF expects that development of specific pilot studies that test the ability of the utility to offset demand growth using DSM pilot programs will be the best approach to resolving these reliability issues.
- ***Assessment of the cost of geo-targeted DSM implementation*****:** The cost per participant of implementing geo-targeted DSM programs is expected to be significantly higher than the costs of implementing system-wide DSM programs. The additional costs are based on the smaller program scale associated with geo-targeted DSM programs, the tailored nature of targeted DSM programs, and the need for additional monitoring and evaluation. Based on available information, and on our experience with DSM program implementation, these costs are estimated at 1.5 to 2 times higher than typical DSM program costs. However, until actual pilot studies are developed and implemented, the actual increase in costs will be unknown. The magnitude of these costs may determine whether or not geo-targeted DSM programs can be cost-effective.

I. Introduction

Integrated resource planning (IRP) has been considered in the regulatory environment in Ontario since the early 1990s. Since 1995, Enbridge Gas Distribution and Union Gas Ltd. (the Gas Utilities) have engaged in demand side management (DSM) activities that have generated significant natural gas savings across all rate classes. These DSM savings may also have resulted in less facility investments by broadly reducing gas demand growth. This study is aimed at improving our understanding of the nexus between gas DSM and natural gas distribution facility investments.

Recently, the role of geographically targeted (geo-targeted) DSM programs in the facilities planning process was raised during the EB-2012-0451 proceeding as part of the review of the Enbridge GTA Reinforcement Project. The Ontario Energy Board (OEB) followed up on this question in its 2015-2020 DSM Framework issued December 22, 2014. In this decision, the OEB directed the:

> Gas utilities to each conduct a study, completed as soon as possible and no later than in time to inform the mid-term review of the (2015-2020) DSM Framework.[19]

Further, the OEB stated that it:

> Expects the gas utilities to consider the role of DSM in reducing and/or or deferring future infrastructure investments far enough in advance of the infrastructure replacement or upgrade so that DSM can reasonably be considered as a possible alternative.[19]

Enbridge included a proposed study scope in EB-2015-0049. The study scope was designed to evaluate the potential of broad-based or geo-targeted DSM programs to avoid or defer (reduce) infrastructure costs while meeting the forecasted hourly peak gas demand. Further the study would examine whether such broad-based geo-targeted DSM programs can be consistent with the primary goals and principles of facilities planning – that is to provide reliable natural gas service at reasonable costs.

The study scope was reviewed by interveners and ultimately approved by the OEB in the DSM multi-year decision. The Gas Utilities engaged ICF to conduct this study.

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[19] OEB, Report of the Board: Demand Side Management Framework for Natural Gas Distributors (2015-2020), p. 36, Dec. 22, 2014. https://www.oeb.ca/sites/default/files/uploads/Report_Demand_Side_Management_Framework_20141222.pdf

1. Study Scope and Objectives

In the OEB's 2015-2020 DSM Framework report, it set three goals for ratepayer funded DSM:[20]

1. **Assist consumers in managing their energy bills through the reduction of natural gas consumption:** Customers who participate in the DSM programs should see a decrease in their energy bills.

2. **Promote energy conservation and energy efficiency to create a culture of conservation:** DSM programs should advance conservation and energy efficiency, beyond the program participants, to the broader public in Ontario.

3. **Avoid costs related to future natural gas infrastructure investment, including improving the load factor of natural gas systems:** Gas utilities are expected to consider DSM initiatives in the context of facilities planning so that reducing demand for natural gas also helps avoid or defer (reduce) future infrastructure costs.

The goal of this study is to assess the extent to which DSM can be leveraged by the Gas Utilities to reduce future gas facility investments, to identify potential approaches and obstacles to using DSM to reduce future gas infrastructure costs, and to lay out the process necessary for further development of the OEB's third goal. This includes the following key study areas:

1. Reviewing other jurisdictions' gas distribution IRP policies and experiences
2. Outlining the Gas Utilities' current DSM and facilities planning process and using this to identify current barriers to considering DSM as an option to reduce facility investments
3. Determining how DSM impacts peak day and peak hour demand, including the following areas of potential overlap between DSM and facilities planning:
   a. **Intersection 1:** Broad-based DSM and facilities planning
   b. **Intersection 2:** New subdivision and community facilities planning
   c. **Intersection 3:** Geo-targeted DSM and reinforcement facilities planning
4. Identifying the modifications needed to the current facilities planning and DSM planning processes to include consideration of DSM as an option to reduce facility investments
5. Recommending how and when the above facilities planning process modifications could be implemented.

This study focused on the potential for DSM to impact distribution facilities planning. While DSM can impact the need for transmission assets upstream of the utility service territory, an analysis of these impacts was beyond the scope of this study. Hence, the study did not evaluate the impact of DSM on natural gas storage infrastructure or upstream transmission infrastructure for either utility.

The study also excluded the impact of DSM on transmission capacity serving demand downstream of the Utility service territory. Hence we did not consider the impact of DSM on any large transmission systems (such as the Dawn Parkway system), or the impact that changes in load due to DSM might have on large transmission systems. Most of the demand growth likely

[20] EB-2014-0134 Report of the Board: Demand Side Management Framework for Natural Gas Distributors (2015-2020), p .5, December 22, 2014.

to impact requirements for new Dawn Parkway capacity will be determined by customer demand outside of the service territories of the Gas Utilities.

Given the ultimate goal of identifying a process to ensure that DSM is considered as an option to reduce facility investment costs, the study attempted to identify the barriers to using DSM, and to propose processes to address and overcome them.

The scope of the study included the following items:

- **Review of Industry Experience:** ICF conducted a literature review to evaluate how other leading utilities address issues related to broad-based DSM and facilities planning, and issues related to the impact of DSM programs on new subdivision and new community planning. ICF also interviewed leading North American utilities identified as having experience working on integrated resource plans.
- **Assessment of DSM Impacts on Peak Hour and Peak Period Requirements:** ICF leveraged the results of the 2016 OEB Conservation Potential Study (OEB CPS)[21] and developed end-use load profiles and hours-use factors to estimate the winter peak period demand (peak period demand) breakdown and the achievable winter peak hour demand (peak hour demand) savings from DSM. ICF also developed DSM supply curves to assess the costs of DSM implementation against the peak demand savings.
- **Application of DSM Supply Curves to Facility Investments:** ICF leveraged the results of the DSM impacts analysis to understand the potential of DSM programs to reduce facility investments (i.e., delay the need for additional capacity for new construction and facility investments). As part of this step, ICF worked with the Gas Utilities to identify appropriate hypothetical case studies based on specific examples of distribution facility investments. Information from these case studies that informed the analysis included project costs, current and forecasted capacity requirements, and the distribution of energy consumption by building type. It is important to note that this study has focused on distribution facilities, not on upstream transmission, storage, or contract gas supply options. (For that matter, the report does not address on-system storage investment.) DSM supply curves were used to compare the costs of peak hour demand savings through the implementation of DSM against the cost of distribution facility investments.
- **External Review and Stakeholder Engagements:** Throughout the IRP study, ICF and the Gas Utilities consulted with a Study Advisory Group (SAG) to gain insights on IRP processes for similar utilities, and to discuss the study approach and findings. The SAG was made up of members from other North American gas utilities, the Independent Electricity System Operator (IESO), the academic community, and an OEB staff observer. The study benefited from the hands-on experience of staff in other organizations that have undertaken system-wide resource planning. The external review brought a broad perspective and helped to ensure the quality of the study across the several specialized fields involved.
- **Transition Plan:** The OEB directed the Gas Utilities to work jointly on the preparation of a proposed transition plan that outlines how to include DSM as part of future facilities planning activities within the Utility Planning Process. This study provided critical insights used by the

[21] ICF, Natural Gas Conservation Potential Study: Final Report, completed on behalf of the Ontario Energy Board (OEB), July 7, 2016. https://www.oeb.ca/oeb/_Documents/EB-2015-0117/ICF_Report_Gas_Conservation_Potential_Study.pdf

Gas Utilities during the development of the Utilities' Transition Plan. The Transition Plan was filed with the OEB by the Gas Utilities as a companion document to this report and it is also included here as an appendix.

2. Report Organization

This report is organized and presented as follows:

- Section II presents a review of industry experience and an evaluation of how other leading utilities address issues related to broad-based DSM and facilities planning, geo-targeted DSM and reinforcement facilities planning, and issues related to the impact of DSM programs on facilities planning for new subdivisions and communities.
- Section III presents an overview of the natural gas facilities planning and DSM planning processes.
- Section IV presents the estimated impacts of broad-based DSM on natural gas peak hour demand.
- Section V presents the assessment of the potential for DSM to impact facilities planning.
- Section VI presents the overall study conclusions and recommendations

II. Review of Industry Experience

As the first step in this study, ICF conducted an extensive review of industry experience integrating DSM and facilities planning by North American natural gas local distribution companies (LDCs). This review consisted of two primary components:

- A literature review to evaluate how other leading utilities (gas and electric) 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
- Interviews with a cross-section of leading North American natural gas utilities identified as having experience working on integrated resource plans

The following subsections discuss other gas utilities' experiences using DSM to reduce facility investments, and the differences between natural gas and electric utilities' planning processes identified during this process.

1. Literature Review Summary

ICF evaluated how other leading utilities address issues related to broad-based DSM and facilities planning (passive deferral), geo-targeted DSM and facilities planning (active deferral), and issues related to the impact of DSM programs on new subdivision and community facilities planning.

Fifteen IRP report and IRP report style documents were reviewed. The focus was on gas, and combined gas/electric utilities. Exhibit 1 shows the full list of IRP reports included in the literature review.

Based on ICF's review and assessment of these documents, the most relevant utility experiences (i.e., the utilities with the most insights on integrating natural gas DSM into the IRP process) are highlighted. Additional information is provided on each utility, including utility size and heating degree days for a representative population centre in each utility's service territory. This allows for a comparison of the size and heating degree days for these utilities to those of the Gas Utilities. The bottom rows of the table include the utility size and heating degree day values for the Gas Utilities for comparison purposes only.

Overall, the utilities with a similar number of heating degree days to the Gas Utilities include Northern Utilities, Vermont Gas Systems, and to a lesser extent Colorado Spring Utilities and FortisBC. Most of the reviewed utilities are much smaller in customer size than the Gas Utilities. On a utility size perspective, the gas utilities that are most similarly sized include FortisBC and Questar Gas.[22]

The table also summarizes the treatment of DSM within the IRP process for each utility. ICF found that, in most IRP reports, DSM was treated as a reduction of the total annual demand forecast based on the results of an achievable potential study and cost-effectiveness

[22] The differences between the Gas Utilities and the reviewed utilities in both size and climate do not reduce the usefulness of the review with respect to the state of the industry and the lessons available to the Gas Utilities from the experiences at other utilities, but do reduce the applicability of any direct comparisons between utilities.

framework. In some cases, DSM was treated in the IRP report as a resource option to meet customer demand. The treatment of DSM is discussed in further detail in the subsequent sections of this literature review.

Exhibit 1: IRP Reports Included in the Literature Review

#	Utility	Year	Jurisdiction/ Region	Natural Gas	Elec.	Utility Size (# of customers)[23]	2015 Heating Degree Days[24]	Representative City used for HDD	Pre-screened DSM, treated as demand reduction	DSM treated as a resource option	Notes
1	Avista Utilities	2016	Washington, Idaho, Oregon	Y	Y	78,723	2,559	Boise, ID	Y		Iterative process, DSM screen uses IRP avoided costs
2	California Utilities – Joint	2016	California	Y	Y	10,963,409	1,025	Sacramento, CA	Y		For long term planning purposes, not an IRP
3	Cascade Natural Gas	2014	Washington and Oregon	Y		273,365	1,839	Portland, OR	Y		DSM screen based on utility cost test
4	Colorado Springs Utilities	2011	Colorado	Y	Y	196,803	2,958	Denver, CO	Y		Missing information on methodology
5	ConEdison	2012	New York	Y	Y	865,888	2,407	New York, NY	Y		Successfully used targeted DSM on electric side
6	FortisBC	2014	British Columbia	Y	Y	980,000	2,904	Vancouver, BC	Y		DSM screen includes non-energy benefits
7	Intermountain Gas	2010	Idaho	Y		334,546	2,559	Boise, ID		Y	Missing information on methodology
8	New Mexico Gas Company	2012	New Mexico	Y		514,734	2,016	Albuquerque, NM	Y		Missing information on methodology
9	Northern Utilities	2015	Maine and New Hampshire	Y		60,656	3,725	Portland, ME	Y		Missing information on methodology
10	Northwestern Energy	2012	Montana	Y	Y	188,745	2,184	Billing, MO	Y		Missing information on methodology
11	Northwest Natural	2016	Oregon and Washington	Y		707,680	1,839	Portland, OR	Y		NW Natural plans to treat DSM as resource option in 2018 IRP
12	Oklahoma G&E	2015	Oklahoma	Y	Y	866,796	1,637	Oklahoma City, OK	Y		Electric focused IRP
13	Puget Sound Energy	2015	Washington	Y	Y	794,792	2,021	Seattle, WA		Y	Added non energy benefits to TRC
14	Questar Gas	2013-2014	Utah and Wyoming	Y		975,375	2,431	Salt Lake City, UT		Y	Limited to approved DSM activities

[23] Natural Gas Annual Respondent Query System (2017). (EIA-176 Data through 2015). Independent Statistics & Analysis. U.S. Energy Information Administration. Accessed January 23, 2017. http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RPC&f_sortby=ACI&f_items=*MULTIPLE*&f_year_start=2015&f_year_end=2015&f_show_compid=Name&f_fullscreen

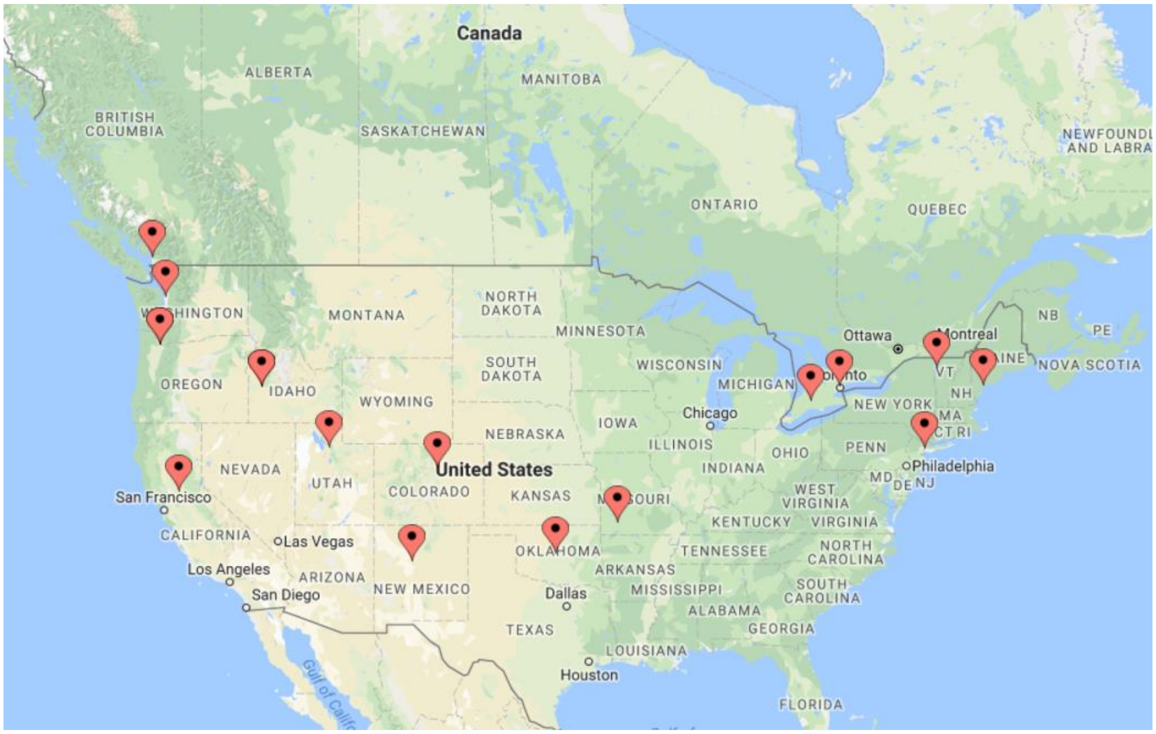
[24] Weather Data Depot (2017). EnergyCAP, Inc. Accessed January 23, 2017. http://www.weatherdatadepot.com/

#	Utility	Year	Jurisdiction/ Region	Natural Gas	Elec.	Utility Size (# of customers)[23]	2015 Heating Degree Days[24]	Representative City used for HDD	Pre-screened DSM, treated as demand reduction	DSM treated as a resource option	Notes
15	Vermont Gas Systems	2012	Vermont	Y		48,977	3,882	Burlington, VT	Y		DSM screen based on societal cost test, includes non-energy benefits
-	Enbridge Gas Distribution - Central	2015	Ontario	Y		2,113,848[25]	3,782	Toronto, ON	For comparison of utility size and heating load only		
-	Enbridge Gas Distribution – Eastern						4,428	Ottawa, ON			
-	Union Gas - Southern	2015	Ontario	Y		1,417,788[26]	3,914	London, ON			
-	Union Gas - Northern						5,156	North Bay, ON			

[25] 2015 Yearbook of Natural Gas Distributors (2016). Ontario Energy Board. Accessed January 23, 2017
[26] 2015 Yearbook of Natural Gas Distributors (2016). Ontario Energy Board

The geographic distribution of the jurisdictions represented in this literature review and the IRP reports noted above are shown in Exhibit 2.

Exhibit 2: Jurisdictions Represented in Literature Review



2. DSM Impacts on Peak Demand

2.1 Peak Demand Impacts of DSM Programs

Facilities planning relies on forecasts of peak natural gas demand, including the peak hourly demand that the system will be expected to transport. As a result, an assessment of the impacts of DSM programs on peak hour demand is a critical step in evaluating the potential savings in infrastructure investment available from DSM. This section discusses the utility experience in measuring the impacts of gas DSM programs on peak hour demand.

Avista Utilities has attempted to quantify the deferred distribution capacity benefits from natural gas DSM. Since 2001, Avista DSM programs in Washington and Idaho have offset the peak day load of about 8,380 customers, and Avista said that they are aiming to quantify the magnitude of the peak day savings. One possibly effective approach, according to Avista, considers the costs involved with recent or future reinforcement or capacity upgrade projects, and calculates the increased system capacity. However, at the time of the 2016 IRP report, Avista had not tracked upgraded system capacity and, therefore, an accurate calculation would be difficult to make due to the interconnectedness of the natural gas distribution system. This is a similar situation to the Enbridge system. The benefits of deferred distribution capacity are a one-time cost that would be allocated across the lifetime of a usual distribution upgrade (35 years) as an avoided payment. The 2016 Avista IRP report indicates that the utility aims to include this component in its 2018 IRP report, after consultations.[27]

The 2014 FortisBC IRP report incorporated DSM into load forecasting, but did not incorporate it into supply side/distribution planning. As part of its system capacity planning considerations, FortisBC identified that some DSM measures, known to reduce annual gas consumption, can require short periods of high consumption. Examples include setback thermostats and tankless water heaters. Although these measures result in savings on an annual basis, they can shift demand and have an adverse effect on peak hour demand. For measures such as setback thermostats, the utility noted that the gas demand could be concentrated into specific times of the day. The FortisBC IRP report indicates that more research is required into different energy-efficiency equipment installations to determine the impacts on peak demand.[28]

In Puget Sound Energy's IRP report, DSM is included as a supply side resource to meet forecasted peak day demand over a 20-year planning timeframe. The cost curves for DSM options include annual energy impacts and peak day demand impacts. However, the IRP report did not document DSM measure load profiles, or the process the utility used to develop DSM peak day impacts. The utility measures the impacts of DSM programs by charting the trends in natural gas program expenses and savings over time. Based on these trends, and with input from advisory groups, Puget Sound Energy develops new savings and expenditure targets every two years.[29]

2.2 Passive Deferral in Other IRP Reports

This section discusses the gas utilities that account for passive deferral—peak demand impacts due to broad-based DSM—in IRP reports, and discusses reasons why active deferral is not often pursued. The primary objective of broad-based DSM is to obtain participant and societal savings through a reduction in annual consumption of natural gas. These DSM programs have an indirect impact on the need for distribution infrastructure.

ICF found that most IRP reports discussed DSM from a program perspective, and treated it as a modification to their load forecast, often incorporating DSM into an achievable potential study. There is little mention of the use of DSM in supply side/distribution planning, or in quantifying peak day or peak hour benefits. Some utilities that did include peak day demand impacts, however, include Puget Sound and Vermont Gas Systems.

According to the Dunsky report, which studied many gas IRP reports, most utilities likely don't include DSM peak day or peak hour impacts within their analyses due to limited information. Without these considerations, DSM cannot be an alternative to supply side resources. The report also stated that, for DSM to become an alternative to supply side capital investment, a longer capacity planning horizon is needed for system reinforcements. If this were reflected in the IRP report, DSM could effectively act as a specific alternative assessment, and a capital project could be considered as a candidate for deferral based on the estimated deferral value.

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[27] Avista. (2016). 2016 Natural Gas Integrated Resource Plan, p. 50-51, Ch. 3
[28] FortisBC. (2014). 2014 Long-Term Resource Plan, p. 122-123, Ch. 5
[29] Dunsky Energy Consulting. (2015). Demand Side Management In Resource Planning, p. 27

The infrastructure deferral value of the project could also be included as a benefit in the cost-effectiveness testing for the project.[30]

Avista recently modified its approach to DSM by integrating the potential study results with its integrated resource planning process. While the potential study would typically use pre-IRP avoided costs in the cost-effectiveness screening of measures for the potential study, Avista's modification combines the potential study avoided costs with the IRP-derived avoided costs. The utility did this by first calculating avoided costs without DSM resources and then by reducing forecasted daily demand by the preliminary DSM supply curve that was created and a new set of avoided costs computed by the IRP model to serve the load requirements. The process is repeated until the avoided cost streams match the successive IRP iterations. Avista's IRP report noted that it influences the purchase of conservation measures by deploying general DSM measures, but does not depend on estimates of peak day demand reductions from conservation to solve near-term distribution system constraints.[31, 32]

The Questar Gas IRP report discussed the factors used in long-term residential usage modeling for Utah and Wyoming. The effects on annual use per customer from the company's energy-efficiency programs, based on past and projected participation are incorporated into the model. The utility uses the software, SENDOUT, a linear programming optimization model, to evaluate supply side and demand side resources. DSM is included as a discrete resource option with levelized cost curves in the utility's gas supply modeling. The model includes an analysis of different scenarios, each involving increased program administration costs and different participation values. Overall, the results of the utility's 2013 energy-efficiency programs are an example of an appropriate and cost-effective resource, compared to other supply sources; however, the analysis performed on DSM activities was limited only to utility-approved DSM activities.[33]

In addition to reviewing traditional resource alternatives, Intermountain Gas analyzed potential DSM measures as a solution for "constraint" areas. Further detail on how DSM was incorporated into the utility's resource optimization model is not provided in its IRP Report; however, it was noted that the utility will continue to evaluate the effectiveness of additional DSM programs.[34]

The New Mexico Gas Company IRP report, filed for the period of 2012-2022, briefly mentions that DSM programs have the potential to impact the utility's peak day demand forecast with increased participation and technology improvements. From an overall system planning standpoint, energy-efficiency gains were not yet significant enough to offset peak day demand. The utility did not provide any methodology for the assessment of DSM.[35]

One utility that includes the impacts of broad-based DSM programs into its IRP report is Vermont Gas Systems (VGS). VGS indicated in its 2012 IRP report that efficiency programs are forecast to reduce gas purchases and contribute to delayed transmission investment over the

[30] Dunsky Energy Consulting. (2015). Demand Side Management In Resource Planning, p. 40-43
[31] Avista. (2016). 2016 Natural Gas Integrated Resource Plan, p. 138
[32] Avista. (2016). 2016 Natural Gas Integrated Resource Plan Appendices, p. 211
[33] Questar Gas Company. (2013). Integrated Resource Plan. p. 3.2-3.4
[34] Intermountain Gas. (2010). Integrated Resource Plan 2011 – 2015, p. 11-12
[35] New Mexico Gas Company. (2012). Natural Gas Integrated Resource Plan 2012-2022, p. 14

term of the plan. VGS takes the savings from DSM and applies them to their daily load requirements model used to calculate firm and interruptible sales. The DSM savings are subtracted from the historically derived heating use per customer per day value to reduce the projected level of supply resources and lower transmission expansion needs. When making supply considerations in the supply side planning for the utility, DSM was assessed for three different scenarios based on lower or higher participation and costs. These scenarios were built based on VGS' existing programs; however, the results of the analysis were not based upon an achievable potential study, so there may be additional cost-effective opportunities that were not identified. VGS includes broad-based DSM peak day impacts in their IRP as well. These peak day DSM savings are applied to reduce customer sales and the projected level of supply resources; however, no information is provided in its IRP report on the methodology used to determine these impacts.

Puget Sound Energy treats DSM as a distinct resource option in its IRP report. Program measures are tested by the utility in bundles, from lowest to highest cost along a supply curve until the system costs are minimized. The utility only includes demand side resources implemented to date and use a gas portfolio for long-term planning purposes. Savings targets from DSM are adjusted every two years and projected gas energy savings from DSM resources are based on these target values.

In the NW Natural 2016 IRP report, the utility notes that the DSM avoided costs now include capacity resource costs, which weren't included in its 2014 IRP process. However, the utility still treats DSM as a reduction to the final load forecast prior to the supply resource choice optimization and risk analysis. The utility notes that the tentative process for their 2018 IRP report is to have avoided costs become an output of an integrated resource choice optimization model rather than an input to the supply side resource choice optimization analysis. This would create a fully integrated resource stack, including both supply and demand side resources.[36]

2.3 Active Deferral in Other IRP Reports

This section discusses gas utilities that account for active deferral (peak demand hour or peak demand day savings due to targeted DSM) in other IRP reports. Targeted DSM programs can potentially reduce the amount of new gas capacity required or delay the need for new capacity. This could reduce the level of investment in new utility infrastructure, lower utility rates, and avoid the potential for excess capacity in the system.

A 2015 Northeast Energy Efficiency Partnerships (NEEP) study notes that, although there are few if any publicly documented examples of a gas utility using geo-targeted DSM, there is growing interest in this topic. The study notes that active deferral could help to reduce pipe congestion issues in parts of New England where natural gas is required for electric generating stations. The literature review suggested that there is a link between active deferral and policy mandates, particularly in regard to electric utilities. An analysis of the unique challenges faced by natural gas utilities compared to electric utilities is discussed further below in this report.

In Dunsky's review of DSM in IRP reports, it is noted that, although there are no recent examples of targeted DSM at Vermont Gas System, an act passed by the Vermont Legislature

[36] NW Natural. (2016). 2016 Integrated Resource Plan, p. 168, Ch. 5

in 2005 introduced integrated least cost transmission and distribution planning requirements for electric utilities. Efficiency Vermont subsequently launched geo-targeted electric DSM with success. The utility selected pilots for geo-targeted DSM on the basis of existing concerns for system capacity; as a result, the utilities were not required to pursue system upgrade projects in the pilot project areas.[37]

Avista's gate station modelling process compared forecasted peak day gate station demand to the contracted and operational capacities at each gate station. Where forecasted demand exceeded contracted or operational capacities, further analysis was conducted to address the deficiency. The utility indicated that a peaking factor, representing a ratio of the peak hourly flow and the total daily flow at gate station, was used to convert daily loads to hourly loads. Avista lists the gate station analysis as including targeted DSM programs along with expansion to the system and/or system enhancements. However, despite the mention of targeted DSM as a potential to address gate deficiency, no additional details or examples of this were provided in the IRP report.[38]

Puget Sound Energy's IRP report provided a 10-year projection of facility investments required to meet forecasted demand. The infrastructure and delivery planning process looks at potential alternatives in constrained delivery areas, including adding an energy source, strengthening feed to the local area with new or higher pressure mains, equipment modification, and load reduction. The most appropriate alternative is selected through a cost-benefit analysis of the various project options. Conservation is listed by the utility as an alternative solution under load reduction; however, there are no examples provided on the use of conservation to defer capital investments for the gas delivery network.

The NW Natural 2016 IRP report states that for supply side and demand side options to be compared on a level playing field, more must be learned about the reliability of targeted DSM peak hour savings, the cost and timing at which the savings accrue, and how the savings are measured. The IRP report acknowledges that targeted DSM initiatives take multiple years to plan and execute, and discusses a proposal to plan distribution system reinforcements further out in time to enable consideration of a targeted DSM strategy. The IRP report notes that a location-specific DSM cost-effectiveness test that focuses on peak savings in a specific geographic area is needed, and conceptually discusses a targeted DSM pilot which may be filed with the Public Utility Commission of Oregon (OPUC) by late 2017 or early 2018. This program is aimed at addressing constraints in the NW Natural distribution system and the IRP report provides an illustrative-only example of such a program. The example provided discusses a targeted DSM offering as an alternative to the 2017 Clark County Camas Loop reinforcement project, using pipeline modeling software to find areas of weakness in the local distribution system.[39]

According to its 2012 IRP report, ConEdison (ConEd) is in the process of evaluating demand response programs to reduce peak daily natural gas demand and defer capital investments that would otherwise be required to reinforce the natural gas system. ConEd provides greater

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[37] Dunsky Energy Consulting. (2015). Demand Side Management In Resource Planning, p. 31-32
[38] Avista. (2016). 2016 Natural Gas Integrated Resource Plan, p. 109-110
[39] NW Natural. (2016). 2016 Integrated Resource Plan, p. 31, Ch. 6

information in its IRP report on electric targeted DSM, for which the utility calculated the deferral value of construction and uses this amount to budget for more targeted DSM programs.[40] ConEd identifies constraint areas for targeted DSM with a 10-year load forecast analysis. The analysis is used to create a load-relief plan wherein the projects targeted are those needed in the next five years, and those where the load reduction required is less than 3-4% of the forecasted peak load. The utility also uses both the deferral value and the net present value of avoided energy costs, capacity and avoided line losses to set the maximum price of a targeted DSM project.[41]

2.4 Cost-Benefit Analysis

This section discusses the cost-benefit analysis (i.e., TRC, SCT, PACT/UCT) used by other gas utilities to evaluate the cost-effectiveness of natural gas conservation programs. Based on ICF's analysis of IRP reports, peak demand impacts for DSM programs are not considered in any cost-effectiveness screening analysis. Most utilities were found to have DSM pre-screened for cost-effectiveness through an achievable potential study.

The Cascade Natural Gas Corporation uses a utility cost test (UCT) approach to evaluate the cost-effectiveness of its natural gas conservation programs, rather than the traditional TRC method. Based upon the guidance provided by the Washington Utilities and Transportation Commission Docket UG-121207, TRC analysis alone was found to have potential bias against conservation programs. This is because TRC analysis is often unbalanced or incomplete and omits the conservation's risk reduction value. In addition, TRC analyses often don't account for the downward price pressure from reduced demand and any associated non-energy benefits.

The UCT was compared to the TRC in a Nexant economic and achievable potential study done for Cascade. The total natural gas savings potential result was much higher with the UCT than the TRC since the UCT allowed more measures to surpass the cost-effectiveness threshold than the TRC. This was because the UCT considers only the incentivized portion of a measure's incremental cost. Cascade believes using UCT enables natural gas demand side resources to approach a possible comparison with supply side resources on a level playing field.[42]

The Vermont Gas System IRP report treats DSM as an annual load forecast reduction based on historical trends and expected growth in DSM programs. The DSM forecast is based on a societal cost test (SCT), which includes natural gas externalities, a 15% non-energy benefits adder, low-income non-energy adjuster, and social discount rate.[43]

In Puget Sound Energy's IRP report, DSM cost effectiveness was assessed on the basis of the TRC, with added considerations for environmental conservation credit, non-energy resource benefits, and secondary energy benefits. In this case, the credits and benefits are used as a reduction in levelized costs of conservation.

As outlined in the Avista IRP report, a mixture of UCT and TRC was used to develop the economic potential for the conservation potential study conducted by the utility. UCT was used

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[40] ConEdison. (2012). Integrated Long-Range Plan, p. 83
[41] Dunsky Energy Consulting. (2015). Demand Side Management In Resource Planning, p. 33
[42] Cascade Natural Gas. (2014). 2014 Integrated Resource Plan, p. 65, 68, 71
[43] Vermont Gas Systems. (2012). Revised Integrated Resource Plan 2012, p. 2-3, Ch. 5

for Washington and Idaho; TRC for Oregon. Certain measures in Oregon were required by law and were therefore incorporated without being subject to any cost-effectiveness testing. Note that the listing of measures included energy audits, which do not generate energy savings in of themselves. The utility noted that they have been working to quantify deferred capacity benefits from natural gas conservation (i.e., DSM impacts on peak day demand) but that it is currently difficult to do so given that they do not track upgraded system capacity or avoided low pressure customers (areas experiencing low pressure during winter at unpredictable times given diverse load profiles of customers).[44]

2.5 Advanced Metering

This section discusses the prevalence of advanced metering/smart meters in natural gas utilities that conduct IRP reports, and how this information is used in the IRP process. ICF assessed available IRP report sources and found most reports either do not include reference to advanced metering in the report results, or fail to mention the use of advanced metering in their IRP process.

Advanced metering/smart meter data can be a very effective tool to develop geo-targeted DSM programs. Currently, natural gas utilities can identify peak constraint areas at a gate station level, but further granularity is limited. Smart meter data allows utilities to identify specific areas, where the utility's distribution system is close to capacity during peak events, for future geo-targeted DSM opportunities thereby reducing the need for facility investments in those specific areas. Real-time data from smart meters also allow for effective evaluation, measurement, and verification (EM&V) of demand response programs. Utilities can analyze consumption conditions and then compare baseline customer usage to actual program results.

The 2016 California Gas report mentions an advanced meter infrastructure (AMI) project by SoCalGas that determines shifts in residential load growth and helps to inform the projected residential natural gas demand. Customers are provided with more information about their daily and hourly gas use, so the meters are also expected to encourage customers to use gas more efficiently.[45]

In the 2014 FortisBC IRP report, the utility listed advanced metering technology in response to an actionable item from its 2010 Resource Plan. The IRP report stated that the FortisBC Energy Utilities Codes and Standards Group had worked with the Canadian Gas Association and with Measurement Canada to advance thermal metering for gas-heated buildings.[46] Thermal metering, also known as heat metering, measures incoming and outgoing temperatures and the flow of heat exchange liquid to calculate the amount of thermal energy used. In addition, an action item in the utility's 2014 long-term resource plan included monitoring and examining advancements in gas metering infrastructure.

ConEdison plans to deploy 4.7 million electric smart meters over a six-year period starting in 2017. Its 2015 advanced metering infrastructure business plan notes that AMI will include the introduction of enhanced demand response programs and enhanced "smart" rate plans, which

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[44] Avista. (2016). 2016 Natural Gas Integrated Resource Plan, p. 46
[45] California Gas and Electric Utilities. (2016). 2016 California Gas Report, p. 75
[46] FortisBC. (2014). 2014 Long-Term Resource Plan, p. 11

will allow the utility to offer alternative rate structures to reward energy conservation during periods of peak demand. Other electric utilities have increasingly deployed the use of AMIs, with an estimated 50 million smart meters deployed in the U.S. as of 2014 (43% of American homes). In ConEdison's benchmarking study, six peer utilities had electric AMI, but only two had installed gas AMI.

In Canada, SaskEnergy is the only gas utility known to be installing AMI gas modules across its service territory.[47] In the U.S., SoCalGas was the first major natural gas only utility to implement AMI gas modules, starting installations in 2012.[48] There are few other examples of gas AMI, largely due to the difficulty in justifying the business case for AMI without time of use (TOU) rates.

3. Distribution Facilities Planning

3.1 Gas Supply and Facilities Planning Process

Overall, most gas utilities conduct their gas supply and facilities planning processes in a similar manner. They assess all available supply and demand side options available to determine the least cost and least risk mix needed to meet the demands of their customer base. Demand for gas and supply access are the main drivers of gas supply planning (including upstream transmission pipeline contracting). Gas demand also drives investments in distribution facilities, but also the need to upgrade aging pipe is an important consideration.

The most common planning concerns between gas supply and facilities planning found in the integrated resource plans were: unknown regulatory risks, delivery risks, and price risks. Regulatory risks include restrictions on pipeline expansion and climate change legislation. Price uncertainty in the short term is related to gas price volatility, while in the long term issues include increased demand of natural gas for electric generation. Most utilities accounted for such issues by conducting a reasonable range of scenarios forecasting the future load growth of natural gas demand. A discussion of some of the natural gas supply and facilities planning processes and issues in specific jurisdictions is provided below.

In its IRP report, Avista defines its demand areas by the service territories and the pipelines that serve them. Planning issues are similar to other IRP reports, with the potential for greater demand due to electricity generation and natural gas vehicles, price issues, and pipeline system constraints due to approvals. As is the case with most other IRP reports, demand forecasts were created for differing key drivers, such as price and weather. With this mix of low/high growth and low/high demand scenarios, Avista compares the scenarios in which peak demand is not able to be met with existing resources. In this report, Avista noted that the timing and

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[47] Advanced Metering Infrastructure, SaskEnergy. Accessed January 23, 2017. http://www.saskenergy.com/residential/AMI.asp
[48] SoCalGas Advanced Meter Semi Annual Report – August 2013. Accessed January 26, 2017. https://www.socalgas.com/regulatory/documents/a-08-09-023/SoCalGas-Advanced-Meter-Semi-Annual-Report-83013.pdf

extent of the resource deficiencies are such that the utility has more time to monitor the situation and take action on resource additions.[49]

The Vermont Gas Systems IRP report states that their planning process is on-going, both on the growth and supply side. The market growth in the economic value of natural gas is based on balancing the competitiveness of natural gas in the market and expansion to new customers and new service territories. Vermont Gas Systems creates its system market growth and load forecast by evaluating market growth and economically feasible expansion projects in five distinct categories: residential new construction, residential main extension, residential infill, commercial, and industrial. Some common planning issues that arise include selecting an appropriate feasibility horizon for expansion funding projects. In the case of residential main extension funding, the utility found that a 10-year horizon is best to balance the impacts of new and existing customers. The IRP report notes that a shorter period would have a lower rate impact on existing customers but could result in less expansion. A longer period would allow more projects to be economical but have a greater upward pressure on rates in the early years of a project.[50] This balance of several objectives in the long and short term is an important consideration for the Gas Utilities in Ontario's regulatory environment as well.

NW Natural established a 10-year forward system planning framework with regards to distribution system planning. It expects to consider potential demand side resources for projects with timing needs beyond three years as a shorter timeframe is considered insufficient for the implementation of demand side resources. The choices for distribution improvements assessed by the utility include pipeline looping (constructing a new pipeline near an existing one), upsizing (replacing an existing pipeline with one with a greater diameter), uprating (increasing the pressure within a pipeline), and installing extra compression capacity. Depending on the scenario, each option has unique costs, benefits, timing, and risks. The best option is the least cost, safest, and most reliable option for ratepayers. Once a preferred supply side solution is determined, NW Natural assesses demand side alternatives for possible viability.[51]

3.2 Safety, Reliability and Performance Design Criteria

Of paramount importance to gas distribution utilities are system safety, reliability, and performance design criteria (e.g., maximum and minimum allowable operating pressures, maximum gas velocity, and acceptable losses). These design criteria are important to consider for utilities who use DSM to reduce facility investments because of the probabilistic nature of DSM efficacy in reducing peak period consumption and system flow. By contrast, investments for system reinforcement may be required regardless of the demand savings that can be achieved through DSM.

In the FortisBC IRP report, operating pressure limitations are identified for pipeline upgrades based on the number of dwellings within a distance of 200 m from the pipeline. As the density of homes increases, the safety factor for the pipeline is increased as per Clause 4.3.2 of CSA Standard Z662, Oil and gas pipeline systems. Pipeline stress is also required to be monitored

[49] Avista. (2016). 2016 Natural Gas Integrated Resource Plan, p. 12
[50] Vermont Gas Systems. (2012). Revised Integrated Resource Plan 2012, p. 1-1, 3-3
[51] NW Natural. (2016). 2016 Integrated Resource Plan, p. 220-221, Ch. 5

for safety and reliability performance in areas of water crossings and seismic event sites for the mitigation of natural hazards. For ease of operation and public safety, the pipeline system is operated at a maximum operating pressure of 60 psig for FortisBC Energy service territory (FEI) and 80 psig for the FortisBC Energy Vancouver Island (FEVI) service territory.[52]

Avista's pipeline system is comprised of both high and intermediate pressure mains (at 90-500 psig and 5-60 psig, respectively). These operating pressures are selected by the utility for ease of maintenance and operation, and public safety. Pipeline solutions for increasing capacity include looping, upsizing, and uprating. Safety and pipeline regulations can prohibit the uprating of pipelines (increase of maximum allowable operating pressure) as increasing the pressure can produce leaks or other costly repairs. The maximum allowable pressure increase is therefore dependent on a review of the pipeline's integrity.[53]

Vermont Gas Systems evaluates design day loads when determining transmission expansion required to existing system capacity, and uses key parameters, such as the maximum inlet pressure, minimum delivery pressure, and maximum velocity of gas in the pipeline. The transmission system capacity is limited by the pressure entering the system. Therefore, while the utility had explored the option of increasing its maximum operating pressure, it found that it is not operationally preferred as it would require its minimum contractual delivery pressure from TransCanada to be increased as well.[54]

Similar discussions of safety limitations for uprating pipelines was mentioned in other integrated resource plans as well, such as those for Colorado Springs, Questar Gas, and Intermountain Gas. Discussions of safety limitations for the Gas Utilities are usually present in their asset plans, rather than their long-range plans.

The NW Natural IRP report indicates that the industry standard for establishing the design capacity of a new pipeline is based on a maximum 20% pressure drop. According to the utility, this allows the pipeline to handle a reasonable amount of growth and can prevent the need for near-term system reinforcements. For high-pressure distribution systems, a 40% pressure drop is an indicator for reinforcement or an alternative solution. Other considerations for reinforcement are demanded by facilities where near-term growth is expected. Examples of growth include planned construction of a new road, a new subdivision, or industrial development. The IRP report notes that for regular distribution systems, a minimum distribution pressure of 10 psig or lower is an indicator for reinforcement or an alternative solution.[55]

4. New Subdivision Facilities Planning

The extension of gas distribution facilities to new communities and subdivisions poses unique challenges for IRP that are addressed later in this report. Regarding other jurisdictions' policies and experiences, ICF could not find any significant information regarding new subdivision

[52] FortisBC. (2014). 2014 Long-Term Resource Plan, p. 120.
[53] Avista. (2016). 2016 Natural Gas Integrated Resource Plan, p. 131-132.
[54] Vermont Gas Systems. (2012). Revised Integrated Resource Plan 2012, p. 6-2
[55] NW Natural. (2016). 2016 Integrated Resource Plan, p. 225, Ch. 7

facilities planning in the documents reviewed. The typical IRP report looked at high-level system issues and did not go into the details of local planning investment plans or issues.

Avista noted in its IRP report that the high-level aggregated methodology for supply and demand forecasting in previous IRP reports created issues that resulted in deficiencies at individual gate stations. For this reason, Avista developed a gate-by-gate analysis to calculate forecasted peak day gate station demand and compared this to each station's capacities.[56] Similarly, Cascade Natural Gas modified its demand forecast approach to increase the level of granularity from a zonal level down to a city gate level. The utility developed linear regression models for each city gate, and models are now built up with more granularity.[57]

5. Climate Change Policy Impacts

Ontario recently passed legislation and regulation to impose a price on carbon starting in 2017. On May 19, 2016, the Ontario government released Ontario Regulation 144/16 – The Cap and Trade Program (Cap and Trade Regulation). The regulation took effect on July 1, 2016 and imposed a carbon price on more than 80% of emission sources in Ontario starting January 1, 2017. Given the velocity of energy and climate policy development in Ontario and the lack of detail in the Climate Change Action Plan (CCAP) and Long Term Energy Plan (LTEP), there is considerable uncertainty in forward demand for natural gas in the short (2016-2020), mid (2021-2030) and long term.

Any assessment of forward demand for natural gas in Ontario will need to include consideration of:

- The price of carbon that will be imposed via regulation
- The impact of any price of carbon on existing residential, commercial, and industrial customers' demand
- The impact of the measures defined within the CCAP on natural gas demand
- The impact of possible changing policies vis-à-vis climate change and cap and trade

Assessing the impacts of climate change policy on natural gas consumption and demand in other jurisdictions shows what is possible in Ontario when making an assessment of forecasted natural gas consumption and demand.

For example, Avista models carbon legislation into its IRP report as an incremental price adder for potential policy implications. Avista estimated that carbon legislation would occur at the federal level through the Clean Power Plan, and at the state level through carbon cap and trade. To account for carbon legislation, Avista created a range of carbon pricing possibilities and analyzed the impacts of three separate carbon tax sensitivities on natural gas demand forecasts.[58]

In its IRP report, Colorado Springs Gas discussed the long-term implications of new climate change legislation on the energy production and consumption landscapes. The utility noted that

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[56] Avista. (2016). 2016 Natural Gas Integrated Resource Plan, p. 109-110
[57] Cascade Natural Gas. (2014). 2014 Integrated Resource Plan, p. 17
[58] Avista. (2016). 2016 Natural Gas Integrated Resource Plan, p. 5, 25

a cap and trade structure seems to be the most likely framework for greenhouse gas legislation. The impacts of this legislation on load growth forecasting was determined by creating specific alternative price forecast scenarios that captured the influence of potential carbon emission legislation. The utility also relied on technical advisory committee input to develop carbon emission reduction sensitivities into the modeled scenarios.[59]

Puget Sound Energy's IRP report included the impacts of CO_2 pricing into the modelling of demand side resources. The utility found that the inclusion of CO_2 into its base case load forecast scenario increased conservation by approximately 20% in 2018-2019. It was also noted that the inclusion of CO_2 costs increased conservation targets in 2015 compared to 2013 by making the overall levelized cost of gas higher.[60]

The Vermont Gas IRP report included carbon costing in its natural gas base forecast, and briefly discussed carbon costing as being the leading factor in incremental natural gas demand in the electricity generation sector beginning in 2020 ($22/ton in 2020, increasing to $54/ton in 2036).[61] The IRP report also discusses natural gas vehicles (NGVs) as being part of a solution to climate change for Vermont.

ConEdison also commented on the increase for natural gas due to higher use of natural gas vehicles.

In its 2014 IRP report, Cascade Gas noted that carbon legislation played an important factor in its long-term natural gas load forecast, while past IRP reports found carbon legislation impacts on the short-term consumption forecast to be minimal.[62]

In the Questar Gas IRP report, the utility noted that revised environmental policy will result in additional costs to conduct business. The report also discussed the reporting of greenhouse gases; however there were no quantified impacts on the natural gas load forecast provided in Questar's IRP report.[63]

6. Electric Power Industry Experiences

In 2015, NEEP conducted a study of the role of energy efficiency in the deferral of transmission and distribution (T&D) system investments. The report focused primarily on infrastructure deferral in the electric power industry, for which there are a number of examples of electric utilities using passive and geographically-targeted efficiency programs to accomplish that. The electric utilities that have demonstrated active deferral include Bonneville Power Administration, ConEdison, Efficiency Vermont, and PG&E. Additional insights were provided in a State and Local Energy Efficiency Action Network document. Some of these initiatives are summarized below:[64, 65]

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[59] Colorado Springs Utilities. (2011). 2011 Gas Integrated Resource Plan, p. 1.11
[60] Puget Sound Energy. (2015). 2015 PSE IRP, p. 33, Ch. 7
[61] Vermont Gas Systems. (2012). Revised Integrated Resource Plan 2012, p. 2-3, Ch. 2
[62] Cascade Natural Gas. (2014). 2014 Integrated Resource Plan, p. 55
[63] Questar Gas Company. (2013). Integrated Resource Plan, p. 33-34, Ch. 4
[64] Neme C. & Grevatt J. (2015). Energy Efficiency as a T&D Resource
[65] The State and Local Energy Efficiency Action Network (2011). Using Integrated Resource Planning to Encourage Investment in Cost-Effective Energy Efficiency Measures

- **Bonneville Power Administration (BPA):** BPA, which operates in the U.S. Pacific Northwest, recently invested in a demand response initiative in the San Juan Islands in response to reliability concerns after an underwater power cable was severed. This five-year initiative kept loads on the remaining cables at appropriate levels prior to the addition of a new cable.
- **Pacific Gas & Electric (PG&E):** In California, PG&E passed a bill in 2013 that required utilities to assess the locational benefits and costs of distributed resources, including efficiency. PG&E looked specifically at growth areas in its jurisdiction with a projected in-service date of three years and an operating deficiency of 2 MW or less to focus on the most achievable deferral projects. Ultimately, PG&E was able to select four deferral projects to reduce load growth.
- **ConEdison (ConEd):** ConEd, which operates in New York State, found the need for system reinforcement to keep up with forecasted supply constraints. From 2014 to 2015, it invested $200 million into customer and utility side investments and new capacitors.
- **Efficiency Vermont:** A change in the Vermont legislature prompted electric utilities to initiate pilots for geo-targeted DSM. As a result of increased investments into these pilot programs, intensive account management for large customers, and a small commercial direct install program, Vermont utilities were not required to pursue system upgrade projects in three of its four service regions.
- **Northwest Power and Conservation Council:** This regional planning organization was required by law to develop an IRP process that prioritized the role of DSM in meeting electrical demand, rather than treating demand side resources on an equal footing with supply resources. The 2010 IRP process subsequently determined that 85% of its projected growth in demand over the next 20 years could be met through energy efficiency.

NEEP noted that the successes in the electric power industry were largely due to policy mandates, effective communication between infrastructure planners/engineers and staff responsible for the administration of energy-efficiency programs, senior management buy-in, and a focus on smaller load reduction areas where it was easier to plan and execute a DSM opportunity.

Overall, the majority of electric power industry investments into energy-efficiency programs were driven by some type of regulatory requirement or legislative mandate. While some initiatives are still in a preliminary planning stage, others have achieved enough savings to reduce facility investments. For example, ConEd estimated geo-targeted efficiency investments from 2003-2010 would produce $3 in benefits for every $1 in costs. The NEEP report provided further policy recommendations for utilities, such as requiring a least cost approach to meeting T&D needs, requiring long-term forecasts of T&D needs, establishing screening criteria for non-wire alternatives, and promoting equitable cost allocation across regional rate-payers for non-transmission alternatives. The study also noted that, while these findings were targeted for electric power utilities, the conclusions drawn should be applicable to natural gas infrastructure as well.[66] While this conclusion is important to note, natural gas utilities have found practical applications of this to be difficult, as discussed in the following section.

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[66] Neme C. & Grevatt J. (2015). Energy Efficiency as a T&D Resource

7. Summary of Natural Gas DSM Impacts on Facilities Planning

Through its review of existing gas DSM impacts across North American utilities, ICF found that, while advancements have been made in the electric power industry to reduce transmission and distribution costs, there has been no equivalent reduction on the gas side. Of the available approaches used by various utilities in assessing DSM impacts, the challenge lies in integrating DSM into the IRP process so that all benefits of DSM are captured, including the impact of DSM on peak hourly demand. Based on the review of other jurisdictions, there are very limited examples of this. In most cases, the savings from DSM programs were focused on annual savings and any impacts due to DSM were assessed as an annual demand reduction.

Some IRP reports have made improvements to better integrate DSM into the IRP process. For example, Avista was the only utility that used an iterative process in its cost-benefit analysis modeling of DSM measures by using IRP avoided costs in the economic screening of DSM options. In the Puget Sound IRP report, the utility had DSM integrated into the IRP modeling process as a supply side resource to meet forecasted peak day demand over a 20-year planning timeframe. To have a greater understanding of DSM impacts on peak demand, there is a need to understand and define gas DSM hourly load profiles. The utilities that included DSM peak day impacts included Vermont Gas System and Puget Sound. However, peak hourly impacts were not assessed and the IRP reports for these utilities did not provide further information on the methodology used to develop the peak day impacts or any information on the DSM measure load profiles.

While it is important to acknowledge the discussion by many parties that the concepts used for electric T&D deferral in the IRP process can be applied to natural gas utilities, there are some important distinctions between electric and gas planning processes. FortisBC is one natural gas utility that shared some of its practical application observations in an IR response with its commission during the FEU Long Term Resource Plan application. The utility noted that resource plans for electric utilities must acquire power and capacity from the market, or produce their own power and capacity. As such, the electric utility planning process examines the trade-offs between various generation and electrical purchase options. On the other hand, gas utility companies that acquire supply resources from the market have a different purpose. These utilities focus planning efforts on assessing delivery infrastructure requirements and, based on forecasted load, the resource plan examines the potential for demand side resources and options for adding pipe, storage, and compression.[67]

For most gas utilities, the largest portion of peak demand is for space and water heating. This makes it more difficult to implement targeted programs to shift peak demand since the natural gas system acts to store energy. Gas utilities have noted that the attractiveness of storage is much higher as the increased costs for capacity resources are not as severe as they are for electric utilities, which typically do not have a sophisticated and cost-effective method to store the product.[68]

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[67] FortisBC. (2014) Response to the British Columbia Utilities Commission IR No. 1. Accessed January 23rd 2017. https://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/140619_FEU_2014_LTRP_BCUC_IR1_Response_FF.pdf

[68] FortisBC. (2014). 2014 Long-Term Resource Plan. p. 90, Ch. 4

ICF noted that there are more examples of electric utilities using geo-targeted DSM than gas utilities. However, in almost all cases these initiatives had a legislative mandate acting as a catalyst. In general, utilities have many hurdles to overcome before they are able to successfully implement a targeted DSM strategy. For example, the gain or loss of a large customer could have a significant impact on targeted DSM projects. As a potential issue, NW Natural discussed how the addition of a large customer might require a project to be moved up in time to meet the immediate needs. On the other hand, expected new developments could have ended up not being built or delayed due to certain economic circumstances.[69]

The other challenge in implementing geo-targeted DSM includes coordination with various levels of government agencies to allow enough time to consider targeted DSM options. There are some instances where a targeted infrastructure deferral project could be more cost-effective than an infrastructure reinforcement project; however, due to a lack of sufficient lead time provided by government agencies, it is not possible to plan, design, and execute a DSM program. In this case, the implementation of a more expensive alternative may be required to reliably meet customer needs.

Another major concern is how to properly quantify the costs and benefits associated with targeted DSM. In the electric power industry there is a greater push towards advanced metering infrastructure deployment. Some advances have been made on the gas utility side but these are considerably less so than those made in the electric utility industry.

Based on the jurisdictional review of other gas and electric utilities, it appears as though natural gas utilities across North America have yet to properly assess the impacts of DSM on peak hour demand. From the review of other IRP reports, it appears that the challenges in identifying these DSM impacts at a greater level of granularity may be related to the differences in the regulatory regime in place for gas utilities, as well as a limited understanding of the gas end-use load profile.

[69] NW Natural. (2016). 2016 Integrated Resource Plan, p. 212, Ch. 6

8. Consultations with Other Gas Utilities

As part of the general review of the relationship between DSM and facilities planning, ICF conducted a consultation process as an extension to the literature review. ICF reached out to leading North American natural gas utilities identified as having experience working on integrated resource plans and conducted telephone interviews with key personnel from a cross section of utilities.

The aim of this exercise was to share information regarding the objectives of this study with these utilities and gain insights related to broad-based and geo-targeted DSM and facilities planning in their specific jurisdictions. The consultation process also aimed to include a discussion of the issues related to the impact of DSM programs on new subdivision and community planning. Interviews were conducted with the following utilities:

1. NW Natural Gas
2. FortisBC
3. PG&E
4. Questar

Each utility was interviewed by phone for approximately 1.5 hours. The next sections provide a discussion of the topics covered within these consultations, followed by key findings that were identified throughout the best industry practices review process.

8.1 History of IRP in other Jurisdictions

For this review of industry experiences, ICF first sought to obtain information on the history of integrated resource planning within each utility interviewed. From this, ICF gained an understanding of the main drivers for each utility's facilities planning processes and the regulatory framework impacts on them.

IRP planning for NW Natural began as a least-cost planning exercise. The utility noted that the IRP process first began in response to planning controversies in the 1970s and 1980s; the IRP process has since evolved in response to changing legislative orders. Older IRP reports were focused mostly on transmission and supply side resources and did not look beyond the city gates. A regulatory directive led to the formation of a larger IRP team, which now puts greater importance on facilities planning concerns.

FortisBC’s IRP process was prompted by the BC Utilities Commission (BCUC) with a facilities planning cycle that looks at meeting the system demand needs of the next 20 years. FortisBC's typical timeline for the release of IRP reports is every two years but there have been times when the BCUC specified a revised timeline to capture changes that may have happened in the market between the release of each IRP report. The utility noted that a lot of major facility investments had already been made. As such, with the exception of the interior Kelowna region, there aren’t many constraint areas at this time. A previous constraint identified on Vancouver Island was resolved with a large system storage tank project. Currently, potential future constraints are sufficiently far into the future that detailed assessments for resource options have not yet been considered. The typical timeline to start assessing resource options is four to five years to account for required approvals.

The PG&E IRP process began as a result of legislation passed in October 2013. The California Public Utilities Commission (CPUC) code section 769 required electric corporations to file distribution plan proposals by July 1, 2015, with the aim to "identify optimal locations for the deployment of distributed resources." The definition of distributed energy resources was specified to include "distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies." Utilities were also specifically required to conduct the evaluation based on reductions or increases in local generation capacity needs.

In addition to the CPUC code section 79 legislation, new legislation, known as the Clean Energy & Pollution Reduction Act (SB350), was passed on October 2015. Under SB350, California's renewable electricity procurement goal was increased from 33% by 2020 to 50% by 2030. This legislation requires publicly owned utilities with an average load greater than 700 GWh (from 2013-2016) to adopt IRP reports by January 1, 2019, and update them at least once every five years. The plans are required to evaluate how the utilities have chosen to align with the new greenhouse gas reduction targets, which includes targets for energy efficiency, gas use efficiency, and vehicle electrification.[70]

The Utah-based gas utility, Questar Gas, is regulated by the Utah Public Service Commission and the Public Commission of Wyoming. Within the States of Wyoming and Utah, Questar Gas has been involved in integrated resource planning since 1991, based on a requirement from its local utility commission. The utility was recently instructed by regulators to consider the potential impacts to peak demand from measures such as tankless water heaters. They are currently in the process of addressing these questions by developing a framework that would analyze both positive and negative peak impacts due to DSM.

8.2 Broad-Based DSM Experience in other Jurisdictions

NW Natural has had DSM programs in place since the late 1970s, early 1980s (e.g., weatherization programs) but these were much smaller offerings than are available today. In 2001, the Oregon Public Utilities Corporation (OPUC) helped form the non-profit Energy Trust of Oregon (ETO). In 2002, ETO, funded in part by a public purpose charge paid by Oregon customers of NW Natural and Cascade Natural Gas, began administering the company's DSM program offerings. Since then, the DSM savings projection has always been completed as a separate process, and is used later as an input to supply side resource planning by netting out expected DSM savings from the total load forecast.

NW Natural reported that the ETO is in the process of looking at tracking peak savings for DSM programs, although at this time they only track and provide information on annual savings. With this additional information from the ETO, the utility will look to assess the proportion of savings that are coincident with peak demand, allowing the utility to consider the value of DSM in avoided capacity resource acquisition. NW Natural indicated peak hourly impacts are typically only assessed for the industrial sector and they are currently exploring if any industrial customers in identified constraint areas are willing to sign interruptible agreements.

[70] Integrated Resource Plans (Publicly Owned Utilities). California Energy Commission (2017) http://www.energy.ca.gov/sb350/IRPs/

In the case of FortisBC, DSM spending in BC prior to 2009 was not a priority for the utility. Due to new provincial policy, however, there has been a move to increase DSM spending since 2009. In particular, the period of 2007-2010 was noted to have included aggressive government action to address climate change with policies such as the Greenhouse Gas (GHG) Reduction Targets Act, the Carbon Tax Act, and the Carbon Neutral Government regulation. There was also a Demand Side Measures regulation that was enacted in the fall of 2008, which set requirements for types of DSM programs within utility DSM portfolios, and guidelines for evaluating the cost-effectiveness of DSM programs. This was followed by the Clean Energy Act in 2010, which included specific integrated resource planning guidelines, including the implementation of DSM measures. These regulations were all spurred by the government's ongoing strategy to increase energy efficiency, reduce energy bills, and achieve provincial GHG emission targets.

Prior to 2009, FortisBC did not treat DSM as an investment option and DSM program offerings were focused on boiler programs as part of an operations and maintenance budget. Compared to its budget for its previous DMS programs (about $4 million), FortisBC's portfolio now has an available annual DSM spending budget of $32-35 million. Recently, the BC government provided direction to the utility to significantly increase incentive level spending, which would increase FortisBC's annual DSM budget to approximately $60 million.

FortisBC has a regulatory requirement to demonstrate that a system need cannot be met by DSM prior to making a facility investment. However, the utility noted that DSM as an alternative to facility investments has not been considered in detail as a resource option within the context of IRP planning due to a lack of evidence that DSM can reduce the peak demand. DSM has also not been assessed at a detailed level for integrated resource planning due to concerns regarding the timelines of projects. Previous proceedings in BC have expected one or two years' worth of delay in a facility investment project due to using DSM for infrastructure deferral and, as a result, it is too difficult to rely on estimated peak savings.

For PG&E, the CPUC IRP reports are currently directed only for the electric local distribution companies (LDCs) and the primary motive was stated as being driven by emission reduction targets for the state of California. The utility noted that they use CDM and DR programs in certain areas to defer the electric facilities planning process. According to the utility, DSM and DR ratepayer-funded programs have been used to contribute to load reduction during peak demand periods. Both DR and DSM programs are prioritized by the California Energy Action Plan as being a higher priority solution to meet increased demand before building more power plants.

Based on discussions with Questar, DSM experience in this jurisdiction is largely focused on the residential and small commercial markets, since the large commercial and industrial sectors requested to be excluded in 2007. The utility had a very successful weatherization program (attic insulation in particular) for retrofit residential customers; however, contractors have been making the move towards increased savings opportunities in the new construction sector since it provides them with a better market opportunity. As a result, DSM opportunities have been shifting focus away from the retrofit sector and towards new construction. Questar's current annual DSM spending is in the range of $24 million but their annual budget has been as high as $47 million. Questar cited lower natural gas prices as a major reason for the decrease in DSM activity, and that customers are less interested in reducing consumption since prices are low.

According to the published Utility DSM Program Data for 2016 and 2017, Questar's DSM budget for 2016 was approximately $26.7 million, with actual spending of $23.3 million for a total of nine program offerings. The majority of the DSM budget was spent on Questar's ThermWise® Builder program ($6.1 million), ThermWise® Appliance Program ($5.8 million), ThermWise® Weatherization program ($4.9 million), and the ThermWise ® Business program ($3.0 million).[71]

8.3 Industry Experience with Geo-Targeted DSM

ICF was unable to identify natural gas utilities in other jurisdictions that are using geo-targeted DSM programs to reduce facility investments in specific areas. Of the utilities interviewed, only NW Natural is planning a geo-targeted natural gas DSM pilot program. In the identification of their geo-targeted pilot study, the following types of DSM were identified by the utility:

- **Accelerated DSM*:*** Speeding up the timeline to acquire savings faster in a local area in cases where the measures/programs meet cost-effectiveness requirements statewide
- **Enhanced DSM*:*** Savings are not cost effective based on statewide avoided costs but are cost effective based upon location-specific avoided costs

At the time of the interview, NW Natural indicated that they were in the planning stages of the pilot, trying to identify which area was the best representative community to target. One of the major challenges it's facing is in determining the actual flows for the targeted area due to the number of areas that are served by multiple gate stations. Ongoing internal discussions include the installation of meters that would be able to provide greater insights into the hourly consumption. However, the residential meters that have been evaluated by the utility are unable to show a reading below one therm. Since residential consumption is typically below one therm per hour, the degree of resolution on the meter is insufficient to fully monitor the consumption levels behind the meter on an hourly basis. At this time, NW Natural is evaluating alternative metering options to determine whether investment into meters with a greater level of granularity is possible.

All of the utilities that ICF spoke with said that DSM program timing is one of the most important factors to consider in integrated resource planning. Most of the utilities agreed that a five-year lead time would be required to incorporate DSM as an effective strategy to defer facility investments. This would allow sufficient time to obtain necessary regulatory approvals, identify a target area, set up baseline and post-project measurements, and implement the DSM program. Some utilities noted that, given how far in advance the planning process would need to begin, it is difficult to forecast changes in peak demand with a high degree of accuracy that far in the future.

A couple of utilities noted that geo-targeted DSM programs raise a greater issue against the principal of universality to offering the same programs across the entire service territory. For NW Natural, the aim is to complete the geo-targeted pilot using existing DSM programs that have been screened using statewide annual costs and benefits, but without specific consideration of the cost-effectiveness of the peak day impacts on facilities requirements in order to avoid

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[71] Utility DSM Program Data: 2016 and 2017, Southwest Energy Efficiency Project (2016). http://www.swenergy.org/Data/Sites/1/media/events/regional-workshops/2016/2016-17-Utility-DSM-Program-Data.pdf

discrimination by customer location. However, the utility is discussing funding mechanism issues that would arise for future geo-targeted DSM initiatives. A potential justification for the unequal distribution of these programs is that all customers are able to benefit from the lower rates, even if they may not be able to participate directly in the programs. This is an issue that all of the utilities agreed requires further consideration.

FortisBC noted that they have not yet explored geo-targeted DSM options since their main priority has been focused on assessing energy savings in gigajoules rather than peak-based reductions. Currently, FortisBC is working on the development of load profiles to translate consumption savings into an annual peak. This approach is designed to leverage the knowledge around electric load profiles in terms of the major thermal end-uses, and then use SCADA systems to calibrate the end-use demand.

Questar Gas indicated that they have yet to explore geo-targeted DSM options. The utility noted that increasing growth in the state of Utah is the biggest challenge in identifying a target area. Nonetheless, the utility has taken steps to obtain hourly residential customer usage data with an ongoing advanced metering deployment project. At the time of consultation, the utility had approximately 10,000 meters installed for commercial and industrial sector customers.

PG&E staff also noted that it currently has three location-based pilot programs that are being developed by the California commission's working groups but that these programs are focused on the electricity sector and are in the early development stages.

8.4 DSM Program Cost-Effectiveness Screening

Most utilities include the estimated costs of peak day gas supply, in addition to the annual energy savings when assessing the value of DSM. The utilities ICF spoke with commonly use the TRC test, but the utility cost test (UCT/PAC) was mentioned as being better suited to capture costs incurred by the program administrator.

With regards to the treatment of avoided costs, NW Natural reported that it includes peak impacts in the avoided costs, and has plans to update the avoided costs for the 2018 IRP report to capture these costs. Currently, NW Natural calculates a 20-year forecast of avoided costs. In its upcoming 2018 IRP report, NW Natural Gas plans to have avoided costs be an output of the IRP optimization process, rather than an input.

Cost-effectiveness testing for DSM programs in NW Natural's service territory is completed by the ETO. Utility staff noted that Oregon requires a TRC calculation, whereas Washington allows for a different cost test, such as the UCT, to be employed. The Washington commission prefers the use of a balanced TRC test, which is designed to capture total benefits as they happen.

PG&E noted that the most important cost-effectiveness calculations are typically the TRC and PAC tests. In the utility's IRP report, it specifically outlined an approach to replace system-level costs and benefits with location-specific benefits and costs to select optimal locations for distributed energy resources. The cost-benefit categories identified included distribution, transmission, generation, and other societal costs/benefits. The location-specific cost-benefit analysis is expected to generate a list of optimal locations in the form of "heat maps" showing areas with increased value associated with facility investment requirements. In addition, a

Location Net Benefit Analysis Tool has been developed to calculate locational avoided costs for utility T&D projects, and avoided cost benefits for a load reduction shape.

8.5 Facilities Planning

NW Natural Gas noted that its commission has requested major facility investments to be included in the IRP process. However, the commission guidance on this issue is limited. The utility noted that the facilities planning process is based on the assessment of a variety of demand forecast scenarios developed through system flow modeling approaches. The utility noted that historical gas use is used to develop a load forecast before community expansion projects are identified, and that DSM impacts have historically been netted out from the load forecast process, rather than an integrated process. The utility is working on methods to better integrate DSM impacts into its 2018 IRP report.

When considering the metrics that drive the facilities planning process in FortisBC, it was noted that, for integrated resource planning purposes, there is a great dependency on where in the system the infrastructure is needed. For example, investments in areas with a lot of storage capacity would be driven by peak day needs; investments in areas with a shortage of storage capacity would be driven by peak hour requirements.

In terms of AMI capabilities, FortisBC found that, while natural gas metering has always been a point of consideration it has never made sense from a traditional business perspective. The utility looked at the possibility of metering a subset of the customer base and tracking natural gas usage over time, but this was ultimately seen as increasing the incremental equipment and program costs to interested customers.

Questar Gas found that it is difficult to target infrastructure deferral simply due to the increased level of demand growth in its jurisdiction. The utility currently attempts to size infrastructure to meet future build-out of developments so that costly expenditures in the future can be avoided. The utility noted that its infrastructure budget was approximately $209 million in 2017, of which $25-30 million was spent on new mains and $15 million was spent on high-pressure expansion. The utility identified replacement projects as higher priority investments compared to new customer growth related investments. The utility also noted that it determines facility size requirements based on available historical peak occurrence data. DSM is captured in these estimates, to the extent that DSM impacts are captured within the historical data. DSM impacts were found to cause a downward trend in total annual consumption. However, the usage per heating degree day (HDD) remained constant during the peak day, which the utility found to be an indication that DSM had minimal impact during peak day events.

8.6 Forecasting for Peak Day & Peak Hour Impacts

ICF was unable to identify any natural gas utilities outside of Ontario that explicitly consider the impact of DSM programs on peak hour or peak day demand for facilities planning purposes. The DSM impacts are most commonly assessed as annual demand reductions. None of the jurisdictions had tracked peak day or peak hour savings from DSM programs in the past, although some are now taking steps to begin tracking those impacts. For example, NW Natural is working with the Energy Trust of Oregon to track peak hour savings for the development of its geo-targeted DSM program.

Gas utilities also expressed concerns about the reliability of DSM as a facility investment alternative due to the lack of information on the impacts of certain measures on peak hourly demand. That includes measures such as tankless water heaters and adaptive thermostats, which potentially cause increases in natural gas consumption during peak periods (15-minute to one-hour increments). Modulating equipment, such as controls and automation measures (including VFDs), was also noted as having potential to change the prediction of peak size and the amplitude of peak occurrence. One utility noted that natural gas consumption within its service territory is becoming peakier over time due to changes in its customer mix, and potentially due to the implementation of more efficient technologies.

8.7 New Subdivision and Community Planning

No utility was able to provide significant insight into the use of DSM to impact new subdivision and community planning. ICF was interested in finding out whether utilities are involved early enough in the subdivision planning stages to make an influence on factoring DSM into the facilities planning process. According to NW Natural Gas, a lot of the growth occurring in new subdivision and community planning has been reactive, with the builder/developers often getting in touch with the utility first. Some organizations such as NEA (Northwest Energy Alliance) have worked to target new construction areas to install measures such as high-efficiency furnaces, but these efforts are still relatively new. NW Natural Gas also indicated that new community planning is more difficult due to changing timelines for new community expansion projects and robust land use planning guidelines set by the state of Oregon. Some of the challenges are due to land use planning guidelines, which require two to three years for a leave to construct. This would mean that the needs of future communities would need to be forecasted at least five years in advance. The utility noted that using DSM to reduce investment for new community development may reduce future flexibility if community development plans change.

In terms of load forecast planning for new customers, NW Natural Gas indicated that historical flows are typically used when looking at the trend in projecting flow, and that DSM is typically included in the historical flows. The utility also employs an approach of adding load to existing customers within load forecast projections to account for new customer growth, rather than forecasting new areas where the utility thinks the load will occur. Questar Gas indicated that new community planning is a low priority, with greater emphasis put on reinforcement and existing community investments.

8.8 Key Findings in Other Jurisdictions

Throughout the consultation process, ICF attempted to evaluate the utilities' experiences with DSM and facilities planning. Overall, ICF found that the conclusions listed below were consistent with the experiences of the North American gas utilities interviewed.

- **The reliability of peak period reductions due to DSM investments is unknown:** Gas utilities have more extensive experience with the use of interruptible tariffs to manage peak hour and peak day demand for large commercial and industrial customers that do not require firm service. Certain gas utilities, including FortisBC, Vermont Gas, and Gaz Metro have used or evaluated alternative sources of supply (e.g., storage, LNG, virtual pipelines) to reduce the need for new distribution system pipeline capacity. Utility planning staff have stated that provincial/state public commission boards require a leave to construct application to run a targeted DSM program, and that this requires having very early knowledge of the risks in spending the money in place of infrastructure investment. For most utilities there is no guarantee for rate recovery if the savings do not materialize.

- **Accurate metered data on peak period demand is unavailable:** Most utilities are able to identify peak hourly data only at a system gate station level, and cited that further granularity is limited. Only a few utilities were considering additional metering to be able to measure peak hourly impacts. NW Natural stated that accurate metering is desired for its planned geo-targeted DSM pilot to measure the baseline case and the impacts of the program. Although it is not assessing geo-targeted options, Questar has invested in AMI, which would give it the capability to analyze peak hour data.
- **Changing lead times for projects:** Utilities estimated a minimum lead time of five years to incorporate DSM, and that this timeline poses a concern where demand in some jurisdictions is growing quickly. For example, a utility can attempt to use DSM to reduce facility investments but would run into issues if a large customer was added to the service area, resulting in the need for additional capacity. Some state/provincial commissions may provide utilities with the flexibility to explore multiple options to meet distribution facilities planning needs, but there would need to be a reasonable cut-off time after which only one option could be further pursued.
- **Principle of universality:** By not offering the same programs across the entire service territory, the principle of allowing access to DSM programs to all consumers across the service territory poses an equity concern. Other utilities are still exploring the correct funding mechanism to use in this scenario. Some utilities noted concerns about the possibility of unequal treatment in different income classes because the largest peak period savings will accrue to larger homes and new construction, and it may not be economical to provide the same benefits to lower income residences in smaller buildings.

III. Infrastructure and DSM Planning Process

This section of the report reviews the relationships between the Gas Utilities' facilities planning and DSM planning processes, including some of the key policy issues that may affect how DSM is considered in facilities planning. The review includes:

- An overview of the facilities planning process. The review of the facilities planning process focuses on distribution and transmission system facilities downstream of the utility city gate. The facilities planning review includes an assessment of the relationship between the forecasts of natural gas demand and the need for new facilities, as well as the issues related to hourly demand and hourly system flows and the implications for facilities planning. The assessment also includes a review of the facilities planning timeline, which sets the basic milestones that a DSM program designed to reduce infrastructure investment would be required to meet.
- An overview of the DSM planning process. The review of the DSM planning process focuses on the objectives of the existing DSM planning process, as well as the DSM planning, implementation, and evaluation timeline.
- An assessment of the major differences between the facilities planning and DSM planning processes, highlighting differences in schedule, risk, and other factors that impact how the current planning processes are conducted in these two utility planning areas.
- A discussion of the steps that would be needed to more fully integrate the facilities planning and DSM planning processes.
- A review of key policy issues identifying critical differences in the policies impacting infrastructure planning and DSM planning that would need to be addressed to integrate DSM planning into the infrastructure planning process.

1. Facilities Planning Principles

The primary goal of the facilities planning process is to ensure that the utility infrastructure is of sufficient size to provide reliable natural gas service at the design condition on an ongoing basis and that this is being accomplished with reasonable costs.

Facility investments are required for a variety of reasons, including:

- Maintain system integrity, including the relocation and replacement of existing facilities that no longer meet current class location, safety, or operational standards as determined by other engineering criteria
- Serve growth in peak hourly and peak daily demand on existing systems resulting from new customers, growth in existing customer requirements, and changes in customer usage patterns
- Serve new communities, new subdivisions and main extensions to unserved locations
- Replace existing infrastructure as necessary to meet utility safety standards and regulations.

Investments generally are predicated on the need to reliably serve system demands at the required customer delivery pressure during design day demand conditions. Gas utilities look at historical gas use and gas use trends as the base to forecast future consumption. Planners take into account customer growth, economic development changes in gas use resulting from historical implementation of DSM measures, as well as other factors such as improved building code standards, and higher energy-efficiency standards for natural gas equipment. However, facility investment plans typically do not factor in DSM program effects on future peak day or peak hour demand.

Facility investment plans are based on a long-term growth forecast intended to identify potential incremental facility requirements and to develop the required facilities prior to the need for new facilities. The facilities planning process is designed to allow utilities to proceed with planned investments, or accelerate/defer/revise planned investments depending on how closely customer attachment rates and load growth match the forecast. The basic facilities planning process is summarized in the exhibit below. Key aspects of this process are discussed in more detail in the text that follows.

Exhibit 3: Overview of the Facilities Planning Process

Facility Investment Drivers

- Facility investments are designed to meet one or both of the following requirements:
  - Maintain system integrity (i.e., meet safety and operational standards)
  - Serve growth on a peak hour and peak day

Growth Drivers - Meeting Peak Day and Hour on Transmission and Distibution Systems

- New customer attachments
- Increase in existing customers demand
- Changes in customer usage patterns
- Serving new communities and subdivisions

Utilities Use Multi-Year Growth Forecasts

- Estimated peak hour consumption/demand for distribution systems
- Estimated DSM effects on consumption included based on historical usage
- Estimated peak hour and day demand for transmission systems
- Hourly load profile that varies the demand over the day
- Location of Growth

1.1 Consequences of Insufficient Facilities

Gas distribution pipelines are network systems characterized by city gate stations receiving gas from large diameter high-pressure pipes (transmission), delivering the gas into a network of branching lower pressure pipes (mains), which in turn branch into smaller diameter mains, and eventually into the smallest diameter service lines that feed individual customers' buildings. Gas flows through the distribution network from high pressure to low pressure as dictated by customer usage. The utility regulates pressure across its pipeline system with a system of strategically placed regulator stations.

The pipeline system must be designed to ensure that the pressures in the mains are adequate to supply all of the gas being used on the service lines on the coldest day. The job of the distribution system is to serve the highest hourly gas usage based on the daily transmission pipeline flow.

Gas utilities' distribution and transmission systems are designed to meet the highest expected firm gas demand on a "design day". The design day for Union Gas is based on the coldest historic winter conditions; for Enbridge, the design day is based upon a one in five recurrence interval (based on a lognormal distribution) for peak and multi-peak degree days. In practice, the two approaches lead to relatively similar design day temperature criteria.[72] The design day facility infrastructure plan is based on:

- Facilities designed to meet design day demand loads.
- Service offerings designed to reduce load during peak demand periods. Gas utilities offer interruptible services to customers at lower rates than firm service. When daily demand forecasts indicate that total demand, including interruptible demand may exceed firm service requirements, utilities will interrupt these customers to redirect gas to the firm customers.
- Plans to curtail certain firm demand in extreme circumstances. In order to maintain system integrity, a utility may curtail deliveries to some firm customers who are better able to tolerate loss of gas than smaller residential and commercial customers.

If demand on any portion of the system exceeds the ability of the system to supply natural gas demand, the natural gas system pressure may fall below what is needed to deliver gas on part of the distribution system and the system may experience unplanned and uncontrolled outages (e.g., pilot lights fail). At this point, the biggest issue is the overall safety of the system. Utilities respond by identifying and isolating the affected area, shutting off the flow of gas to the customers on the affected part of the system.

Safely relighting a section of the distribution system requires a series of time consuming steps. Any event resulting in a loss of operational gas system pressure on any part of the system would require:

- Turning off service valves at every customer meter in the affected area

[72] For a description of the differences and similarities in the utility design day planning criteria, see EB-2015-0238 Distributor Gas Supply Planning Consultation Gas Supply Planning Comparison March 22, 2016. https://www.oeb.ca/oeb/_Documents/EB-2015-0238/Gas_Supply_Planning_Comparison_Document_20160316.pdf.

- Correcting the underlying issue that created the loss of system pressure
- Reintroducing gas into the affected mains and services
- Purging the affected mains and services to ensure that the pipes are filled with 100% natural gas
- Unlocking customer meters and relighting customer appliance pilot lights on a customer by customer basis

A large scale relight could take weeks rather than days or hours to resolve. Hence, insufficient infrastructure to meet design day demand could lead to a system shut down during the coldest part of the winter, leaving residential and commercial customers without heat during dangerously cold weather for an extended period of time. Utilities would likely need to enact emergency plans and would need hundreds of personnel to relight customers. Community emergency plans might also need to be activated to move people into warming centres.

This is fundamentally different from the planning principles used by electric utilities. Electric utilities experience service disruptions with greater frequency than gas utilities. Electricity delivery can be disrupted by storms that result in downed power lines, by severe weather conditions that stress the transmission grid or generation capacity, or by system outages or blackouts that can cascade across broad geographic areas. These effects can be severe and widespread and electric markets have generation reserve requirements to avoid or minimize outages. As such, the electricity system is designed with the expectation of individual facility failures. However, the consequences of a service outage are also much different. An electric system outage is much simpler to restore than a natural 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 is a much more complicated and time consuming process.

1.2 Forecast of Peak Day and Peak Hour Demand

The forecast of peak period demand is a critical component of the Gas Utilities' facilities planning process. The natural gas industry plans on both a daily and an hourly basis. Upstream of the city gate, gas supply contracting is typically expressed in terms of daily quantities. Gas supply and gas transportation contracts are denominated in GJ per day. Gas supply contracts will state that the supplier is obligated to supply a given amount of gas each day. Similarly, gas utilities reserve capacity on long haul transmission pipelines in terms of maximum daily quantities (MDQ) for delivery to the city gates. In this study, the amount of contracted capacity is referred to as contract demand (CD). Unless specific arrangements are made, transmission pipelines generally require that receipts from suppliers and deliveries to buyers are spread relatively equally over the course of the day on a ratable basis. Hourly receipts and deliveries typically can be no higher than one-twentieth of the CD. However, pipelines also offer transportation services that allow higher rates of receipts and deliveries. Transmission pipelines also allow intra-day adjustments in gas flows. Nevertheless, the industry operates over a "gas day" (a 24-hour period beginning at 9 a.m. Central time).

Downstream of the city gate, utilities design distribution system facilities to meet peak period demand. The peak period depends on the type of facility being considered. Most distribution system assets are planned based on peak hour requirements. Larger mainline transmission assets often can be designed around longer peak periods ranging from 4 to 24 hours, depending on the size, location and length of the transmission asset. The two utilities differ somewhat in their planning processes due to the differences in their service territories:

- Enbridge has limited long haul transmission facilities, and the Enbridge facilities planning process is focused primarily on peak hour demand.
- In addition to the Dawn Parkway system, which was not addressed in this study, Union has a mix of relatively large transmission facilities and distribution facilities, and utilizes peak hourly demand forecasts when planning many of their distribution facilities, and peak period/peak day demand forecasts when planning transmission facilities.

Since customer usage determines the rate of flow, the facilities planning process for a distribution pipeline system requires the estimation of peak hour and peak day consumption for each year in the planning forecast, as well as an hourly load profile. There are four main customer types considered in this planning process:

1. **Firm Contract Customers**: Large volume commercial and industrial customers that have contracts obligating the utility to provide the customers with required hourly and daily firm delivery service. These customers use the distribution system to provide delivery service to their facilities. The firm contract customers have hourly and daily gas measurements, which increase the accuracy of the estimated customer peak usage.

2. **Interruptible Contract Customers**: Large volume commercial and industrial customers that have some or all of their gas requirements contracted as interruptible service. These customers use the distribution system to provide delivery service to their facilities. Under these service agreements, customers agree to have their gas supply interrupted when the utility needs pipeline capacity to serve the firm service customers. These customers have alternative fuel capability that allows them to switch when there is insufficient pipeline capacity to serve their facility. Interruptible service tolls are lower than firm service tolls and utilities usually require interruptible service customers to demonstrate their ability to fuel switch. There may be some limit to the number of hours or days service may be interrupted, but generally speaking, interruption is at the distribution company’s option. Normally, these customers would be interrupted under design day conditions.

3. **General Service Firm Customers**: Includes residential firm service customers and small commercial and industrial general service firm customers. Existing general service customers are assumed to behave in a manner consistent with their recent 24-month weather adjusted consumption behaviour. Each customer's monthly billing history is examined and statistical relationships are made to determine monthly consumption as a function of monthly HDD, the number of degrees that an average temperature is below 18ºC[73]. The utilities use this process to estimate the peak hour demand for existing customers at the design degree day.

[73] It should be noted that the Gas Utilities each take a slightly different approach to heating degree days; Enbridge calculates HDDs based on dry bulb temperature, while Union accounts for wind speed and cloud cover in their calculation of HDDs.

Customer gas usage varies throughout the day, with the highest co-incidence of furnace, hot water, and other gas uses occurring in the morning hours between 7 a.m. and 9 a.m. (the time that most people start their day). There is a secondary peak of gas use in the late afternoon and early evening; however, it is not as large as the morning due to the varied times when people arrive home.

4. **Unbundled Customers:** The utilities also consider contracted Maximum Daily Volumes (MDV) for unbundled customers in the facilities planning process. Unbundled customers contribute to peak period demand, so they must be considered in the facilities planning process, but are responsible for their own gas supply and balancing requirements. As such, they do not contribute to upstream gas supply planning requirements.

The importance of the peak hour gas consumption to a gas utility is how that translates to gas pressures and flows across the system, and, in turn, the adequacy of the various supply inputs and facilities (transmission and distribution mains, regulator stations, customer stations, and service lines) needed to meet consumer demand. To meet peak day load growth, the utility must design its facilities to meet an expected peak hour flow on the design day. If the system is not capable of meeting this demand, pressures will drop and the system integrity could be compromised. The peak hour consumption is what is used to assess the system's operability and health.

Estimating peak hour consumption and forecasting future peak hour consumption can be straightforward for some large customers due to hourly flow requirements that the meters record. However, the vast majority of customers have meters that are read only monthly. Monthly readings are typically converted to daily estimates using weather data and linear regression models and this helps a utility plan its daily gas purchases and pipeline transportation and storage contract demand.

Where metered customer data on hourly demand is not available, the Gas Utilities use gate station data as a proxy for hourly demand. However, one of the limitations of using gate station flows is that they do not necessarily reflect the hourly consumption of gas across the distribution system. Depending on how much gas end users consume in any hour, pressures in the mains may increase as more gas flows into the system than is being used (i.e., line packing is occurring) or in the opposite, more gas is drawn off than is entering the system causing pressures to drop.

In the absence of reliable hourly end-use data, gas utilities often use a general factor of 1.2 to convert average hourly flow on the design day to a peak hour flow for design day conditions. Peak hour flow is estimated to be 1.2 times the average hourly flow over the 24 hour period. Recent research by Union Gas suggests that this multiplier works reasonably well.[74] In 2014, ICF prepared a report for the Eastern Interconnection States' Planning Council (EISPC)[75] that used consumption data by building type and sector to estimate the hourly swing in gas use on a peak day in four regions of the Eastern Interconnection. The most relevant of these regions for

[74] Edwardson, Steve, The Next Dimension of Load Profiles, PSIG 1617, Pipeline Simulation Interest Group, 2015

[75] ICF, Study of Long Term Electric and Gas Infrastructure Requirements in the Easter Interconnection (2014) prepared for EISPC. See Section 3.2.7 for the hourly load analysis (report available from ICF)

Ontario are New England and Northern Illinois (Midwest). The analysis showed that on a peak day in New England the peak hour swing over average peak day consumption would be around 8-9% and in Northern Illinois, 11-13%. The results from this study generally support the use of the 1.2 multiplier to go from average hour flows to peak hour flows on a design day..[76]

In addition to estimating peak day and peak hour demand for existing customers, the facilities planning process also factors in new customers that are expected to be connected during the forecast period and to the existing geographic footprint of the pipeline system. These customers are modeled based on a typical average for new customers within each “customer class” (for example, a large single-family detached house). The count of new customers within each planning zone is based on historical connection rates in each zone, plus what is known about specific new large buildings and housing developments.

The forecasted growth in new customers represents an area of significant uncertainty in the demand forecasts, as the rate of growth and location of growth in the number of customers can change quickly based on changes in economic conditions, the locations of new communities, and changes in commercial and industrial consumer plans and outlooks.

The use per customer data that is used to project consumption for existing and new customers takes into account recent historical trends including the impact of DSM programs, but does not explicitly factor in DSM program effects on future peak day or peak hour consumption.

1.3 Sizing of Incremental Facility Investments

Incremental facility investments include upgrades to existing facilities and the expansion of distribution services to new or underserved communities or residential subdivisions. Facility upgrades to meet safety obligations, such as replacing old pipe, or to improve operational efficiency, such as installing new regulator stations, replacing old stations or new supervisory control and data systems (SCADA), require some assessment of system-wide growth and peak day requirements. However, upgrades are typically driven more by the condition of existing facilities, rather than the rate of growth in new communities.

Expansion of the distribution system into new communities and residential subdivisions and to add new customers involves some assessment of both the size of the new demand (peak day and peak hour) for sizing main and service lines, as well as for upgrading any upstream city gate and regulator stations and mains feeding into the new facilities.

One of the challenges with developing new facility investments is determining the future demand and the location of the demand. Economic development, location of new housing developments, and customer types are all difficult to forecast with certainty, creating a range in future demand growth that must be planned for.

Pipelines have significant economies of scale since the volume increases with the square of the pipe radius. The cost of the incremental unit of capacity also declines as the size of the project increases due to efficiencies in planning, right-of-way and easement availability, mobilization

[76] Ibid, p. 87-88. Most of the hourly increase would be in the residential/commercial load and in the power generation consumption. Hourly increases over average peak day consumption would tend to occur in the mornings and in the early evenings.

costs, and labour and materials costs. Therefore, the utility, and its customers, have a significant economic incentive to plan based on upside uncertainty in the forecast demand rather than downside uncertainty.

New facility investments also result in significant disruptions to streets and communities that the projects pass through, leading to a strong incentive to be "one and done" with any project or group of projects. As a result, the timing of facility investments can be influenced by factors outside the control of the Gas Utilities. In order to be "one and done," investments can be accelerated or delayed to correspond with municipal development schedules related to facility investments, such as bridge repair and replacement, road construction, or water and sewer repairs and extensions.

Replacement of old pipe often proceeds on a schedule related to the age of pipe to be replaced, despite the fact that such replacements will also enhance the capacity of the distribution system.

The desire to take advantage of other facility investments, and the need to minimize community disruptions can lead to upsizing or accelerating facility investments for projects where future expansions would be particularly disruptive or expensive, and may make deferral of some gas facility investments impractical, despite the potential for geo-targeted DSM to reduce peak period demand.

1.4 Impact of Reductions in Forecast Demand Growth

In many gas distribution systems, especially older ones, loads in parts of the system may decline. This happens, for example, when parts of a city are re-developed, or where gentrification provides building envelope enhancements and new, more efficient appliances. More broadly, the introduction of newer end-use technologies or warmer climates may reduce demand or slow demand growth.

Reductions in forecast demand growth can impact facility investments in several ways. Generally, a reduction in peak hour demand will result in decreased or delayed facility investment on the affected portion of the system, although the decline in demand may not impact the need for maintenance or replacement of older system parts. The change in infrastructure requirements can result in:

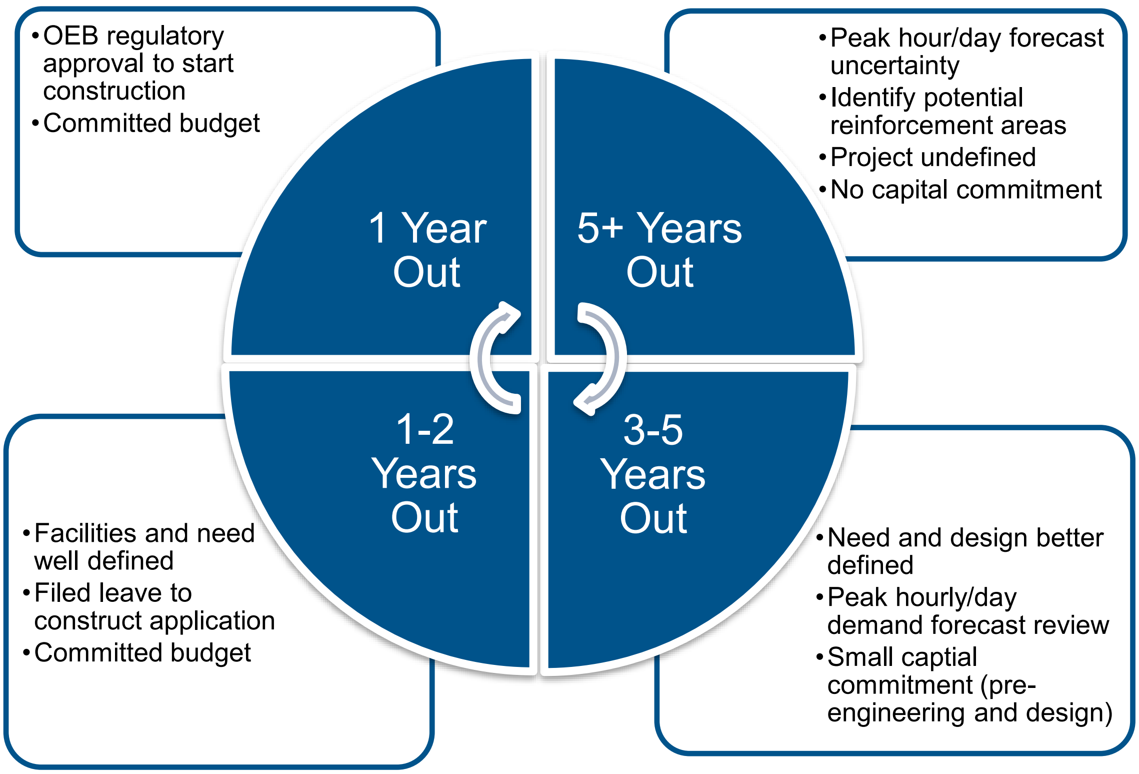
- Delay or cancellation of enhancement projects
- Decreased diameter of the pipeline or reduced pipeline looping (i.e., the new project may be sized smaller than originally planned)

For many projects, the amount of capacity added is determined in part by the length of the pipeline project. Growth in a specific location can often be served by a project that eliminates constraints between a supply point and the region with expected demand growth. This rarely requires the construction of an additional pipeline from the supply point all the way to the location of the demand growth. Instead, the incremental capacity can be provided by adding sections of pipe on the most constrained section of the system. Hence, reducing hourly demand growth could also reduce the need for specific sections of new pipe.

1.5 The Facility Investment Planning Schedule

Utilities' capital planning budgets are based on forecasts of system demand, new subdivision and community connections (i.e., new loads), and ongoing maintenance of existing facilities. The capital planning process typically looks out five years and gradually commits to expenditures over time in order to ensure that new infrastructure is in place when necessary to meet demand. Exhibit 4 summarizes the facilities planning process.

Exhibit 4: Facilities Planning Timeline



1.5.1 Long Term Planning - More than Five Years Out

A typical facility investment plan begins by identifying the expected need for additional capacity. This generally occurs by about five years prior to when the capacity is likely to be required. At this point in the process, a forecast of natural gas demand growth for different sections of the distribution system has been prepared, and comparisons of expected demand to the currently planned system capacity indicate a potential shortage of capacity.

The long term demand forecast will represent the best available data on demand, however, the utilities will account for the underlying uncertainty in the demand forecasts, including the potential for both faster than expected system growth and slower than expected system growth.

Facility investments needed for purposes other than demand growth will also be identified starting during this period. These projects, which would include replacement of aging pipe for example, will have a separate schedule not necessarily tied to demand forecasts.

No capital would be committed at this point. However, the utility would start focusing on potential areas where system reinforcement may be needed, and will start looking at how the need for new capacity might be met.

1.5.2 Mid-Term Planning - Three to Five Years Out

During the period from three to five years out, the forecasts of demand growth are refined, and projects with the potential to meet the requirements are identified. The demand forecasts are updated to reflect the best available knowledge concerning future demand growth, relative to the expected capacity of the system, in order to determine both the timeline and magnitude of the incremental capacity needed to meet the incremental demand growth. At this point, the timing for the need for the projects is determined, capital budgets for the potential projects are developed, and small initial investments are made for engineering, environmental assessments, and design. By the end of this planning phase (three years out), planning for larger, more complicated projects will need to be relatively complete and comprehensive, while smaller, less complicated projects may be identified well into the next phase.

Planning for facilities replacement investments required for reasons other than demand growth, including replacement of aging pipes, will also proceed during this period, and replacements of major sections of the system will need to be completed.

1.5.3 Near-Term Planning - One to Three Years Out

During this period, the projects are fully specified, the detailed capital budget is refined, and management will review updated demand forecasts, in order to make a final investment decision. Final changes in the outlook for demand growth are taken into consideration at this time in order to finalize the schedule for the project.

The utility will submit requests for leave to construct, supported by analysis and cost information, to its regulator. Significant costs will be incurred by the gas utility to finalize the engineering design, commence land acquisition, initiate the leave to construct process, and complete the required permitting and regulatory processes.

1.5.4 Construction

The facility typically is built in the final year before it becomes necessary to meet demand and after the leave to construct is approved by the regulator.

2. Overview of DSM Planning Process

The current DSM planning process is largely separate from the facilities planning process, and reflects the guidance of the OEB DSM Framework (the most recent was established by the OEB in December 2014). The OEB DSM framework is designed to reduce natural gas consumption throughout Ontario, with the ultimate goal of ensuring that savings are achieved efficiently, with customers receiving "the greatest and most meaningful opportunities to lower their bill by reducing consumption."[77] In its 2015-2020 DSM Framework report, the OEB set three goals for ratepayer funded DSM:

1. Assist consumers in managing their energy bills through reduction of natural gas consumption

[77] Ontario Energy Board. EB-214-0134 Report of the Board Demand Side Management Framework for Natural Gas Distributors (2015-2020). December 22, 2014, p. 1

2. Promote energy conservation and energy efficiency to create a culture of conservation
3. Avoid costs related to future natural gas infrastructure investment, including improving the load factor of natural gas systems. Gas utilities are expected to consider opportunities for DSM to help reduce infrastructure costs.

2.1 Key Features of the 2015-2020 DSM Framework

The DSM Framework:

- Sets annual energy targets based on annual lifetime cubic meter savings, which are aggregated to form the 2020 cumulative lifetime energy savings target. These targets are adjusted annually based on the target adjustment mechanism. There are no peak demand cubic meter reduction targets, only annual consumption reduction targets.
- Establishes annual DSM program budgets. The Demand Side Management Variance Account (DSMVA) tracks the variance between budgeted expenditures by rate class and actual spending by rate class for annual disposition by the OEB, including account carrying charges.
- Allows the Gas Utilities to spend up to 15% over the approved annual DSM budget, if prudently incurred, to pursue aggressive DSM beyond the 100% program target(s).
- Uses the avoided costs for calculating the cost-effectiveness of programs. Program screening is based on the TRC test; the PAC test has been added as a secondary screen.
- Includes non-energy benefits through the addition of a 15% adder in the calculation of the TRC test (becoming a TRC-Plus test), aligning the natural gas TRC calculation with that of the Ontario Electric CDM framework, and thereby aligning natural gas DSM with the government directive to the IESO on the inclusion of the adder.

2.2 DSM Budgets and Programs

The approved DSM plans of the Gas Utilities contain an approved budget for each year of the framework (2015-2020) as well as an approved total DSM budget. The approved budgets are consistent with the OEB's established target of a $2.00/month approximate rate impact for a typical residential customer. Exhibit 5 provides an approximate share of the budget for the 2015-2020 framework by customer type.

Exhibit 5: DSM Budget by Type of Program

2016-2020 Budget		Residential Budget excl. Low Income	Residential Low Income Budget only	C&I Budget excl. Low Income	C&I Low Income Budget Only	Large Volume	TOTAL
EGD	Percentage	41%	12%	37%	9%	-	100%
UG	Percentage	26%	19%	41%	7%	7%	100%

Most program offerings are focused on incentives to offset a portion of the costs associated with high-efficiency space heating and water heating technologies. The 2015-2020 plan focuses on continuing successful programs, while implementing new programs with a holistic approach, such as direct install programs, energy audits, monitoring and tracking, and programs that target customer groups with entry barriers (e.g., small business customers in commercial offerings and low-income customers). The types of programs offered are shown in Exhibit 6.

Exhibit 6: DSM Program Types

C/I & Industrial Programs	Residential Programs
• **Space Heating:** Air Curtains, Condensing Boilers, Condensing MUA Units, Condensing Unit Heaters, DCV system, ERV and HRV, Condensing Furnaces, Infrared Heaters • **Water Heating:** CEE Tier 2 Washers, Condensing Boilers, Condensing Gas Water Heaters, Ozone Laundry • **Food Service:** DCV Kitchen, ENERGY STAR ® appliances (fryers, steam cookers, dishwashers), High-Efficiency Under-Fired Broiler • Engineering Feasibility Studies • Standard Prescriptive • Direct Install Pilot • Process Optimization funding, Run*it*Right / Runsmart Building Optimization • Strategic Energy Management Offering	• Home Reno Rebate/ Home Energy Conservation Program • Adaptive Thermostats • Home Weatherization • SF Furnace End-of-Life Upgrade • Aboriginal Offering

Each Gas Utility's approved DSM plan contains resource acquisition, market transformation, and low-income programs. There are specific resource acquisition programs for the residential, commercial and industrial sectors, and specific market transformation programs for the residential and for commercial sectors. Resource acquisition programs comprise the greatest share of the budget and targets of the respective DSM plans. In addition, each Gas Utility has an approved budget allocation to fund collaboration, innovation, and pilot programs.

The DSM programs include standardized or prescriptive energy-saving measures as well as customized offerings tailored to a customer's individual circumstances. Recently, the majority of the Gas Utilities' DSM program's volumetric savings have resulted from the custom offerings for commercial and industrial customers. Prescriptive savings are based on engineering estimates developed and reviewed by the Gas Utilities and approved by the OEB. Savings for custom offerings are based on metered data, engineering calculations, and savings verification audits of a sample of program participants.

2.3 DSM Targets

The DSM Framework sets annual cumulative lifetime energy targets, which are then aggregated to total cumulative lifetime savings (CCM, cumulative cubic meters) to be achieved by the end of 2020. Enbridge and Union's yearly target is calculated based on a formula that takes into account the previous year's achievements. The DSM Framework also uses other metrics in setting annual performance targets in addition to CCM. Significantly, there are no peak hour or peak day demand reduction targets.

2.4 Program Screening

In the 2015-2020 framework, the OEB adopted an enhanced TRC, the TRC-Plus test, to be used by the Gas Utilities to screen potential DSM programs.[78] The TRC-Plus test includes a 15% non-energy benefit adder to the benefit side of the TRC calculation. The 0.7 TRC (now

[78] All potential programs, except for market transformation programs, are screened by the TRC-Plus test.

TRC-Plus) remains the low-income program threshold screen. For this framework, the OEB added a secondary test, the PAC test, to better inform the selection of programs.

Natural gas DSM plans account for potential savings in system-wide facilities created by DSM savings through avoided costs. Avoided costs include supply side and delivery costs, such as capital for distribution infrastructure, operating and commodity costs, avoided demand side costs such as operation costs, storage costs, transportation tolls, and demand charges.[79] The avoided distribution component of the avoided cost estimate is generally small relative to the total overall avoided costs.

2.5 Cost Recovery

There are two mechanisms for DSM cost recovery; the first is the Demand Side Management Variance Account (DSMVA). The DSM budget is considered a “Y” Factor and is built into rates once the budget has been approved by the Ontario Energy Board. The DSMVA account is used to track the variance between actual DSM spending by rate class versus the budgeted amount included in rates by rate class.

The second mechanism, a lost revenue adjustment mechanism, (LRAM), addresses lost revenues from DSM not included in the load forecast and, therefore, not incorporated into distribution rates. Distribution rates are based on consumption forecasts that take into account DSM as well as naturally-occurring energy efficiency. The LRAM allows a utility to recover the lost distribution revenue associated with DSM activity. The LRAM variance amount (LRAMVA) adjusts for margins the utility loses or gains if its DSM program is more or less successful in the period after rates are set, rather than what was planned when the rates were initially set. As outlined in the Guidelines, LRAMVA is used to track, by rate class, the impact of DSM activities undertaken in relation to the forecasted impact included in distribution rates.

2.6 Facilities Planning and DSM

Under the 2015-2020 DSM Framework, the Gas Utilities are required to provide evidence of how DSM has been considered as an alternative at the preliminary stage of project development for all distribution pipeline leave to construct facility investments. “The Board expects the gas utilities to consider the role of DSM in reducing or deferring infrastructure far enough in advance so that DSM can be considered a possible alternative. If a gas utility identifies DSM as a practical alternative, the utility may apply to the Board for incremental funds for a specific DSM program in the area that the system constraint has been identified.”[80]

[79] Other avoided costs such as avoided costs of upstream pipeline companies and natural gas producers are excluded. Ontario Energy Board. Filing Guidelines to the Demand Side Management Framework for Natural Gas Distributions (2015-2020). December 22, 2014. p. 34-35
[80] Ontario Energy Board. EB-2014-0134. Report of the Board. Demand Side Management Framework for Natural Gas Distributors (2015-2020). December 22, 2014. p. 36

2.7 Differences between the Gas Utilities' DSM Planning Processes

The DSM planning process is well established in Ontario, and the Gas Utilities follow the same guidelines, and generally face the same issues. The differences between the Gas Utilities reflect the difference in customer mix and geography, rather than differences in planning processes.

First, the Union Gas customer base has a higher share of industrial customers than Enbridge, leading to two significant differences in its DSM plans.

- Union's DSM savings are more highly focused on industrial customers, and customized DSM programs make up a greater share of the Union Gas DSM plan, and a greater share of the DSM savings than for Enbridge.
- Union allocates a modest share (about 7%) of total DSM expenditures for large volume (i.e., T2/R100 contract rate) customers, while Enbridge does not allocate any funding to DSM expenditures for transportation customers.

The Union Gas system also includes both transmission and distribution capacity, while the Enbridge system is primarily a distribution system. The difference in the structure of the Union Gas system does not change the facilities planning process, but does impact the way avoided costs are calculated in the evaluation of DSM programs.

- Enbridge's avoided costs include the cost of transportation to the Enbridge city gate.
- Union Gas' avoided costs include the incremental cost of Union's transmission system, which has the potential to be impacted by changes in demand on the Enbridge system, as well as other downstream sources of demand (e.g., Parkway).

3. Differences between Facilities Planning and DSM Planning Criteria and Approach

While DSM programs broadly impact facilities requirements, and the cost savings associated with a broad-based reduction in distribution and transmission costs are generally included in the DSM planning process via the avoided costs, the linkages between DSM planning and facilities planning are currently passive rather than active, and are not sufficient to actively integrate geo-targeted DSM programs into the facilities planning process.

There are a number of differences between the DSM and facilities planning processes that must be reconciled in order to potentially use geo-targeted DSM to reduce distribution facility investments. The most important are summarized below.

3.1 Differences in Risk and Reliability Criteria

One of the most challenging differences between the current DSM and facilities planning processes is the difference in risk and reliability criteria.

- The primary goal of facilities planning is to ensure the utility pipeline system is sufficiently sized to ensure that demand will not exceed the system capacity at design conditions. As a result, the facilities planning process is based on a primary philosophy of risk avoidance.
- The primary goals of DSM program planning are to reduce lifetime natural gas consumption and influence a culture of conservation.

DSM success is measured using a variety of metrics, but is often evaluated based on program participation rates rather than measurement of actual savings. Risk is inherent in DSM planning and implementation by design. The utilities are encouraged to innovate in their approaches to program delivery in order to increase program uptake.

The use of DSM to reduce the need for facility investments changes the balance of risk for the DSM program. For a DSM program to be relied upon as an alternative to a new facility investment, it needs to satisfy the same risk criteria as the facility investment it's replacing.

As highlighted earlier, the risks associated with facilities planning are not just financial; there is also the potential for gas system outages if facilities are insufficient. This risk is not present for standard DSM programs. If DSM programs fail to meet their objectives, the utility would be expected to identify and resolve the issues with the program, including potentially restructuring, redesigning, or canceling the program. There may be financial implications related to these changes but direct impact on consumers would be limited.

However, a DSM program implemented as an alternative to a new infrastructure project could lead to a shortage of system capacity if the program does not perform as intended, with potentially significant impacts on consumers. As a result, if a geo-targeted DSM program designed to reduce facility investments is non-performing and fails to deliver the expected savings, or if the savings appear to be uncertain during the evaluation phase, the utility will be required to proceed with the facility investment to ensure the same level of overall system reliability. This would lead to an increase in the overall cost of serving the load growth, as both the DSM costs and the facility investment costs would need to be recovered. In addition, the facility investment may need to be accelerated to meet the need, resulting in higher than anticipated or originally budgeted project costs.

The differences in risk and reliability are accentuated by the lack of information on the impact of DSM on peak hourly demand. While with certain exceptions, there is general agreement that DSM can impact peak hourly demand, there is little to no data available on the actual impact. The Gas Utilities have limited information on this, and there is only limited experience with it in other jurisdictions. The Gas Utilities also do not have measurement with sufficient granularity to accurately measure impacts of DSM on a per-customer basis, and have only slightly better measurement on a network-wide level.

3.2 Coordinating Facilities Planning and DSM Planning Timelines for Geo-Targeted DSM Programs

On an operational basis, DSM planning operates in a relatively short time-frame. The program planning schedule depends on the type of program (assuming that the program is being implemented in the current DSM Framework), and whether the policy issues described in the subsequent section are settled and an appropriate framework is developed.

The range of timing from the decision to implement a DSM program (or not) to actual implementation currently ranges from three months to one year. Implementation of a geo-targeted DSM program is expected to take some additional time, in order to determine the program boundaries and optimize the program design based on the specific area to be targeted. Hence, excluding any regulatory approval delays, the Gas Utilities could be able to implement a new geo-targeted DSM program within 12-18 months of the decision to proceed. This recognizes that the Gas Utilities have had no experience with geo-targeted program design and that these timeframes are based on broad-based DSM efforts. The timing may change as more is known about geo-targeted program design; the Gas Utilities expect to gain insight on these program enhancements during the course of their pilot studies.

The length of time that a DSM program needs to be in place (to reduce peak demand by enough to reduce the need for a specific facility investment) depends on the specific customer characteristics, the DSM program, and the specific facility investment. The rate of demand growth in the region served by the new facility will be particularly important. For facility investments in areas with rapidly growing demand, the DSM programs may need to be in place earlier in order to offset additional incremental demand growth necessary to reduce the need for incremental infrastructure.

The lack of information on the ability of natural gas DSM programs to impact peak demand makes it currently impossible to know with certainty when a DSM program needs to be implemented, and how long the program needs operate in order to successfully reduce the facility investment. The rate of demand growth that must be offset by the DSM program will also have a significant impact on the length of time that the DSM program will need to be implemented. However, the Gas Utilities anticipate that most geo-targeted DSM programs will require at least two to four years of fully effective implementation to reduce demand growth sufficiently to allow the facility investment to be reduced.

For a geo-targeted DSM program to reduce a facility investment, program results need to be in place with sufficient reliability to ensure that the new facility will not be required to meet demand. Generally, this would require a successful evaluation of DSM program results before the leave to construct filing. Given the need to evaluate the impacts, the DSM program would need to be completed, or demonstrate measurable results; at least two years prior to when the additional capacity was initially projected to be required.

Hence, a successful geo-targeted DSM program would need to be approved and put into motion approximately three to five years before the expected in-service date of the targeted facility investment. However, the need for new facilities is generally uncertain at this stage. As a result, geo-targeted DSM programs may need to be implemented before the Gas Utilities have a high degree of certainty that the facility investment will actually be required. This is likely to lead to DSM investments in areas where demand growth either accelerates or slows down, changing the amount of DSM necessary to reduce the facility investment, potentially leading to an expenditure on DSM that may not produce the full value as intended.

3.3 Addressing DSM Program Peak Hour Impact Uncertainty

As discussed later in this report, ICF expects most DSM measures to reduce peak day demand. However, there is little to no measured data on the impact of DSM programs on daily, as opposed to annual, demand. The ability of a given DSM program to achieve a specific level of peak hourly demand reduction is even less well understood.

The level of uncertainty related to the impact of DSM programs on peak hour demand has a significant impact on the ability of a utility to rely on DSM as an alternative to new facilities. To ensure, with sufficient reliability for planning purposes, that the impact of the DSM program on peak period demand is sufficient to reduce a facility investment, the DSM program needs to be designed to achieve greater peak period savings than the facility investment it replaces.

For example, a portfolio of DSM programs might have peak period impacts with a standard deviation of 10% around the expected impact. For the DSM program to meet the required peak period load reduction 95% of the time, it would need to be sized to meet 116% of the required capacity. The same program would need to be sized at 121% of the required capacity to meet requirements 98% of the time.

The magnitude of this required oversizing can be influenced by the timing of DSM program implementation. Earlier implementation of a DSM program would allow for additional monitoring and evaluation, and provide additional assurances that the facility could be constructed before the capacity is required, if the DSM program appears unlikely to achieve its objectives. In practice, the optimum planning process is likely to include both oversizing of the DSM programs, and maintenance of the ability to construct the facility if needed, to assure required system reliability.

4. Approach to the Integration of DSM with Facilities Planning

Using DSM to reduce future facility investments will need to be consistent with the utility imperative of maintaining the integrity of the natural gas system and providing safe and reliable service to customers. While the integration of DSM and facilities planning will depend in part of the resolution of the noted policy issues, several key components will need to be included in the end result, regardless of the policy outcomes:

1. Determine the potential impacts of DSM measures and programs on peak period demand
2. Integrate DSM impacts into the peak hour and peak day demand forecasts used to plan investments in new facilities
3. Identify facility investments with the potential to be reduced by DSM
4. Design and evaluate pilot geo-targeted DSM programs
5. Propose appropriate changes to regulatory policy needed to facilitate implementation of DSM programs targeted at reducing infrastructure investment
6. Engage stakeholders

Each of these topics is discussed in more detail below.

4.1 Determine the Potential Impacts of DSM Programs on Peak Period Demand

There is limited data available in the natural gas industry to assess the impact of DSM, energy-efficiency technologies, or new end-use technologies on peak day and peak hour demand. Instead, for this study, ICF relied on engineering estimates and aggregate data analysis of gate station data to estimate DSM savings potential. Gate station flows, however, are not reliable indicators of hourly end-use consumption across the gas distribution system. These are critical obstacles for integrating DSM expectations with facilities planning. Changes in demand resulting from DSM programs are inherently probabilistic and uncertain as to their timing. At present, given the absence of firm data on the effects of DSM, there is little confidence that DSM is a viable alternative to facility investment where service reliability is paramount.

As outlined in the sections below, the Gas Utilities use two approaches to improving the understanding of the potential impacts of DSM.

4.1.1 Assessment of Impact of DSM on Peak Period Requirements

This study estimated potential impacts of DSM programs on peak period demand in the Gas Utilities service territories, and looked at the following peak periods:

- **Peak period for distribution infrastructure:** The morning lift period (6-10 a.m.) surrounding the peak hour, with each hour being considered separately. This allows for some insights into how the demand impacts are shifting during this period.
- **Peak period for transmission infrastructure:** The demand during the peak day, considered as an aggregate. Transmission system requirements are impacted by both the morning lift period and changes to the peak daily volumes.[81]

As described in further detail in Section IV, the analysis leverages results from the OEB CPS and focuses on the development of load profiles for natural gas consumption and measure savings at the sub-sector and end-use level. These load profiles are used to estimate peak demand impacts and the analysis is calibrated to gate station data.

In the traditional DSM evaluation process, the impacts of conservation and efficiency measures are focused on annual energy savings. However, the impact of measures on peak hour or peak period demand can differ significantly from the impact on annual energy consumption. When considering impacts to peak hour, the measures fall into three distinct categories: peak demand savings, peak demand increases, or no impact on peak demand. Further details are provided in Section IV and these terms are further defined in the Terms of Reference.

4.1.2 In-field Pilot Study Identification and Monitoring

Pilot studies and in-field research aligned with actual proposed facility investments are required to properly assess whether or not DSM programs can be relied upon to reduce facility investments. The analysis of data collected during pilot studies and in-field research allows for the measurement of DSM program impacts on peak demand, the reliability of the DSM program in that endeavour, and the cost of the program relative to the measured results. The use of in-field studies:

- Minimizes lost opportunities by working with actual distribution pipeline systems
- Maximizes the value of the assessments by working with actual consumers in identified areas
- Maximizes the impacts of available resources

[81] Decreases in daily demand may not result in decreased facilities if the peak hour usage increases. This also includes distribution infrastructure modelled using transient analysis.

- Informs changes to facilities planning processes and analysis based on actual tested experience

The in-field studies will be targeted at specific facility distribution pipeline systems, and be focused on DSM measures expected to impact peak period demand. The studies will be designed to:

- Confirm peak period impacts of DSM measures
- Test DSM potential to impact peak period demand
- Assess potential to enhance/accelerate DSM program customer participation

Currently, Enbridge is in the field with a case study in the Deep River, Ontario area to measure the impact of customer DSM participation on throughput and peak period reduction at the gate station. Enbridge has a robust interconnected distribution system with few isolated "one way feeds." This area is one of the few networks in Enbridge's franchise that is isolated. The pilot study will include advanced metering reading (AMR) installed on houses in Deep River to develop more granular hourly consumption information.

Union Gas is also in-field with a case study in the Ingleside, Ontario area of its franchise. This system has similar attributes to Deep River.

4.2 Integration of DSM into Facilities Planning Requirements

The impact of historical broad-based DSM programs on facility investments is implicitly captured in the current facilities planning process. Customer usage is updated each year using consumption based on recent historical usage. The historical usage reflects the impact of broad-based DSM, but does not reflect anticipated or unknown future DSM program impacts. The Gas Utilities are evaluating whether the trends in use per customer can be projected into the future with confidence, and will use data collected during in-field studies to develop more reliable information to allow them to incorporate the impacts DSM programs into facilities planning.

4.3 Identification of Facilities Projects with Potential to be Deferred or Reduced by DSM

A number of factors must be taken into consideration when identifying facility investments that have the potential to be reduced through geo-targeted DSM programs:

- **Size of the proposed facilities project:** The Gas Utilities expect there to be minimum project size criteria for determining which facility investments should be evaluated for geo-targeted DSM efforts. Facility investments sized below a specific threshold would be unlikely to justify the effort, due to the overhead requirements associated with designing, implementing, and evaluating the geo-targeted DSM programs.
- **Reason for the proposed facilities project:** Facility investments necessary for system integrity (such as relocations and replacements) will not be considered for geo-targeted DSM programs.
- **Coordination with municipal development projects:** Facility investments with construction schedules set to correspond with municipal development projects (to avoid multiple construction projects along the same corridor) will be reviewed to determine if geo-

targeted DSM programs would allow the facility investment to be downsized or avoided, but will not be considered for geo-targeted DSM programs designed to delay facility investments.

- **Risk of understating facilities requirements:** Due to the potential risk of loss of load, the cost of under-sizing a facility investment is generally much greater than the cost of oversizing. This relative cost risk will be considered when determining which facility investments are appropriate for geo-targeted DSM programs.

4.4 Design and Evaluation of Pilot Geo-Targeted DSM Programs

The Gas Utilities will use the results of this IRP study and the pilot studies currently in-field to inform potential geo-targeted DSM programs. The potential DSM programs will be focused on promoting DSM measures that are expected to reduce peak period demand.

Once specific facility investments have been identified as potential opportunities for geo-targeted DSM programs, the prototype DSM programs will be optimized based on the customer mix and the demand growth targets needed to reduce the facility investment. The potential DSM program costs will be evaluated relative to the potential benefits of the program using the appropriate cost-effectiveness test.

Nevertheless, a key consideration will be the reliability of the peak period demand savings resulting from DSM measures. The Gas Utilities must have a high degree of confidence that DSM measures will deliver for these peak period demand savings to be incorporated in the facilities planning process. The costs of underserving customers on peak days (i.e., loss of load requiring a relighting effort) is greater than the avoided costs of facility investments.

5. Policy Considerations

ICF's review of the DSM and facilities planning processes at the Gas Utilities identified several potential barriers or concerns to using DSM to help reduce facility investments, and which should be addressed as policy issues. These include:

- Changes in the approval process for facility investment targeted DSM
- Allocation of facility investment and cost recovery risk
- Funding for additional research
- Cross-subsidization between customers and customer classes
- Discrimination between customers and customer classes
- Approval of incentives for non-general services customers
- Establishment of an appropriate leave to construct budget threshold for geo-targeted DSM programs
- Impact of Ontario carbon policy natural gas infrastructure requirements

Each of these issues is discussed below.

5.1 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 facility investment reductions create different DSM and facilities planning requirements. Geo-targeted DSM programs designed to reduce peak hour or peak day demand will need to be implemented much earlier in the facilities planning cycle, often before there is certainty around demand growth, and will have limited opportunity for revisions if the programs do not meet expectations. In addition, the ultimate impacts of the programs – reduction of infrastructure investment – will be subject to the general facilities planning uncertainty consistent with the necessary implementation timeframe.

As such, DSM programs and technologies targeted at infrastructure reduction may need to be subject to different business and regulatory constructs, cost-benefit analyses, and evaluation standards than standard DSM. Further research and consultation should take place on how this type of DSM should be integrated into the process for leave to construct approvals.

In assessing the level of DSM budget required, harmonizing the cost-benefit analysis screen of traditional DSM (TRC), with facility investment (Profitability Index based on E.B.O. 188) should be considered.

Additional work is needed to investigate how this type of DSM could be placed on the same return on investment footing as other facility investments within the context of leave to construct decision-making. Options for achieving this should be explored (e.g., whether this type of DSM should be rate-based).

5.2 Allocation of Risk

While planning the in-field pilot studies and reviewing additional analyses, the Gas Utilities currently face uncertainty regarding the reliability of DSM programs designed to reduce peak hour and peak day demand. DSM programs designed to reduce facility investments may not be successful if projected demand continues to increase despite the DSM program. Given the uncertainty inherent in the planning cycle, it is likely that this would occur on at least an occasional basis. Hence geo-targeted DSM programs may require an increase in acceptance of future DSM cost risk to facilitate a reduction for new facilities. As a result, there is an increase in risk and a potential increase in cost of relying on DSM programs as an alternative to facility investments.

This also leads to an assessment of relative risks as one of the critical issues to be addressed in the integration of DSM and facilities planning. How do the costs of underestimating facility investments compare to the costs of potentially overestimating facility investments? The risks of under-sizing a pipeline investment are significant in areas with potential future market growth because any cost reductions associated with it would be dwarfed by the costs of expanding the system to meet unexpected future growth. The cost-benefit calculation, therefore, becomes a fundamental risk assessment. Are the potential upfront savings sufficient to justify the future risk?

This leads to a number of policy questions:

- How much risk is appropriate? How should the risk of underestimating facility investments be weighted relative to the risk of overestimating them? Is the risk to society of potentially not having the necessary energy services in place acceptable? How would this risk be assessed?

- To provide reasonable assurance that system capacity will be available to meet demand, the Gas Utilities will likely need to develop plans for both geo-targeted DSM programs and the facility investments needed to meet demand if the DSM program is not successful. Alternatively, the DSM program will need to be oversized to minimize risk. In both cases, the Gas Utilities expect to incur additional costs that do not directly serve to meet system requirements. How will the Gas Utilities recover these additional costs?
- Who bears the risk if a geo-targeted DSM program does not lead to a reduction of a facility investment? In this scenario, the utility would have invested in geo-targeted DSM activities without reducing facility 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?

5.3 Funding for Additional Research

Incorporation of DSM to reduce facility investments as part of normal facilities planning will require additional certainty regarding the costs of geo-targeted DSM programs, and the impact of DSM programs on peak period demand, which will require additional data collection and research. The Gas Utilities will need regulatory approval to invest in, and recover the costs of the AMI necessary to collect hourly data on the impacts of DSM programs and measures.

5.4 Cross-Subsidization

Geo-targeted DSM programs have the potential to lead to cross-subsidization between customer classes. To avoid this situation, the use of DSM to reduce facility investments is likely to require a change in the allocation of the DSM expenditures.

Currently, DSM expenditures are allocated to the rate class for which the expenditures were incurred. This works well when the benefits of the DSM expenditure are primarily focused on the participating customers, achieving a passive deferral reduction of infrastructure. To protect non-participants in DSM, in the 2015-2020 DSM Framework, the OEB set an upper limit on the rate impact for a typical residential customer at $2.00 per monthly bill.[82] In the situation where the primary purpose of DSM is to reduce facility investment, attributing all of the DSM expenditures to the rate class for which the direct savings were incurred may need to be reconsidered.

This is quite different from the treatment of new facility investments. In general, facility investments made for the good of the general distribution system (e.g., upgrading to improve operations, replacing old pipe) become part of rate-base and are included in the tolls charged all customers across the franchise because all customers benefit.

The costs of facilities expansions into new communities may also be rolled in to general system costs to be shared across the franchise where benefits are deemed to outweigh the costs. There are also facility investments that benefit a limited number of customers, where policy

[82] The $2.00/month rate impact includes both the overall annual DSM budget plus the shareholder incentive, capturing the full annual cost of DSM to the customer.

dictates that a contribution-in-aid-of construction is appropriate. The franchise will benefit from increased throughput but at least part of the costs of the individual facilities are borne by the new customer(s).

If the investment in DSM necessary to reduce the infrastructure investment is not treated in the same way as the infrastructure costs would have been treated, there are likely to be cross-subsidization impacts between customers and customer classes

Further research by the Gas Utilities into how DSM, particularly geo-targeted DSM, affects general facilities planning and cost allocation could better inform decision makers on how to address the potential for cross-subsidization.

5.5 Customer Discrimination

By definition, the use of geo-targeted DSM programs to reduce facility 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. This leads to policy questions that will need to be addressed.

- Is it appropriate to subsidize customer energy efficiency based on location, potentially providing special incentives to customers on one side of the street, while denying those incentives to customers on the other side of the street, or in other nearby locations?

A geo-targeted DSM program designed to impact peak hour requirements may also result in differences in incentives available based on customer characteristics, leading to additional customer discrimination:

- Customers in smaller homes are less likely to be creating significant new gas loads, and are therefore less likely to be the audience for geo-targeted DSM. This could result in a high proportion of the incentive payments being paid to customers that are generating the increased peak load, through increases to housing size and/or additional natural gas equipment.
- As a result, the overall costs of geo-targeted DSM may be inappropriately distributed to customers in older, smaller, less efficient homes.
- Commercial/industrial customers in a geo-targeted area may receive incentives or offers not available to their competitors in other areas, allowing for an unequal economic advantage.

5.6 Incentives for Non-General Services Customers

Achieving the DSM market penetration necessary to defer or reduce new facility investments is likely to take several years of targeted DSM activity. Given the relative timeframes for DSM program implementation, geo-targeted DSM programs designed to reduce facility investments and which target new communities may need to target contract customers, who arrange their own gas supply and transmission pipeline transportation, and who may or may not have transportation contracts on the distribution system. This would not be allowed under the current DSM Framework. Is it appropriate to provide DSM subsidies to consumers that are not current customers, with the expectation that they might become customers in the future?

In addition, the need for much of the facility investments, particularly in the Union Gas system, is driven by the growth in firm transportation (FT) demand by large industrial customers who also contract for their own supply and upstream pipeline transmission capacity. These customers contract for a specific level of pipeline capacity to meet their needs. However, in the Gas Utilities' experience, when these customers participate in DSM programs, they typically do not reduce the amount of FT capacity that they hold on the distribution or transmission system. Instead, they hold on to the capacity to ensure that they have access to the capacity in the future if their requirements increase, or use the capacity to meet new loads.

What this behavior tends to do is free up transmission and transmission pipeline capacity to the extent that these customers reduce their peak daily demands. But a geo-targeted DSM program aimed at these customers might not have any impact on facility investments, unless the program provides a sufficient incentive to the customer for the customer to release the FT capacity. This is likely to require different types of incentives or larger incentives than are currently offered by the Gas Utilities, and would also require contracting terms that would discourage these customers from requesting additional capacity in the future.

5.7 Establishment of an Appropriate Leave to Construct Budget Threshold for Geo-Targeted DSM Programs

Current guidance from the OEB suggests that energy-efficiency programs should be considered during the planning for each facility investment brought before the OEB as part of a leave to construct application. The threshold for these applications is currently $2 million, as outlined in the OEB Act 1998, part VI, Sect 90. However, developing, implementing, modelling, and evaluating geo-targeted DSM programs as an alternative to a specific facility investment is expected to be time consuming and may require additional internal resources to perform the modelling, conduct the analysis, and investigate alternatives. Hence, considering DSM as an alternative to facility investments is likely to make sense only for those facility investments with significant savings potential.

5.8 Appropriate Cost-Effectiveness Testing

Geo-targeted DSM programs may have benefits that combine the attributes of facilities planning and DSM programs (e.g., where a combination of DSM and facility investment reduces overall costs of serving the community). In this case the program should be evaluated considering the end user resource costs and the benefits of the DSM program on energy consumption (traditional DSM) and on its ability to reduce facility investments based on the impact on peak hour/peak day demand (traditional facilities planning).

The Gas Utilities consider a combined approach to cost-effectiveness testing to be appropriate for geo-targeted DSM programs. Benefits should include the direct cost savings associated with the reduced infrastructure plus the annual energy savings associated with the program. Costs should consider both the ratepayer and societal costs of developing and implementing the targeted DSM programs. The cost-effectiveness criteria also need to address the increase in risk associated with geo-targeted DSM programs. Ultimately, the cost of the resource to the consumer should be considered in facilities planning, with the affordability of energy supply a factor in the decision-making process, and whether or not other resources are a viable alternative. If the deferral of a geo-targeted facility investment would result in fuel switching to a more expensive energy source, this should be recognized and the additional costs to the end-use consumer fully valued.

5.9 Carbon Policy Measures Impact on Natural Gas Infrastructure Requirements

Carbon policy measures to date have focused on reducing energy consumption per unit of activity (akin to DSM energy-efficiency measures) and reducing the GHG intensity of the energy consumed (fuel switching). As such, we can conclude that current climate change policies:

- Could influence forward consumption of natural gas modestly (up or down) in the 2015-2020 timeframe and would likely impact demand downward in the 2021-2030 timeframe and beyond
- Would need to influence forward consumption for natural gas downward to meet 2030 and 2050 vintage reduction targets

However, carbon policy measures have not considered the impact on peak demand for natural gas as a primary or secondary benefit in a demonstrable way. Thus, any impact on peak demand would appear to be serendipitous and not by design. Further, measures such as adaptive thermostats, which are being promoted to reduce annual natural gas consumption and GHG emissions, are expected to increase the hourly peak of natural gas demand, potentially increasing the need for natural gas reinforcement infrastructure.

IV. DSM Potential to Impact Peak Day and Peak Hour Demand

This section focuses on the approach and results of ICF's estimates of the potential impacts of DSM measures on natural gas peak demand in the Gas Utilities' Ontario service territories. The estimated impacts on natural gas peak demand are subsequently used in Section V to assess the potential for DSM programs to reduce facility investments.

Utility distribution infrastructure requirements are largely determined by the peak hourly demand, while larger transmission system infrastructure requirements are primarily determined by peak day demand.[83] To assess the potential for DSM to reduce future facility investments, the DSM impacts analysis considered four peak periods for distribution infrastructure (peak demand periods #1-4) and one peak period for transmission infrastructure (peak demand period #5), as defined in the Terms of Reference.

1. Approach

This section documents the approach used for the peak period demand impact analysis. This includes the approach used to develop the base year and reference case scenarios and the achievable potential peak period demand savings. Although the technical and economic potentials were estimated as part of ICF's analysis, this report does not focus on those results since they are more theoretical and less instructive.

1.1 Base Year

The development of a base year allowed for an estimate of how peak demand is broken down amongst the relevant sub-sectors and end-uses in each utility service territory. This section describes the approach used to develop the base year peak demand estimates for the residential, commercial and industrial sectors. This section is organized as follows:

- **High-Level Overview:** Provides a high-level overview of the approach, with a focus on how the components are related and flow into each other
- **OEB CPS Base Year Analysis:** Includes a high-level description of the OEB CPS, which served as the starting point for the analysis
- **IRP Study Segmentation:** Summarizes the segmentation that was used as part of this study, including how the residential, commercial and industrial sectors were segmented into sub-sectors and end-uses
- **General Load Profiles:** Provides details on the development of general load profiles, including hourly utility gate station and industrial customer meter data provided by the Gas Utilities, a high-level description of some required modifications, and the approach that was employed to develop general load profiles of a representative design day

[83] There also continues to be an hourly component in the transmission system design, which may drive facilities if the peak hour increases more than the peak day demand decreases.

- **End-Use Load Profiles:** Details the approach used to develop hourly load profiles for each of the sub-sectors and end-uses included in the analysis. The section also compares the representative design day based on building modeling with the representative design day derived from utility hourly meter data
- **Macro Modeling and Calibration:** Summarizes how the hours-use factors were leveraged to estimate peak demand impacts for each of the Gas Utilities and how the results were calibrated

1.1.1 High-Level Overview

This section provides a high-level overview of the approach used to develop the base year peak demand estimates for the residential and commercial sectors, and the industrial sector, respectively. As depicted in Exhibit 7, the approach for the residential and commercial sector can be summarized as follows:

General load profiles:

- The Gas Utilities provided hourly 2014 meter data for its customers, including gate station data, hourly meter data from a subset of industrial customers, and hourly meter data for power producers
- Where necessary, the hourly meter data for industrial customers was scaled to reflect the entire industrial sector based on the annual consumption data from the OEB CPS
- A general residential and commercial sector load profile was created by subtracting the load profiles for the industrial sector and power producers from the overall gate station data
- Load profiles for the 10 coldest days were averaged to create a general residential and commercial sector load profile for a typical cold winter day
- A general residential and commercial load profile for a representative design day was created by scaling the general load profile for a typical cold winter day based on the Gas Utilities' design day HDDs
- This general load profile was used for calibration purposes (described below)

End-use load profiles:

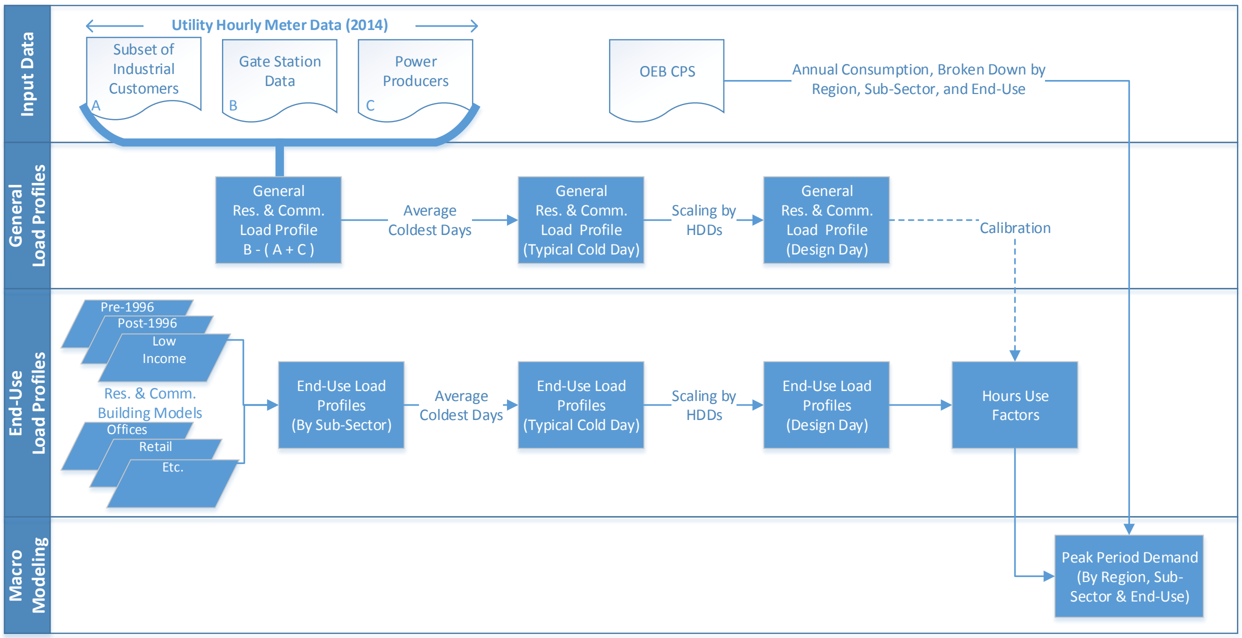
- Utility customers were segmented into sub-sectors containing buildings with similar energy-use patterns and the major energy end-uses within each sector were selected
- Representative building models were created for each sub-sector
- Hourly load profiles were extracted from the building models for each combination of sub-sector and end-use (e.g., space heating in the offices sub-sector)
- End-use load profiles for the 10 coldest days were averaged to create load profiles for a typical cold winter day
- End-use load profiles for a representative design day were created by scaling the load profiles for a typical cold winter day based on the Gas Utilities' design day HDDs

Macro modeling and calibration:

- The representative design day load profiles created based on the building modeling were used to produce hours-use factors, which allow for peak demand to be estimated based on annual consumption

- The hours-use factors were adjusted through a calibration process that involved comparing the general load profiles created with the utility hourly meter data against the aggregate of all of the end-use load profiles created based on building modeling
- The calibrated hours-use factors were applied to data from the OEB CPS to produce an estimated breakdown of peak demand

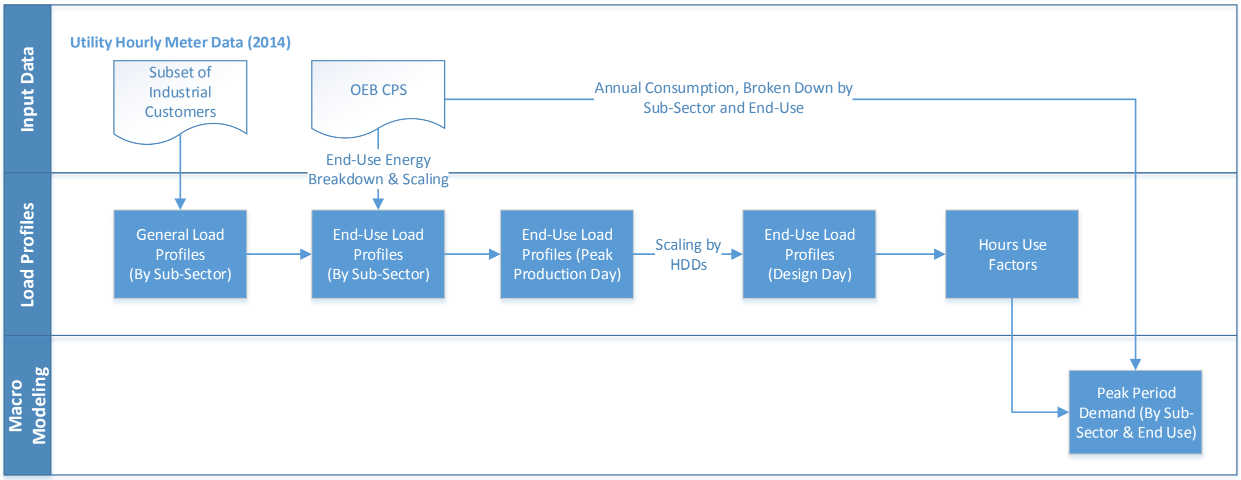
Exhibit 7 Overview of Base Year Approach for Residential and Commercial Sectors



The process for the industrial sector analysis is similar in many respects, although building models were not created for the industrial sector. As depicted in Exhibit 8, the approach for the industrial sector can be summarized as follows:

- The Gas Utilities provided hourly 2014 meter data for a subset of industrial customers
- Where necessary, the hourly meter data for industrial customers was scaled to reflect the entire industrial sector based on the annual consumption data from the OEB CPS
- The end-use breakdown in the OEB CPS was used to estimate the breakdown of energy consumption amongst the industrial end-uses
- The load profile for the peak winter production day was assumed to coincide with the utility peak day
- End-use load profiles for a representative design day were created by scaling the space heating component of the peak winter production day based on the Gas Utilities' design day HDDs
- The representative design day end-use load profiles were used to produce hours-use factors, which allow for peak demand to be estimated based on annual consumption
- The hours-use factors were applied to data from the OEB CPS to produce an estimated breakdown of peak demand

Exhibit 8 Overview of Base Year Approach for the Industrial Sector



1.1.2 OEB CPS Base Year Analysis

During 2016, ICF completed an OEB CPS study that focused on estimating the achievable potential for natural gas efficiency in Ontario from 2015 to 2030. The study was completed on behalf of the OEB and in consultation with the Gas Utilities and is summarized below.

- **Sector Coverage:** The study addressed three sectors: residential, commercial,[84] and industrial
- **Geographical Coverage**: The study results were presented for the total Union Gas and Enbridge Gas Distribution franchise areas and further broken down into the regions shown in Exhibit 9

Exhibit 9 Breakdown of Utility Franchise Areas and Regions

Utility	Union Gas	Enbridge Gas Distribution
Region	Northern[85]	Central
	Southern[86]	Eastern

The base year for the OEB CPS, which forms the starting point for the analysis, was calendar year 2014. This milestone provided a detailed description of "where" and "how" natural gas was used in each sector. The bottom-up profile of energy-use patterns and market shares of energy-using technologies was calibrated to actual Union Gas and Enbridge Gas Distribution customer billing data.

Completion of the base year portion of the OEB CPS study involved the following steps:

- Utility customers were segmented into sub-sectors containing buildings with similar energy-use patterns

[84] The term "commercial" also included institutional sectors, such as schools, hospitals, etc.
[85] Throughout Northern Ontario, from the Manitoba border to the North Bay/Muskoka area and across Eastern Ontario from Port Hope to Cornwall
[86] Southwestern Ontario from Windsor to just west of Toronto

- The major energy end-uses within each sector were selected
- Detailed sub-sector archetypes were developed and used to create building energy-use models for each sub-sector

1.1.3 IRP Study Segmentation

The base year results from the OEB CPS also formed the starting point for the IRP study. As such, calendar year 2014 was selected as the base year for the IRP study as well. This was a useful point of departure for the study since the base year results are broken down at a detailed level and calibrated to actual annual utility sales data. For example, the base year results provide estimates of the annual energy consumption for space heating in offices in Enbridge's central region.

The following subsections detail the sub-sectors and end-uses that were selected for the IRP study and how these categories relate to the sub-sectors and end-uses employed for the OEB CPS. The sub-sectors and end-uses for the IRP study analysis were selected in consultation with the Gas Utilities' staff.

Residential Sector

Exhibit 10 and Exhibit 11 summarize the residential sub-sectors that are included in the IRP study analysis, including a comparison of the categories that were included in the OEB CPS.

Exhibit 10: Summary of Residential Sub-Sectors Employed in IRP Study

OEB CPS Sub-Sectors	IRP Study Sub-Sectors	Notes
Single detached, gas-heated, pre-1980	All segments, pre-1996	Combined dwellings built pre-1996 into a single category
Single detached, gas-heated, 1980-1996		
Attached, gas-heated, pre-1980		
Attached, gas-heated, 1980-1996		
Other/Mobile, gas-heated		Too small to consider alone, fits best here
Other segments, not gas-heated		Too small to consider alone, fits best here
Single detached, gas-heated, 1997-present	All segments, 1997-present	Combined dwellings built 1997-present into a single category
Attached, gas-heated, 1997-present		
Low-income detached, gas-heated, all ages	Low-income	Utility focus on low income programs
Low-income attached, gas-heated, all ages		
Low-income, not gas-heated, all ages		

Exhibit 11: Summary of Residential End-Uses Employed in IRP Study

OEB CPS End-Use	IRP Study End-Use	Notes
Space Heating Fireplaces	Space Heating	Combined space heating and fireplaces
Domestic Hot Water Swimming Pool Heaters Other Gas Uses Clothes Dryers Cooking Appliances	DHW and Other	DHW end-use is important Other end-uses combined account for only 10% of the baseline consumption and 5% of the unconstrained achievable potential in 2020

Commercial Sector

Exhibit 12 and Exhibit 13 summarize the commercial sub-sectors that are included in the IRP study analysis, including a comparison of the categories that were included in the OEB CPS.

Exhibit 12: Summary of Commercial Sub-Sectors Employed in IRP Study

OEB CPS Sub-Sectors	IRP Study Sub-Sectors	Notes
Large Office Medium Office	Offices	Combine both office sizes into one office category
Large Non-Food Retail Medium Non-Food Retail Food Retail	Retail	Combine all retail buildings types into Retail sector
Large Hotel Medium Hotel	Hospitality	Combine both hotel sizes into Hospitality sector
Hospital Nursing Home	Healthcare	Combine hospital and nursing home into healthcare sector
School University/College	Education	Combine educational facilities into education sector
Apartment	Apartment	Unchanged from OEB CPS
Apartment (Low Income)	Apartment (Low Income)	Utility focus on low-income programs
Restaurant	Restaurants	Unique load profile
Warehouse/ Wholesale Other	Other	Warehouses more similar to Other. Building types included in the original Other sub-sector are community centres, fire halls, religious buildings, and theatres.

Exhibit 13: Summary of Commercial End-Uses Employed in IRP Study

OEB CPS End-Use	IRP Study End-Use	Notes
Space Heating	Space Heating	Unchanged from OEB CPS
Service Water Heating Other CHP	DHW and Other	Combined, Other and CHP end-uses only account for 5% of the baseline consumption and 1% of the achievable potential savings by 2020
Food Service	Food Service	Unchanged from OEB CPS

Industrial Sector

Exhibit 14 and Exhibit 15 summarize the industrial sub-sectors that are included in the IRP study analysis, including a comparison of the categories that were included in the OEB CPS.[87]

Exhibit 14: Summary of Industrial Sub-Sectors Employed in IRP Study

OEB CPS Sub-Sectors	IRP Study Sub-Sectors	Notes
Cement and Asphalt Manufacturing	Mineral Processing Industries	
Non-Metallic Mineral Product Manufacturing		
Mining, Quarrying, and Oil and Gas Extraction	Resource Extraction Industries	Also includes forestry, fishing, and hunting services, which were included in the Miscellaneous Manufacturing sub-sector in the OEB CPS
Chemical Manufacturing	Heavy Process Industries	
Pulp, Paper, and Wood Products Manufacturing		
Petroleum and Coal Product Manufacturing		
Primary Metal Manufacturing		
Fabricated Metal Manufacturing	Manufacturing Facilities	Unlike the OEB CPS, the Miscellaneous Manufacturing sub-sector does not include Agriculture (NAICS 11) for the IRP study
Miscellaneous Manufacturing		
Transportation and Machinery Manufacturing		
Food and Beverage Manufacturing		
Greenhouses	Greenhouses & Agriculture	Agriculture is limited to crop and animal production and aquaculture (NAICS 111, 112) and does not include forestry, fishing, and hunting services (NAICS 113, 114, 115), which have instead been included in the Resource Extraction Industries sub-sector as part of the IRP study
Agriculture		
Utilities	**N/A (Excluded)**	Excluded since DSM potential is very small

Exhibit 15: Summary of Industrial End-Uses Employed in IRP Study

OEB CPS End-Use	IRP Study End-Use	Notes
Direct Heating	Direct Heating	Unchanged from OEB CPS.
Steam and Hot Water Systems	Steam and Hot Water Systems	These end-uses were merged since they are both driven by process steam.
CHP Steam		
Heating and Ventilation	HVAC and Other	HVAC was merged with Other Processes since the latter represents less than 1% of consumption.
Other Processes		
Gas Turbine	**N/A (Excluded)**	These end-uses are excluded from the IRP study since DSM potential is very minimal
Steam Turbine		

[87] As per the data the Gas Utilities provided for the OEB CPS and the analysis completed for that study, the industrial sector excludes certain rate classes ineligible for DSM. For example, Union Gas' Rates 25, 30, M10, T3, T9 are excluded from the industrial sector analysis.

1.1.4 General Load Profiles

This section outlines the approach that was used to develop general load profiles based primarily on hourly meter data provided by the Gas Utilities. This includes an overview of the data and the resulting general profiles for both the residential and commercial sectors, and the industrial sector.

Utility Hourly Meter Data

The Gas Utilities provided hourly gate station data for the base year of 2014. The gate station data represents the hourly natural gas demand across all sectors, including power producers, and was provided separately for each study region (i.e., Central and Eastern regions for Enbridge, Northern and Southern regions for Union Gas). In addition to the gate station data, the Gas Utilities provided ICF with 2014 hourly meter data for power producers and each industrial sub-sector on a regional basis. This information was used to disaggregate the gate station data into separate load profiles for power producers, the industrial sector, and a third profile representing the combined residential and commercial sectors.

Issues with Utility Gate Station Data

Utility staff noted that, although gate station data provides a reasonable estimate of hourly demand, there are several factors that impact the ability of the gate station data to represent average customer behavior. This includes the following items:

- The Gas Utilities have several long laterals in excess of 100 km and the line pack in this piping tends to dampen the flow and pressure peaks at the gate station
- A couple of the long laterals have compressors, whose intermittent operation dramatically impacts gate station flows
- One of the utilities' long laterals can be shut in for several hours or can be packed up to meet gas nominations on the system
- The Gas Utilities experience line hits that can increase gate station flows, even though the gas is not being consumed by customers
- The Gas Utilities have maintenance activities that can involve blowing down, flaring, or purging gas that can be seen at the gate stations, but is not consumed by customers
- The Gas Utilities install many kilometres of pipe each year that need to be gassed up. This gas flows through their gate stations, increasing base system line pack, but is not consumed by customers
- The operation pressures of some of the systems can vary by season
- Maintenance work at gate stations can result in unusual or missing data
- Union Gas has many unregulated gate stations that will flow greater or less than actual consumption if TransCanada/Dawn to Parkway pressures increase or decrease (i.e., their compressors cycle on/off)
- Union Gas has some small systems that did not have hourly data in 2014
- Union Gas has more than 200 local producers that feed into its system and only a handful have hourly data, with the remainder having daily or monthly data

Data Cleaning

ICF thoroughly examined both the gate station and the hourly industrial customer consumption data provided by the Gas Utilities to identify any potential data integrity issues. The following issues were identified and addressed:

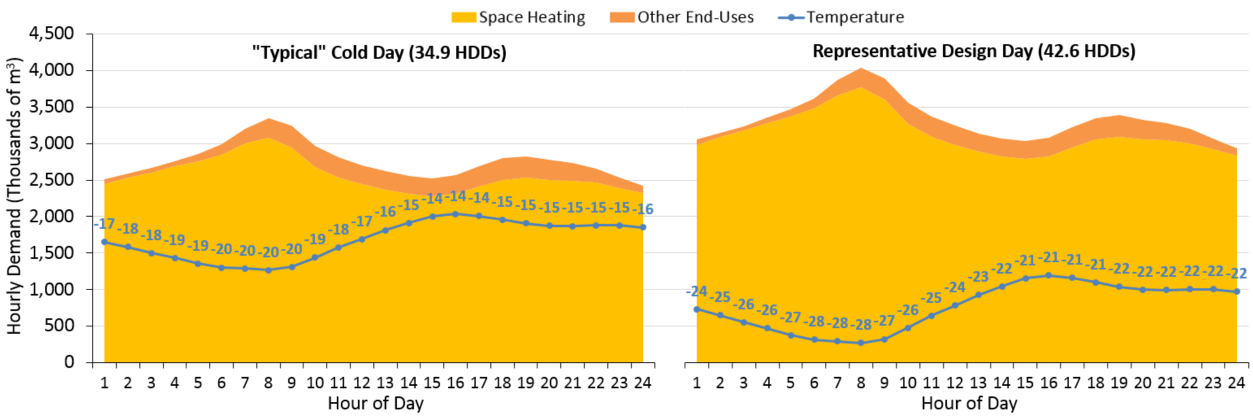
- **Missing hourly data:** For some sub-sectors, the 2014 gate station data did not contain a full record (all 8,760 hours) of energy consumption. Energy consumption for the missing hours was estimated either through the use of the adjacent data values or data for similar time periods on adjacent days.
- **Daily consumption data:** Some industrial customers do not have hourly meter reads and instead have daily meter reads that appear in the data as a single entry occurring at 11 a.m. The inclusion of these customers in the dataset led to inaccurate demand spikes at 11 a.m. on a daily basis. Therefore, industrial customers without hourly meter reads were removed from the dataset.
- **Missing industrial customer data:** Although the 2014 industrial consumption data provided by the Gas Utilities included most of its customers, hourly information was not available for all. Therefore, the available hourly consumption data was used to develop a representative load profile for each industrial sub-sector, which was then scaled up to match the annual energy consumption reported in the OEB CPS.
- **Inconsistent data points:** The 2014 industrial data also had certain distinct periods throughout the year where there was a sudden drop in energy consumption. These “demand cliffs” were defined as any hour in which the demand drops by 50% or greater from the preceding hour. Consultations with the Gas Utilities' staff indicated that these inconsistencies were caused by missing hourly data for a subset of the industrial customers. To address this issue, the energy consumption for the affected hours was replaced by an average of the energy consumption for the same hour of the day on the day before and the day after.
- **Annual industrial sub-sector consumption:** On a sub-sector by sub-sector basis, the annual sum of the industrial hourly energy consumption data did not perfectly match the annual energy consumption reported in the OEB CPS. Based on consultations with the Gas Utilities' staff, it was determined that these discrepancies are likely the result of missing data from certain customers and slight differences in how the sub-sectors were binned in each study. The discrepancies were corrected by scaling the hourly consumption data to match the annual consumption as reported in the OEB CPS.

Residential and Commercial Sectors

A general load profile was developed for the residential and commercial sectors by subtracting the hourly power producer and industrial sector demand from the gate station totals. Careful consideration was given when developing the representative design day load profile for the aggregated residential and commercial sectors. During this process, it was noted that the general load profiles for two weekdays with similar HDDs varied significantly if the days had different temperature profiles (e.g., a consistently cold day versus a day that is extremely cold in the morning then warming up throughout the day). It was also noted that peak demand is generally greater on weekdays than on weekends, indicating that only weekdays should be considered for the representative design day analysis.

Since the weather profile for the coldest day in 2014 was not necessarily typical, and was also warmer than the Gas Utilities' design day in term of HDDs, ICF created a typical cold weekday by averaging the temperature and load profiles of the coldest 10 weekdays in 2014. A load profile for the representative design day was then derived by scaling up the space heating component of this typical cold day based on the HDDs of the design day relative to the typical cold day, as shown in Exhibit 16.[88]

Exhibit 16: Aggregate Residential and Commercial Sector Load Profiles for Typical Cold Day and Representative Design Day for Enbridge's Central Service Territory, Based on 2014 Consumption Data



Industrial Sector

Hourly metered data from a subset of industrial customers was used to inform the shape of the industrial sector's load profile,[89] while annual consumption estimates from the OEB CPS were used to inform the magnitude of the load profile. Compared to the residential and commercial sectors, the load profile for the industrial sector was relatively flat and only loosely correlated to weather, as exemplified by Exhibit 17 which shows the industrial sector load profile for Union Gas' North region on its peak production day.

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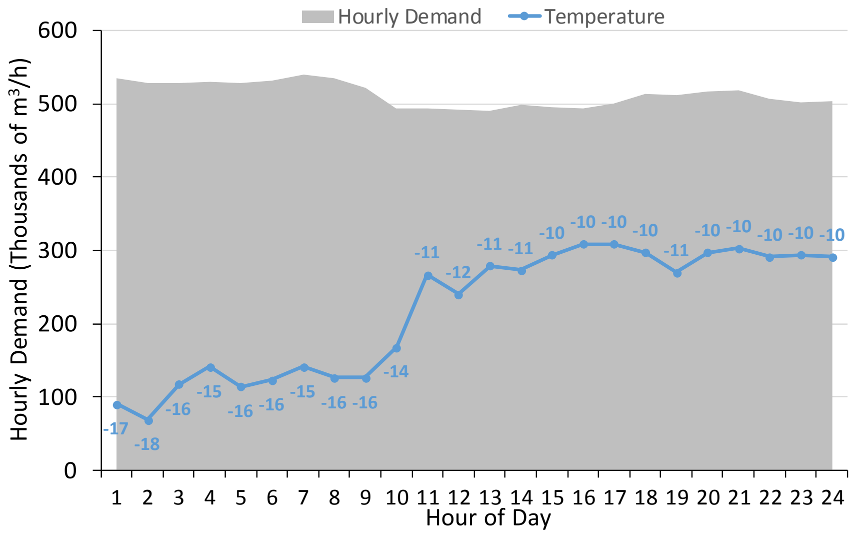
[88] It should be noted that the gate station data does not differentiate between end-uses. Therefore, the space heating component shown in Exhibit 16 was estimated based on additional analysis completed during the building modeling component of this study, described in Section IV.1.1.5.

[89] As per the industrial sector segmentation, the Utilities (i.e., power producers) sub-sector was removed and not further analyzed as part of this study.

Exhibit 17: Industrial Load Profile for Union Gas' North Region on the Peak Production Day



Because production levels are the primary driver of industrial demand, the industrial sector's maximum contribution to the representative design day load profile was estimated by superimposing the peak production day onto the Gas Utilities' HDD-based design day. The first step in this process was to estimate the breakdown of the industrial sector load profile by end-use. Next, demand attributed to the HVAC and Other end-use was scaled to meet the HDDs of the design day temperature profile. The methodology employed to carry out this task is detailed in the following section.

1.1.5 End-Use Load Profiles

This section documents the approach that was used to develop sub-sector and end-use specific hourly (8,760 hours) load profiles for residential, commercial, and industrial customers in the Gas Utilities' service territories. Hourly load profiles were created for each combination of sub-sector and relevant end-use, as detailed in Section 1.1.3. For example, ICF created an hourly load profile for the space heating end-use in the offices sub-sector.

The hourly load profiles provided reasonable estimates of the distribution of natural gas consumption throughout the year, accounting for differences on a daily, weekday vs. weekend, and seasonal basis. As described in more detail in Section 1.1.6, these load profiles were an important input into the estimates of peak demand for each of the peak periods being considered.

Residential Sector

To create residential building models, it was necessary to determine characteristics for a representative residential home for each of the residential sub-sectors included in the analysis. As detailed previously in Section 1.1.3, this includes the Pre-1996, Post-1996, and Low Income sub-sectors. The building characteristics summarized in Exhibit 18 were obtained from HOT2000 models created by ICF for the OEB CPS. Using the building characteristics, representative building energy models were created in BEopt™ (Building Energy Optimization), a user-friendly front-end to EnergyPlus, which is used to model homes.[90] BEopt was used rather than HOT2000 since it can produce hourly results. The buildings were simulated using 2014 weather data for each region. These detailed weather files include hourly values for dry and wet bulb temperatures, wind speed and direction, and solar irradiance.

Exhibit 18: Residential Housing Modeling Parameters

Parameter	House Vintage		
	Pre-1996	Post-1996	Low Income
Area (ft^2)	1,985	2,173	1,786
# of Stories	2 + Basement	2 + Basement	2 + Basement
Wall RSI (m^2K/W)	1.99	4.23	1.79
Roof/Attic RSI (m^2K/W)	3.78	7.04	3.40
Infiltration (ACH_{50})	6.29	3.40	6.92
Window to Wall Ratio	12.4%	13.5%	12.4%
Window Solar Heat Gain Coefficient	0.6457	0.5986	0.6457
Window U-Value (W/m^2K)	3.89	3.00	4.28

The building models were designed to provide an estimate of the hourly load profile for each residential sub-sector and end-use combination (e.g., space heating end-use in pre-1996 dwellings). In contrast, hourly utility data provides limited granularity since the Gas Utilities' facilities are designed to meet the potential aggregate load from all of the customers served by the facility. This can range from a single customer when designing a service line, to several hundred or thousand customers when designing system expansions to new communities and system reinforcements resulting from customer growth.

The first set of residential load profiles generally had daily profiles with very high peak-to-trough ratios, representative of an individual home with aggressive overnight setback. These load profiles were not representative of the aggregate profile of an entire building stock with varying schedules and occupancy patterns. In general, this "peakiness" was also not present in gate station data that was provided by the Gas Utilities. The following strategies were used to adjust the end-use load profiles to be representative of the entire stock of buildings in the Gas Utilities' service territories:

- **DHW schedules:** The modified version of the domestic hot water (DHW) use schedule from the U.S. Department of Energy (DOE) Midrise Apartments archetype was used to approximate the DHW schedule for the residential sector.
- **Infiltration schedule:** The original space heating load profiles contained three notable daily peaks that were concurrent with spikes in the infiltration schedule caused by early morning bathroom ventilation, late morning clothes dryer usage, and evening stove top usage. These spikes were removed by assuming an average constant infiltration rate, which is more representative of the building stock.
- **Summer heating loads:** The building models included summer heating loads in homes. In reality, space heating systems may not even be available during the summer months (e.g., HVAC systems in cooling mode) and much of this potential heating would occur overnight, when homeowners are likely to let space temperatures drift a bit lower. As such, space

[90]NREL (National Renewable Energy Laboratory), BEopt: Home. https://beopt.nrel.gov/

heating demand was manually removed during the summer months (i.e., mid-June to mid-September).

- **Space heating schedules:** To account for the differing space heating schedules in the building stock and the diversity of the building stock in general, representative space heating schedules were modified to reflect an aggregation of a large number of homes with different space heating requirements and schedules.

The end-use load profiles for each residential sub-sector were used to generate representative design day load profiles using an approach similar to the one used for the general load profiles (as outlined in Section 1.1.4). First, the end-use load profiles of the 10 coldest weekdays were averaged to create typical cold day load profiles. The load profiles for the space heating end-use were then scaled up by the ratio of the design day HDDs to the HDDs of the typical cold day.

Commercial Sector

U.S. DOE Commercial Reference Building archetype models were used as the basis for modeling buildings in the commercial sector.[91] These are a set of 16 normative EnergyPlus building energy models that were created based on the U.S. Energy Information Administration's (EIA) 2003 CBECS (Commercial Building Energy Consumption Survey) results, and are summarized in Exhibit 19. The exhibit also summarizes the reference building type that was used to represent each of the IRP building types. Since the "other" sub-sector represents a wide variety of buildings, including warehouses, community centres, arenas, fire and police stations, and churches, it was represented as a mix of warehouses, offices, and education building types.

Exhibit 19: DOE Commercial Reference Building Types

DOE Building Type	Floor Area (ft^2)	# Floors	IRP Building Type
Large Office	498,588	12	-
Medium Office	53,628	3	Offices
Small Office	5,500	1	-
Warehouse	52,045	1	Included in Other
Stand-alone Retail	24,962	1	Retail
Strip Mall	22,500	1	-
Primary School	73,960	1	-
Secondary School	210,887	2	Education
Supermarket	45,000	1	-
Quick Service Restaurant	2,500	1	-
Full Service Restaurant	5,500	1	Restaurants

[91] U.S. DOE, Office of Energy Efficiency and Renewable Energy, Commercial Reference Buildings. https://energy.gov/eere/buildings/commercial-reference-buildings

DOE Building Type	Floor Area (ft^2)	# Floors	IRP Building Type
Hospital	241,351	5	Healthcare
Outpatient Health Care	40,946	3	-
Small Hotel	43,200	4	-
Large Hotel	122,120	6	Hospitality
Midrise Apartment	33,740	4	Apartments

Specific variants of the U.S. DOE archetypes exist for a variety of climate zones and vintages (see Exhibit 20 and Exhibit 21 below). The climate zone and vintage variants have different assumptions from a building construction standpoint (e.g., higher insulation values assumed in colder climates). For modeling purposes, each of the four locations (Toronto, North Bay, Ottawa, and London) was matched to the appropriate climate zone as shown in Exhibit 20,[92] while the 1980-2004 vintage was selected for all building types since it best represents the average age of commercial buildings in Ontario. To ensure consistency with the residential sector results, the same 2014 weather files were used for the commercial sector models.

Exhibit 20: Climate Zones Included in DOE Commercial Reference Building Archetypes[93]

Climate Zone	Representative City	Average HDDs, 2014-2016	IRP Study Region and Representative City	Average HDDs, 2014-2016
5A	Chicago, Illinois	3,300	-	-
5B	Boulder, Colorado	2,978	-	-
6A	Minneapolis, Minnesota	3,981	Central (Toronto) South (London) East (Ottawa)	3,639 3,866 4,385
6B	Helena, Montana	3,992	-	-
7	Duluth, Minnesota	4,781	North Bay	5,052
8	Fairbanks, Alaska	6,926	-	-

[92] The most representative climate zone for each location is specified in weather data files and is based on aggregate weather data, including heating degree days, cooling degree days, wind speed and direction, and solar irradiation.
[93] Warm climate zones (1A-4C) are not shown since they are not relevant to this analysis.

Exhibit 21: Vintages Included in DOE Commercial Reference Building Archetypes

Vintages
Pre-1980
1980-2004
Post-2004 (New Construction)

Similar to the residential sector, the commercial building models were designed to provide an estimate of the hourly load profile for each commercial sub-sector and end-use combination (e.g., space heating end-use in offices sub-sector). This provided significantly more granularity than the hourly utility data was able to provide.

The first set of commercial load profiles generally had daily profiles with very high peak-to-trough ratios, representative of an individual commercial building facility with aggressive overnight setback. These profiles were not representative of the aggregate profile of an entire commercial building stock with varying schedules and occupancy patterns. Similar to the residential profiles, this “peakiness” was also not present in gate station data that was provided by the Gas Utilities. The following strategies were used to adjust the end-use load profiles to be more representative of the entire stock of commercial buildings in the Gas Utilities’ service territories:

- **Equipment schedules:** Equipment schedules for domestic hot water (DHW) consumption, kitchen equipment, and laundry equipment were examined for each building type and modified as necessary to ensure that the schedules were more representative of the building stock on average.
- **Setback schedule set-points:** Nighttime setbacks were found to be aggressive as a representation of the entire building stock. As such, nighttime setbacks were reduced and set-points were ramped up and down instead of being stepped up and down to better represent how the average setback temperature would vary from hour to hour across the entire building stock.
- **HVAC schedules:** The models were adjusted such that the HVAC system is available 24/7 instead of being completely shut down during unoccupied times. This had previously caused the nighttime space heating load to drop suddenly and dramatically and was not representative of the entire building stock. Together with the modifications for the thermostat setback, this helps to create a nighttime profile that averages out the impacts of buildings across the stock shutting down, setting back, or maintaining daytime set-points.
- **Infiltration schedules:** To better represent the diversity of the building stock and the varying ventilation schedules, infiltration schedules were ramped up and down rather than being stepped up and down.
- **Summer heating loads:** The building models included summer heating loads in other facility types as well. In reality, space heating systems may not even be available during the summer months (e.g., two-pipe system with space heating not available) and much of this potential heating would occur overnight, when facility managers are likely to let their space temperatures drift a bit lower. As such, space heating demand was manually removed during the summer months (i.e., mid-June to mid-September).

- **Summer reheat (hospitals):** For the Hospital building type, a very large degree of reheat was assumed during summer months and the models also assumed that all of the reheat was done via a gas boiler. Due to significant ventilation requirements in hospitals, this produced a much larger than anticipated summer heating load. The amount of reheat was scaled back to be more representative of the magnitude of reheat in hospitals and reflect the fact that a portion of this reheat is done via electric resistance duct heaters.
- **Food service end-use:** It was necessary to add a load profile for food service to a limited number of the U.S. DOE archetypes (i.e., offices and retail) since it was not already included. A modified version of the food service end-use load profile from the Quick Service archetype was used for this purpose.
- **Space heating schedules:** To account for the differing space heating schedules in the building stock and the diversity of the building stock in general, space heating load profiles were smoothed out.

Similar to the approach described with the residential sector building modeling and end-use load profiles, representative design day end-use load profiles for each of the commercial sub-sectors were generated by averaging the profiles of the 10 coldest weekdays and then scaling the space heating end-use load profiles to represent design day HDDs.

Industrial Sector

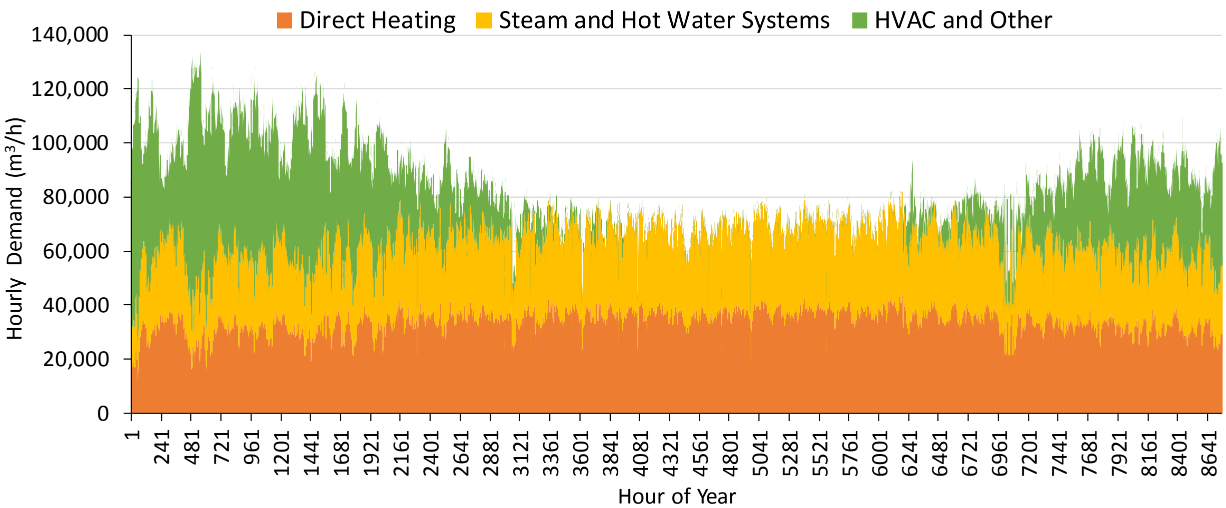
Three end-uses were considered for industrial sector:[94] 1) Direct heating; 2) Steam and Hot Water Systems; and 3) HVAC and Other. Unlike the residential and commercial sectors, no building modelling was done for the industrial sector. Instead, end-use load profiles were developed for each industrial sub-sector based on the 2014 industrial sector consumption data, as provided by the Gas Utilities. With the exception of the Greenhouses and Agriculture sub-sector, the end-use load profiles were developed according to the following methodology:

1. **Data cleaning and scaling:** The 2014 industrial consumption data was cleaned and scaled for each sub-sector, as described in Section 1.1.4.
2. **Annual end-use breakdown:** The annual consumption for each industrial sub-sector was broken down into annual end-use totals using the distribution of end-use consumption from the OEB CPS.
3. **Weather-dependent end-use:** The annual consumption for the HVAC and Other end-use was distributed on an hourly basis based on HDDs. However, since industrial buildings often have equipment that generates significant internal waste heating loads (e.g., motors, boilers, etc.), a 16ºC balance point temperature was employed for this step. It was also assumed that the buildings were not heated during summer months.
4. **Other end-uses:** The hourly HVAC and Other consumption was subtracted from total hourly consumption, and the remaining hourly consumption was apportioned based on the annual distribution of the remaining end-uses, as determined in step 2.

[94] As per the data the Gas Utilities provided for the OEB CPS and the analysis completed for that study, the industrial sector excludes certain rate classes ineligible for DSM. For example, Union Gas' Rates 25, 30, M10, T3, T9 are excluded from the industrial sector analysis.

Exhibit 22 shows the results of this methodology, as applied to the Manufacturing Facilities sub-sector for Union Gas' North region. Here, it can be observed that the non-HVAC end-uses remain fairly consistent throughout the entire year, while the HVAC and Other end-use is proportional to HDDs.

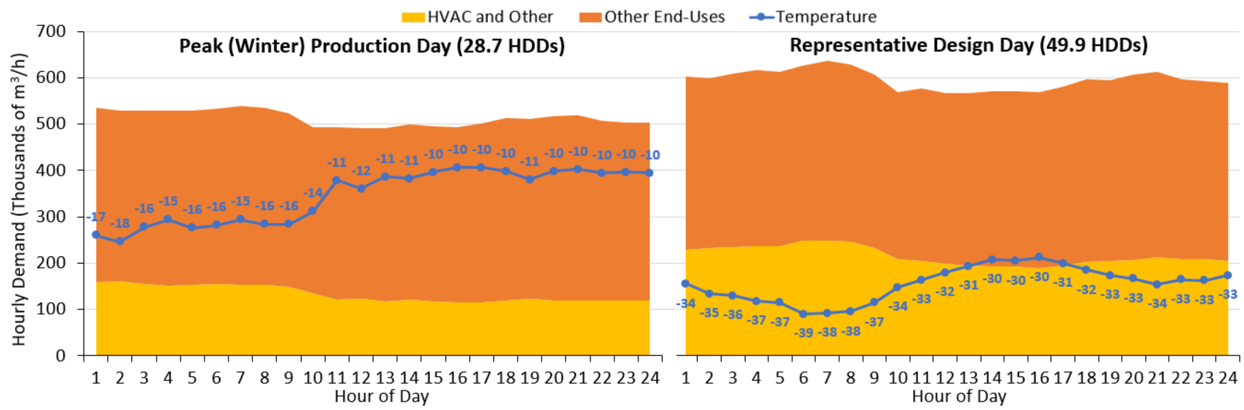
Exhibit 22: Example Industrial End-Use Load Profile (Manufacturing Facilities in Union Gas' North Region)



Because the Greenhouses and Agriculture sub-sector is unique in the industrial sector (dominated by space heating rather than other industrial processes), a separate methodology was used to develop the end-use load profiles for this sub-sector. The Greenhouses and Agriculture sub-sector has only two end-uses (HVAC and Other, Steam and Hot Water Systems), which are both used for space heating purposes (i.e., some greenhouses are heated with forced air unit heaters while others employ hydronic heating). Therefore, the end-use load profiles for this sub-sector were determined by distributing hourly demand based on the end-use split included in the OEB CPS.

The load profiles were relatively flat for most industrial sub-sectors, although it was noted that some variation occurs throughout the year due to changes in production. Since the utility peak design day (coldest day) could coincide with the industrial sector's peak production day, the industrial representative design day load profile was created by transposing the peak production day onto the utility peak design day, and scaling up the HVAC and Other end-use to meet the HDDs of the design day temperature profile. The results of this process are illustrated in Exhibit 23 for Union Gas' North region. The above process was also employed with each industrial sub-sector to create end-use load profiles that were representative of the design day in each service territory.

Exhibit 23: End-Use Load Profiles for Peak Winter Production Day and Representative Design Day for Union Gas' North Region



1.1.6 Macro Modeling and Calibration

For the next step in the peak demand savings analysis, ICF employed the base year (2014) annual consumption results from the OEB CPS to estimate peak demand contributions for each of the five peak periods. The modelling approach for this began with the load profiles that were developed for each sub-sector and end-use, as discussed in the previous section. The load profiles were used to develop hours-use factors, which essentially allow for the conversion of annual consumption values (m^3/yr.) to peak demand values for each of the peak periods being considered (i.e., m^3/h).

The following formula was used to develop the hours-use factors for peak periods #1-4 (i.e., morning lift period of 6-10 am during the coldest winter weekday) for each combination of sub-sector, end-use, and region:

$$\text{Hours-Use Factor (h)} = \frac{1}{(Hourly\ Demand)/(Annual\ Consumption)}$$

A similar approach was used to develop the hours-use Factors for peak period #5 (i.e., peak day, on average) for each combination of sub-sector, end-use, and region:

$$\text{Hours-Use Factor (h)} = \frac{24}{(Daily\ Demand)/(Annual\ Consumption)}$$

The appropriate hours-use factor was mapped to each respective subgrouping in the OEB CPS base year annual consumption results based upon the applicable end-use, sub-sector and region. The conversion between annual consumption and peak demand was then conducted using the following formula:

$$Peak\ Demand\ \left(\frac{m^3}{h}\right) = \frac{Base\ Year\ Consumption\ (m^3)}{Hours\text{-}Use\ Factor\ (h)}$$

For the residential and commercial sectors, the summation of the peak demand in each of the five peak periods was compared to appropriate hour from the representative design day load profile for each region. The approach to generate the representative design day load profile for each region based on utility hourly meter data is described in Section 2.1.4. The calibration process involved scaling the hours-use factors so that they would yield a peak demand consistent with the representative design day load profile.

Since the industrial sector analysis did not involve any building modeling (i.e., based on hourly meter data) and the industrial sector load profiles were scaled to match annual consumption from the OEB CPS, the hours-use factors for the industrial sector did not need to be calibrated.

1.2 Reference Case

This section details the approach that was used to develop the reference case peak period demand estimates for this study.

The reference case is a projection of natural gas consumption from 2015 to 2026 and includes natural conservation (which would already occur, even in the absence of DSM programs) but not the impacts of utility DSM programs. The reference case for the study is based on the 2014 base year and the Gas Utilities' long range volumetric gas forecasts.[95] It is the baseline against which the scenarios of energy savings are calculated.

1.2.1 OEB CPS Reference Case

The reference case includes the ongoing effects of DSM activity initiated before the OEB CPS study period (i.e., prior to 2016), and also includes the effects of DSM activity by other actors in the market, such as electricity utilities. The reference case also presents a scenario in which policy, legislation, and regulation continue to exist as they were at the time the OEB CPS study was completed. The inclusion of these first two areas of DSM activity into the reference case ensures that all natural conservation has been considered. Legislation that was not yet passed, or not clearly mapped out, was subject to influence and was therefore considered within the realm of potential savings. As such, the reference case provides the point of comparison for the calculation of new energy-saving opportunities associated with each of the scenarios that are assessed within this study.

Completion of the reference case portion of the OEB study involved the following steps:

- The detailed modelling input assumptions of new buildings (i.e., buildings expected to be constructed during the study period) were updated for each sub-sector in each service region. Changes in building envelope and equipment affecting energy consumption were noted
- The growth in building floor space was estimated for each sub-sector within each service region
- Naturally-occurring efficiency changes affecting annual natural gas use in existing buildings were estimated
- Special consideration was given to three factors:
  - Naturally-occurring improvements in equipment efficiency
  - Expected penetration of more efficient equipment into the building stock

[95] Although Union Gas provided a high-level total reference case consumption for the entire study period, the utility only forecasts for three years. As such, the consumption for the remaining years was based on an extrapolation of the near-term forecast.

    - Known, upcoming changes in building and equipment energy performance codes and standards
- Changes in natural gas share for each end-use were estimated
- The inputs from the preceding steps were entered into each sector model and estimates of natural gas use throughout the study period were generated
- For all sectors, the load growth was modelled based on the Gas Utilities' forecasts for each sector, excluding the effects of any discrete and incremental DSM efforts

Given the emergence of the cap and trade initiative since the OEB CPS was initiated, the carbon impacts were not included in the avoided costs analysis and therefore, a societal cost test (SCT) was not factored into the cost-benefit test. It was determined at the time that it would be best to defer consideration of the issue since final details related to the cap and trade initiative were not yet available to inform the analysis.

1.2.2 IRP Study Reference Case

The reference case analysis for this study leveraged the reference case results from the OEB CPS. As noted above, the OEB CPS accounted for growth in floor space and naturally-occurring efficiency changes affecting annual natural gas use in existing buildings and the model results were calibrated to utility forecasts of natural gas consumption. ICF recognizes that cap and trade activities can influence the IRP study reference case but there was still some uncertainty surrounding the impacts at the time of the OEB CPS. The load profiles and hours-use factors that were developed for the base year analysis were also employed for the IRP study reference case analysis. These values were deemed to be reasonable estimates for the reference case analysis as well since the reference case only includes natural efficiency changes. In addition, natural gas consumption profiles are highly dependent on factors such as weather and occupancy, which are not expected to change significantly over the 12-year study period (2014-2026). Furthermore, the factors used to calibrate the base year analysis were employed for the reference case analysis.

1.3 Achievable Potential

This section details the approach used to develop the results for the achievable potential scenario. The achievable potential analysis takes into account realistic market penetration rates of cost-effective measures over the study period based on a number of factors including market barriers, customer preference and acceptance based on payback periods, return on investment (ROI), investment hurdle rates, and other factors.

The following sections are included to describe the approach to developing the results for each of the efficiency scenarios:

- **OEB CPS Scenarios:** Provides some high-level insights into the approach that was used to generate the scenario results for the OEB CPS
- **IRP Study Scenarios:** Describes the scenarios that were employed in the IRP study
- **OEB CPS Measures:** Summary of the number of measures included in the OEB CPS and the parameters used to characterize the measures

- **IRP Study Measure Categorization:** Describes the approach used to characterize measures for this study and shows how the measures for each sector were categorized
- **Development of Non-Uniform Measure Savings Profiles:** Details the approach used to develop non-uniform measure savings profiles, with an emphasis on the approach used for adaptive thermostats and tankless water heaters
- **Macro Modeling:** Summarizes how the hours-use factors were leveraged to estimate peak demand impacts for the entire service territory

1.3.1 OEB CPS Scenarios

This section provides some high-level insights into the approach used to generate the scenario results for the OEB CPS.

Technical Potential

In the technical potential scenario, measures are applied regardless of how cost effective they are. The model used in the OEB CPS estimates measure savings by multiplying an end-use savings percentage by the average consumption for the end-use in a given building type (or plant type, depending on the sector). Therefore, three pieces of information are required to assess the technical potential savings: (i) the reference case end-use consumption; (ii) the reference case penetration; and (iii) the technically feasible penetration. It should also be noted that measures that are normally replaced at end of life, due mostly to economic considerations, are adopted at that rate, rather than assuming accelerated implementation. Measures that are not limited by equipment life are assumed to be adopted immediately.

As part of the OEB CPS, the ICF model uses what is referred to as cascading to account for interactive effects between measures. Cascading accounts for the fact that measures can be implemented in parallel (there are no interactive effects), in sequence (there are interactive effects), or can be mutually exclusive (only one measure or the other may be selected). Without cascading, the cumulative savings potential would be overestimated. Measures are generally included in the cascade in the following order: measures that reduce load (such as building envelope improvements), equipment measures, control measures, and behaviour measures.

Economic Potential

To develop the economic potential forecast, the following tasks were completed:

- The measure cost-effectiveness results for each of the energy-efficiency measures were reviewed
- Technology upgrades that were cost effective (i.e., greater than 1.0 benefit-cost ratio) were selected for inclusion either on a “full-cost” or “incremental” basis
  - Technical upgrades passing the measure TRC-plus test on a full-cost basis were implemented in the first year of the economic potential in which they passed the cost-effectiveness screen
  - Measures that only passed the cost-effectiveness screen on an incremental cost basis were introduced at the rate of equipment turn-over

The stream of future savings and costs was discounted using a real discount rate of 4%. Inflation was omitted from the analysis through the use of savings and costs that were expressed in constant 2014 dollars and a real discount rate.

The economic screen that was used in the OEB CPS was the TRC-plus cost-effectiveness test. The measure TRC-plus is a cost-benefit analysis of the net present value of energy savings that result from an investment in an efficiency or fuel choice technology or measure. The measure TRC-plus calculation considers a measure's full or incremental capital cost (depending on application) plus any change (positive or negative) in the combined annual energy and O&M costs.

Achievable Potential

The achievable potential estimates developed as part of the OEB CPS relied on interviews with market actors and estimates developed as part of previous research. Three achievable potential scenarios were modeled as part of the study:

- **Unconstrained achievable potential:** Natural gas savings achieved through efficiency improvements resulting from the most aggressive DSM programs, assuming no budget constraints or policy restrictions over the study period.
- **Constrained achievable potential:** Natural gas savings achieved through efficiency improvements resulting from programs at the DSM budget levels established by the OEB's 2015-2020 DSM Decision over the study period.
- **Semi-constrained achievable potential:** Natural gas savings achieved through efficiency improvements resulting from programs at DSM budget levels established by the OEB's decision on the DSM plans until 2017, then gradually increasing through 2018 and 2019 to twice the 2016 budget by 2020, and then staying at that level until the end of the study period.

1.3.2 IRP Study Scenarios

The scenarios included in the IRP study analysis are quite similar to the OEB CPS scenarios, including technical, economic, and achievable potentials. However, the following adjustments were made to the technical and achievable potential scenarios:

- **Technical potential:** Because the focus of the IRP study is to investigate the impacts of individual DSM measures on peak demand, it was important to compare the non-cascaded savings potential of individual measures. Therefore, a slight modification was made to the approach when comparing the technical savings potential of individual measures. Specifically, the non-cascaded savings potential was used for each measure and a scaling factor was applied across all measures to ensure that the total technical potential savings was equal to that of the cascaded approach. This adjustment ensures that the potential impact of each measure is considered on an even playing field, rather than being biased by its position in the cascading order. For example, it is expected that both an envelope upgrade and a furnace efficiency upgrade would have a significant impact on peak demand by reducing the space heating demand in a home; however, if cascaded potential savings were used, the furnace upgrade's impact on peak demand would be de-rated because it follows the envelope upgrade in the cascade order.

- **Achievable potential:** The IRP study leveraged the results of the OEB CPS constrained and unconstrained achievable potential scenarios. The constrained achievable potential is used for the analysis in this section, since this scenario most closely represents the savings potential based on current DSM spending levels. Therefore, all references to the achievable potential in Section IV refer to the constrained achievable potential. Conversely, the supply curves discussed in Section V makes use of the unconstrained achievable potential.

1.3.3 OEB CPS Measures

The final list of DSM measures for the OEB CPS included 52 residential measures, 59 commercial measures, and 57 industrial measures. A significant number of the measures were based on the Gas Utilities' input assumptions, which are filed annually. The list also includes DSM measures from ICF's database, which includes all measures ICF has included in previous natural gas conservation potential studies that are not in the Gas Utilities' filed input assumptions. In addition, the measure list includes some emerging DSM technologies. Although some measures are not explicitly included in utility DSM programs, they were included in the OEB CPS on the basis that they would be covered by the Gas Utilities' custom program offering and they are also part of the achievable potential savings.

Measure input assumptions and parameters include incremental costs, natural gas savings (m^3), other resource savings (other fuels and water), effective useful life, measure applicability, and classification into measure types. The measures are mapped to specific sectors, sub-sectors, and end-uses. In the case of weather-sensitive measures, ICF employed targeted building simulations to estimate savings.[96]

1.3.4 IRP Study Measure Categorization

The approach for deriving measure-level load profiles fell broadly into the following categories:

- **Uniform savings profile:** For many measures, based on ICF's experience and in consultation with the SAG and the Gas Utilities, it can be assumed that the savings profile matches the end-use profile to which it applies. For example, the distribution of energy savings resulting from a building envelope measure (e.g., attic insulation) would likely follow the space heating load profile. This type of measure was assigned a uniform savings profile (i.e., the savings profile uniformly maps to the end-use profile).
- **Non-uniform savings profile:** For some measures, such as controls measures, the measure savings were not uniformly distributed and it was necessary to develop estimates of how the measure savings were distributed. As such, it was necessary to develop custom load profiles for these measures.
- **No impact on peak demand:** Certain measures do not coincide with peak (i.e., none of the savings occur during the peak). At the extreme, this includes measures such as high-efficiency pool heaters for the residential sector. It was not necessary to develop a load profile for the savings from these measures.

[96] For example, ICF used HOT2000 to estimate the impact of some residential envelope measures, and used EnergyPlus for the same purpose in the commercial sector analysis.

The categorization of residential sector and commercial sector measures is summarized in Exhibit 24 and Exhibit 25 respectively.

Exhibit 24: Categorization of Residential Sector DSM Measures

Uniform Savings Profile		Non-Uniform Savings Profile
▪ 95% or Higher Efficiency Furnace ▪ Air Leakage Sealing and Insulation (Old Homes) ▪ Attic/Ceiling Insulation ▪ Basement Wall Insulation (R-12) ▪ Condensing Gas Boilers ▪ Condensing Gas Water Heaters ▪ Crawl space Insulation ▪ DHW Recirculation Systems (e.g. Metlund D'MAND®) ▪ DHW Tank Insulation ▪ Draft Proofing Kit ▪ Early Furnace Replacement - 60% AFUE - 90% AFUE Furnace ▪ Early Furnace Replacement - 70% AFUE - 90% AFUE Furnace ▪ Early Hot Water Heater Replacement (0.575 to 0.62 EF) ▪ Electric Ground-Source Heat Pumps ▪ ENERGY STAR for New Homes ▪ Faucet Aerator ▪ Heat Reflector Panels ▪ High-Efficiency Condensing Furnace ▪ High-Efficiency Gas Storage Water Heater	▪ High-Efficiency (ENERGY STAR) Clothes Washers ▪ High-Efficiency (ENERGY STAR) Dishwashers ▪ High-Efficiency Gas Clothes Dryers ▪ High-Efficiency Heat Recovery Ventilators (HRVs) ▪ Integrated Heating and DHW (Hydronic Heating) ▪ Low-Flow Shower Head ▪ Maintain Weatherstripping ▪ Minimize Hot and Warm Clothes Wash ▪ Net-Zero-Ready Home ▪ Pipe Wrap ▪ Professional Air Sealing/Weather Stripping/Caulking ▪ Reduce Temperature of DHW ▪ Slab Insulation (Unfinished Basements) ▪ Super High-Performance Windows ▪ Use Sensor for Clothes Dryer ▪ Wall Insulation ▪ Wastewater Heat Recovery Systems ▪ Zoned-Up Windows: (ENERGY STAR) Rating for a Colder Climate	▪ Active Solar Water Heating Systems ▪ Adaptive Thermostats ▪ Adaptive Thermostats - Direct Install ▪ Close Windows and Blinds ▪ Electric Air-Source Cold Climate Heat Pumps ▪ Fireplace intermittent ignition control retrofit ▪ High-Efficiency Fireplace with Pilotless Ignition ▪ Programmable Thermostat ▪ Social Benchmarking and Home Energy Monitoring ▪ Solar Preheated Make-Up Air Systems (e.g. SolarWall®) ▪ Tankless Water Heater ▪ Temperature Setback (During Day) ▪ Temperature Setback (Overnight) **No Peak Impact** ▪ Clothes lines and drying racks ▪ Insulating Pool Covers ▪ High-Efficiency Gas-Fired Pool Heaters ▪ Solar Pool Heaters

Exhibit 25: Categorization of Commercial Sector DSM Measures

Uniform Savings Profile		Non-Uniform Savings Profile
▪ Boilers - Advanced Controls ▪ Boilers - Blowdown Heat Recovery ▪ Boilers - Combustion Air Preheat ▪ Boilers - Feedwater Economizers ▪ Boilers – High-Efficiency Burners ▪ CEE Tier 2 Clothes Washers ▪ Commercial Ozone Laundry Treatment ▪ Condensing Boilers ▪ Condensing Make-Up Air Units ▪ Condensing Storage Water Heaters ▪ Condensing Unit Heaters ▪ Destratification Fans ▪ Drain Water Heat Recovery (DWHR) ▪ Energy Recovery Ventilation ▪ Energy Recovery Ventilation (Enhanced) ▪ ENERGY STAR Clothes Washers	▪ ENERGY STAR Dishwashers ▪ ENERGY STAR Fryers ▪ ENERGY STAR Steam Cookers ▪ Faucet Aerators ▪ Gas-Fired Heat Pumps ▪ Gas-Fired Rooftop Units (Two-Stage) ▪ Green Roofs ▪ Heat Recovery Ventilation ▪ Heat Reflector Panels ▪ High-Efficiency Boilers ▪ High-Efficiency Underfired Broilers ▪ High-Performance Glazing ▪ Indirect Water Heaters ▪ Infrared Heaters ▪ Low-Flow Showerheads ▪ Roof Insulation ▪ Super High-Efficiency Furnaces ▪ Wall Insulation	▪ Adaptive Thermostats ▪ Advanced BAS/Controllers ▪ Air Curtains ▪ Building Recommissioning (Enhanced) ▪ Building Recommissioning (Standard) ▪ Condensing Tankless Water Heaters ▪ Demand Control Kitchen Ventilation ▪ Demand Control Ventilation ▪ Demand Control Ventilation (Enhanced) ▪ Electric Air-Source Cold Climate Heat Pumps ▪ Keep Doors Closed ▪ New Construction - 25% Better ▪ New Construction - 40% Better ▪ O&M Improvements ▪ Refrigeration Waste Heat Recovery ▪ Solar Preheat Make-up Air ▪ Solar Water Preheat (DHW) ▪ Use Shades/Blinds ▪ Ventilation Fan VFDs

Measures can also be categorized based on their impact on peak demand. When considering the impacts to peak hour, the measures can either have a positive impact on peak demand (peak period demand savings), a negative impact on peak demand (peak period demand increases), or no impact on peak demand. These three categories are explained below:

- **Peak reduction:** The vast majority of measures reduce peak demand since at least a portion of their savings coincide with the peak.
- **No impact on peak:** As noted above, some measures do not coincide with peak (i.e., no savings occur during the peak demand period). One example of such a measure is a high-efficiency pool heater applied to an outdoor pool.
- **Peak increase:** The savings from a small number of measures, such as adaptive/smart thermostats, do not coincide with peak. Furthermore, these measures were found to actually increase energy consumption during certain peak hours. It should be noted, however, that these measures still provide energy savings when the peak day is considered in aggregate, and may still provide demand savings during hours surrounding the peak hour.[97]

All industrial sector DSM measures were included in the uniform savings profile category since there is no clear pattern to when the measure savings would occur, both within an individual

[97] Adaptive/smart thermostats are also an example of a measure that could be utilized within the context of a demand response program to reduce peak hour demand over the morning lift period.

facility or between industrial facilities. Industrial facilities also tend to operate on an extended schedule, so occupancy plays a less significant role on energy consumption. As a result, the industrial sector end-use load profiles developed as part of the base year analysis were used to estimate the distribution of all industrial sector measure savings. The list of industrial sector measures is summarized in Exhibit 26.

Exhibit 26: Categorization of Industrial Sector DSM Measures

Uniform Savings Profile

- Advanced Boiler Controls
- Advanced Heating and Process Controls
- Air Compressor Heat Recovery
- Asphalt and Cement Manufacturing Process Improvements
- Automated Blowdown Control
- Automated Temperature Control
- Blowdown Heat Recovery
- Boiler Combustion Air Preheat
- Boiler Right Sizing and Load Management
- Boiler Tune Up
- Burn Digester Gas in Boilers
- Chemical Manufacturing Process Improvements
- Condensate Return
- Condensing Boiler
- Condensing Economizers
- Destratification Fans
- Direct Contact Water Heaters
- Exhaust Gas Heat Recovery
- Fabricated Metal Manufacturing Process Improvements
- Feedwater Economizers
- Food and Beverage Manufacturing Process Improvements
- Greenhouse Curtains
- Greenhouse Envelope Improvements
- Greenhouses Other Energy-Efficiency Upgrades
- High-Efficiency Burners
- High-Efficiency Furnaces
- High-Efficiency Heating Units
- High-Efficiency Ovens & Dryers
- Improved Building Envelope
- Insulation
- Minimize Deaerator Vent Losses
- Minimize Door Openings
- Mining Process Improvements
- Non-Metallic Mineral Product Manufacturing Process Improvements
- Optimize Combustion
- Primary Metal Manufacturing Process Improvements
- Process Heat Recovery
- Process Improvements (changing cleaning chemicals, setpoints, exhaust, moisture control, etc.)
- Pulp and Paper Process Improvements
- Radiant Heaters
- Reduce Boiler Steam Pressure
- Reduced Furnace Openings (air & chain curtains)
- Refining Process Improvements
- Regenerative Thermal Oxidizers
- Solar Walls
- Steam Leak Repairs
- Steam Trap Survey and Repair
- Transportation and Machinery Manufacturing Process Improvements
- Ventilation Heat Recovery
- Ventilation Optimization
- Warehouse Loading Dock Seals

1.3.5 Development of Non-Uniform Measure Savings Profiles

Although a significant number of DSM measures were deemed to have non-uniform measure savings profiles, the majority were still linked to the distribution of annual gas consumption, as estimated by the end-use load profiles developed for the base year analysis. For example, although space heating controls measures tend to provide more peak period demand savings during unoccupied periods, they still provide a greater proportion of peak period demand savings during colder, unoccupied periods. As such, the approach to developing non-uniform measure savings profiles leveraged the end-use load profiles developed for the base year analysis as a starting point. Next, scaling curves were applied to scale the end-use load profiles for each of the sub-sectors on a weekday, weekend, and monthly basis.

In many cases, the profiles of these scaling curves were tied to occupancy schedules for each of the sub-sectors. For example, Exhibit 27 shows the scaling curve applied to the space heating end-use load profile to estimate the distribution of peak period demand savings for the recommissioning (RCx) measure in offices. The scaling curve for the RCx measures load profile assumes an inverse relationship with occupancy since many of the measures typically implemented as part of RCx result in savings during unoccupied periods. Essentially, the annual end-use load profile for space heating in offices, which was developed as part of the base year analysis, was multiplied by the factors in this exhibit to estimate the distribution of savings. An example of the resulting load profile for the RCx measure is shown in Exhibit 28, which shows that peak period demand savings are maximized during cold periods when the space is unoccupied.

Exhibit 27: Scaling Curve Applied to Office Space Heating Load Profile to Estimate Annual Distribution of Recommissioning Savings in Offices

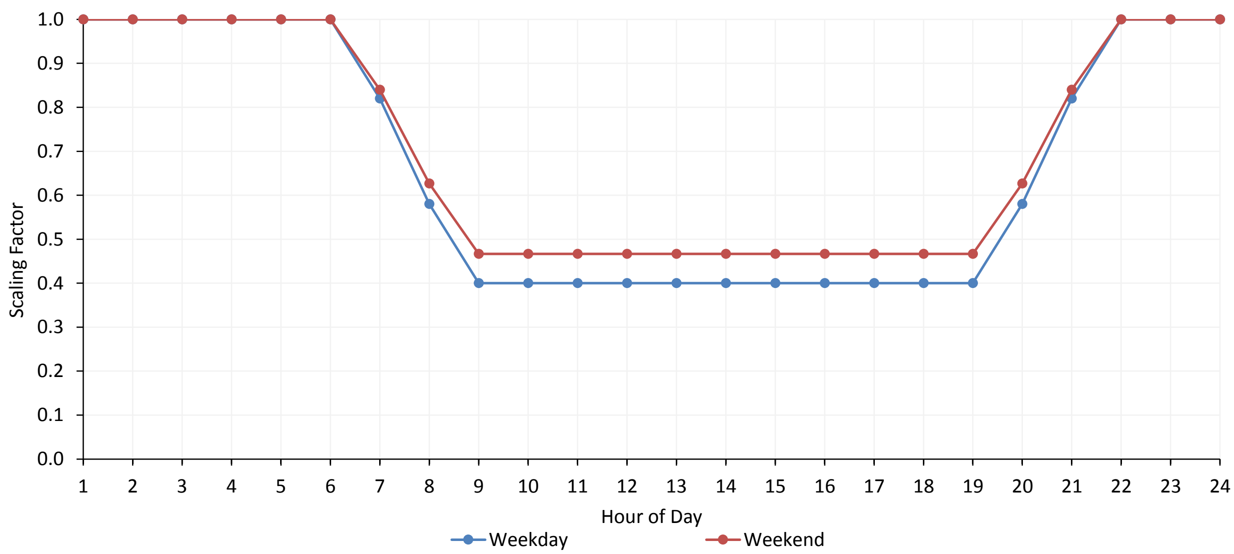
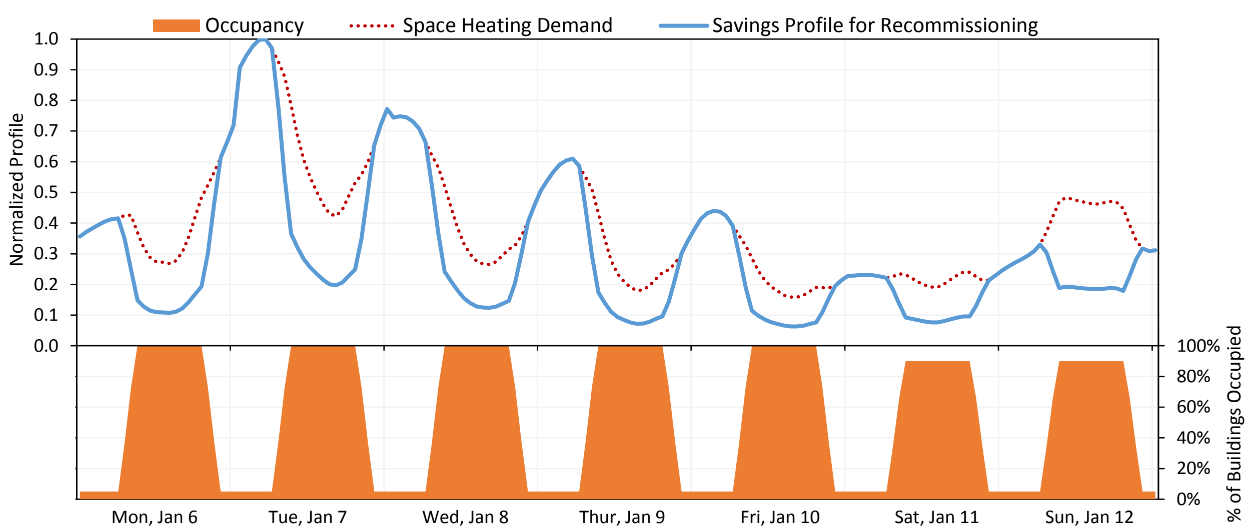
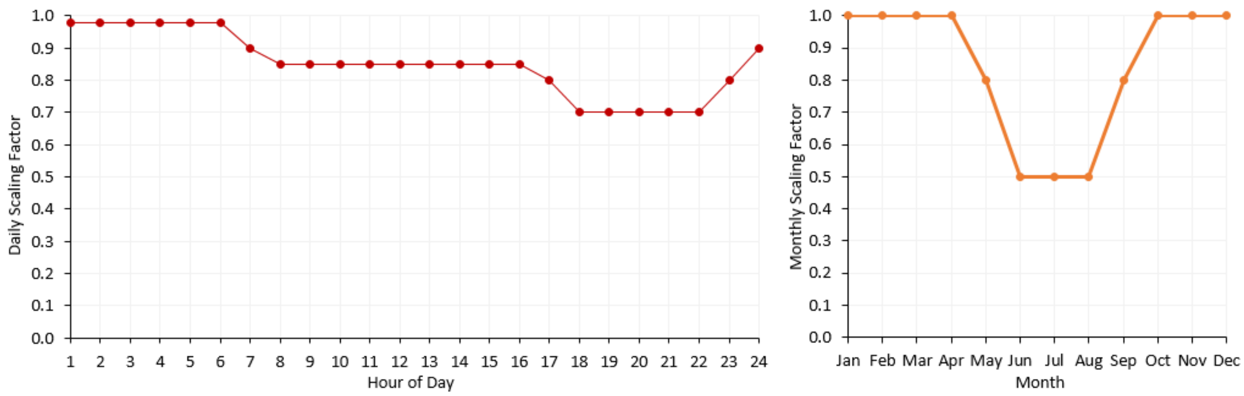


Exhibit 28: Measure Load Profile for Recommissioning in Office Buildings



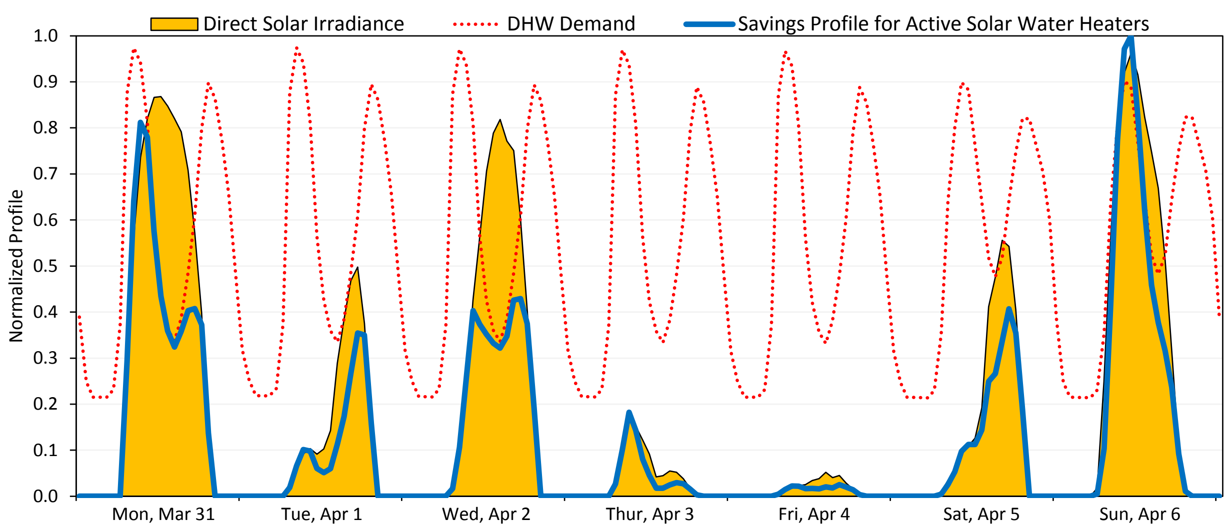
For a select few measures, custom scaling curves were developed to estimate the distribution of the measure savings. For example, fireplace measures applied to the residential sector required the development of custom scaling curves, which were based on estimates of when an average fireplace is used and when pilot lights are burning. These estimates were informed by a detailed technology assessment study that ICF completed on behalf of FortisBC and which was focused on higher efficiency fireplace options.[98]

Exhibit 29: Scaling Curves Applied to Residential Space Heating Load Profile to Estimate Annual Distribution of Savings from Fireplace Intermittent Ignition Control Retrofit



There were also a select number of solar energy measures for which custom profiles were developed. The distribution of energy savings from these measures was linked to a combination of solar irradiance and end-use load profiles. For example, Exhibit 30 demonstrates how the savings profile for active solar water heaters is maximized when DHW demand and solar irradiance occur simultaneously.

Exhibit 30: Savings Profile for Residential Active Solar Water Heaters



The development of the measure load profiles for adaptive thermostats and tankless water heaters was more involved. As such, the process is described in the following sections.

98 ICF, *Pre-Feasibility Study: Upgrades for Decorative Fireplaces*, completed on behalf of FortisBC, Feb. 14, 2014

Adaptive Thermostats

Adaptive thermostats are a subset of programmable thermostats with advanced functionality. They are referred to by many names, including smart thermostats, learning thermostats, and web-enabled communicating thermostats. Adaptive thermostats can be applied in both residential and commercial sector facilities. Some popular options of residential-grade and commercial-grade adaptive thermostats are shown in Exhibit 31 and Exhibit 32, respectively. In most applications, adaptive thermostats enable an increased amount of temperature setback, resulting in space heating savings. This is enhanced by the fact that most residential-grade and some commercial-grade adaptive thermostats also include some type of occupancy sensing capability, allowing them to detect unoccupied periods and automatically setback temperatures.

Exhibit 31: Residential-Grade Adaptive Thermostat Offerings from Nest, ecobee (ecobee3), and Honeywell (Honeywell Lyric Round)[99]

Exhibit 32: Commercial-Grade Adaptive Thermostat Offerings from Carrier (Carrier Connect 33CONNECTSTAT)[100] and ecobee (ecobee EMS Si)[101]

[99] How-To-Geek, *Nest vs. ecobee3 vs. Honeywell Lyric: Which Smart Thermostat Should You Buy?*, http://www.howtogeek.com/259644/nest-vs.-ecobee3-vs.-honeywell-lyric-which-smart-thermostat-should-you-buy/
[100] Carrier. *Wi-Fi Commercial Thermostat 33CONNECTSTAT*. http://www.utcccs-cdn.com/hvac/docs/1000/Public/09/11-808-570-01_hi.pdf
[101] ecobee, *Smart Si User Manual*. https://www.ecobee.com/wp-content/uploads/2014/05/ecobeeSmartSi_User_Manual.pdf

Although adaptive thermostats can provide significant annual gas savings, they can lead to periods of increased demand because gas-fired HVAC systems often need to work harder and/or run for extended periods of time to recover from temperature setbacks. To assess the potential peak period demand impacts of adaptive thermostats in residential and commercial applications, it was necessary to estimate standard and setback temperature schedules of different types of buildings. EnergyPlus was then used to estimate and compare the hourly energy consumption of standard buildings to buildings with adaptive thermostats. More details on this approach are provided in the following subsections.

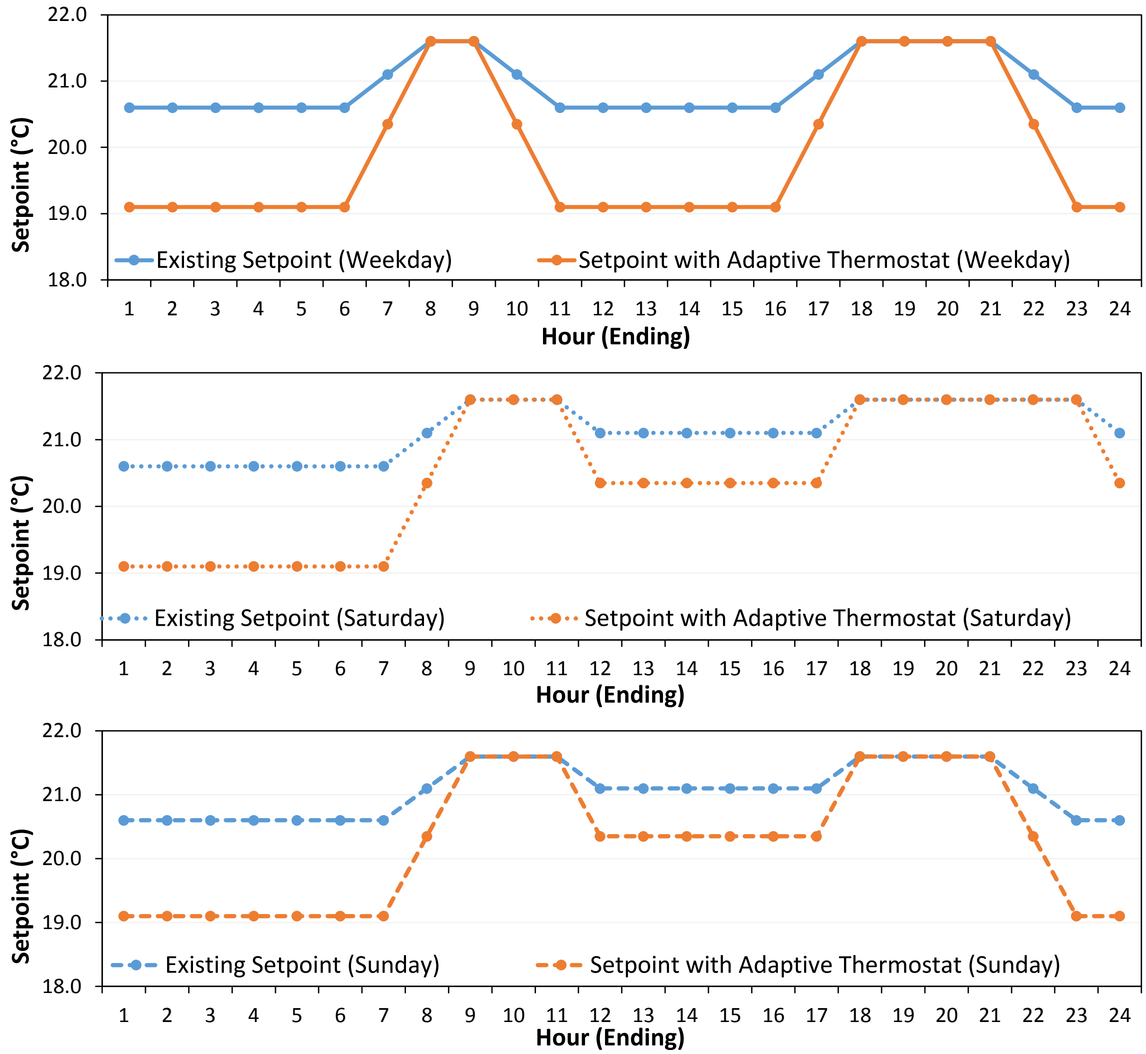
Residential Temperature Schedules

Residential temperature setpoint schedules were estimated by ICF based on typical home occupancy patterns. Opportunities for residential temperature setback are usually centred around overnight periods and during the day, when occupants are at work; there are also opportunities for temperature setback during weekends. The baseline (existing setpoint) schedules include some temperature setback since a proportion of homeowners either setback their temperatures manually or employ a standard programmable thermostat effectively.

A recent white paper by Nest suggests that average nighttime setback for its customers ranges from 2.2-2.7ºC (4.0-4.9ºF).[102] CMHC suggests that a temperature setback of 2.0ºC leads to some demand savings and little risk, while a temperature setback of 4-6ºC can potentially create comfort and moisture issues. As such, a temperature setback in the range of 2.5ºC is reasonable and representative in most residential applications. Since the baseline temperature schedules include a 1.0ºC setback, a 1.5ºC increment was applied to the adaptive thermostat schedules. The resulting temperature schedule for homes is depicted in Exhibit 33. Differing temperature setpoint schedules were derived for weekdays, Saturdays, and Sundays.

[102] Nest Labs, *White Paper - Energy Savings from the Nest Learning Thermostat: Energy Bill Analysis Results*, p. 9, Feb. 2015. https://nest.com/downloads/press/documents/energy-savings-white-paper.pdf

Exhibit 33: Representative Temperature Setpoint Schedule for Residential Sector



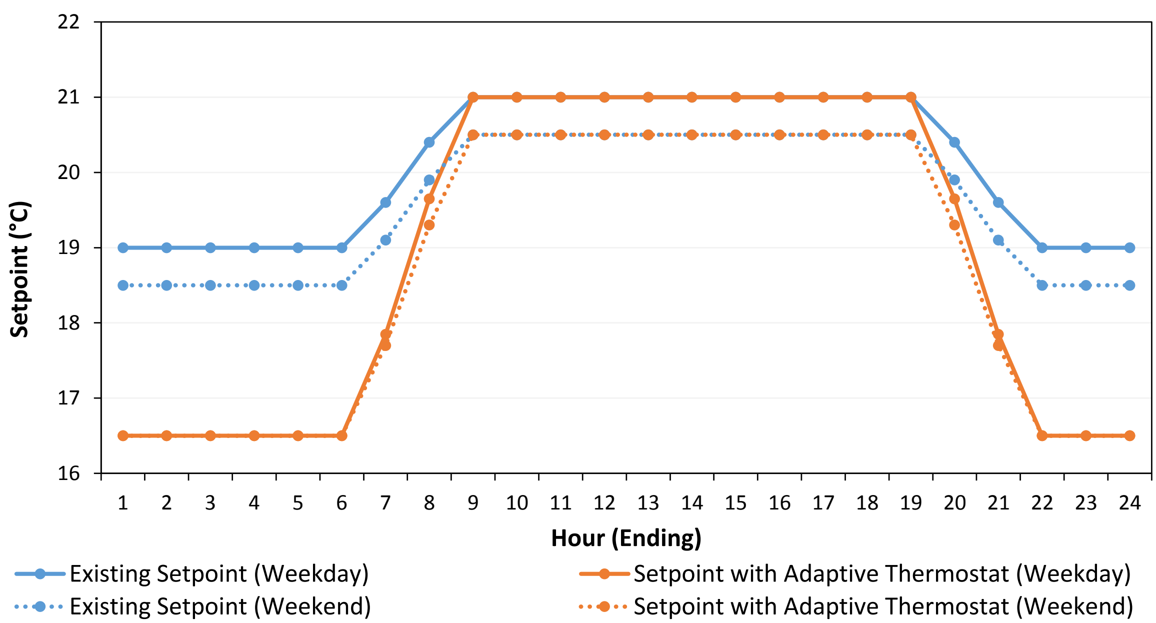
Commercial Temperature Schedules

Temperature setpoint schedules for each of the commercial sub-sectors were developed starting from the schedules included in the U.S. DOE commercial reference building archetype models. As noted in the load profiles section of the base year approach (Section 1.1), these temperature setpoint schedules were modified to ensure they are more representative of the building stock.

Incremental temperature setback was added to the baseline temperature setpoint schedules to reflect the implementation of adaptive thermostats. The amount of additional setback was varied by commercial building type based on the estimated potential for incremental setback during unoccupied periods. Factors such as the existing proportion of buildings that sets its temperatures back during unoccupied periods, and the variability in occupancy schedules were considered. For example, in certain sub-sectors like office, retail, restaurants, and schools, occupancy tends to be more binary (e.g., buildings are fully unoccupied overnight) and there is more potential for additional temperature setback. In other space types, such as hotel common areas and hospitals, additional setback during unoccupied periods can be more challenging to implement.

As an example, the resulting temperature setpoint schedule for the office sub-sector is depicted in Exhibit 34. Separate temperature schedules were developed for weekdays and weekends since this was an important consideration for many of the commercial building types. Incremental setback due to the implementation of adaptive thermostats was estimated at 2.5° C during weekdays and 2.0° C during weekends.

Exhibit 34: Representative Temperature Setpoint Schedule for Offices

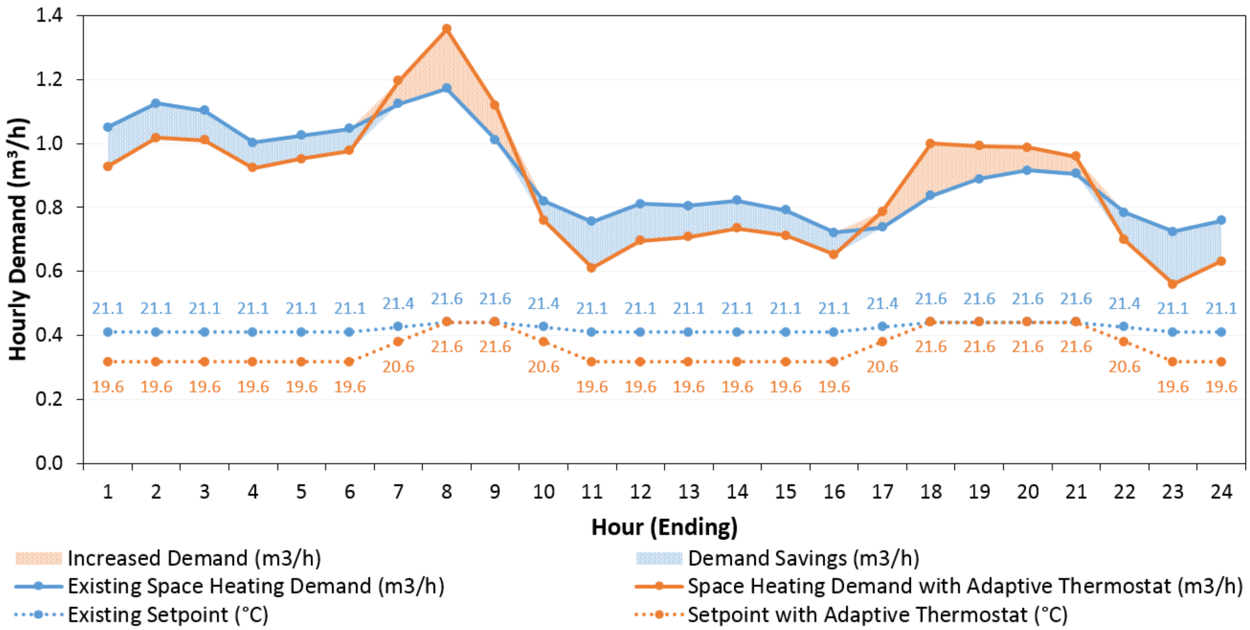


Modeling Approach and Results

The building models, constructed as part of the development of end-use load profiles for the base year analysis, were used to investigate the impacts of adaptive thermostats. The temperature schedules for buildings with adaptive thermostats were applied to the models, and updated space heating end-use load profiles were generated based on the modeling results. By subtracting the space heating profiles for the adaptive thermostat profiles from the baseline profiles, savings profiles were developed for the adaptive thermostat measure. Much like the approach employed for the base year analysis, these hourly measure savings profiles were used to develop hours-use factors that represent the conversion between annual consumption savings and peak demand impacts.

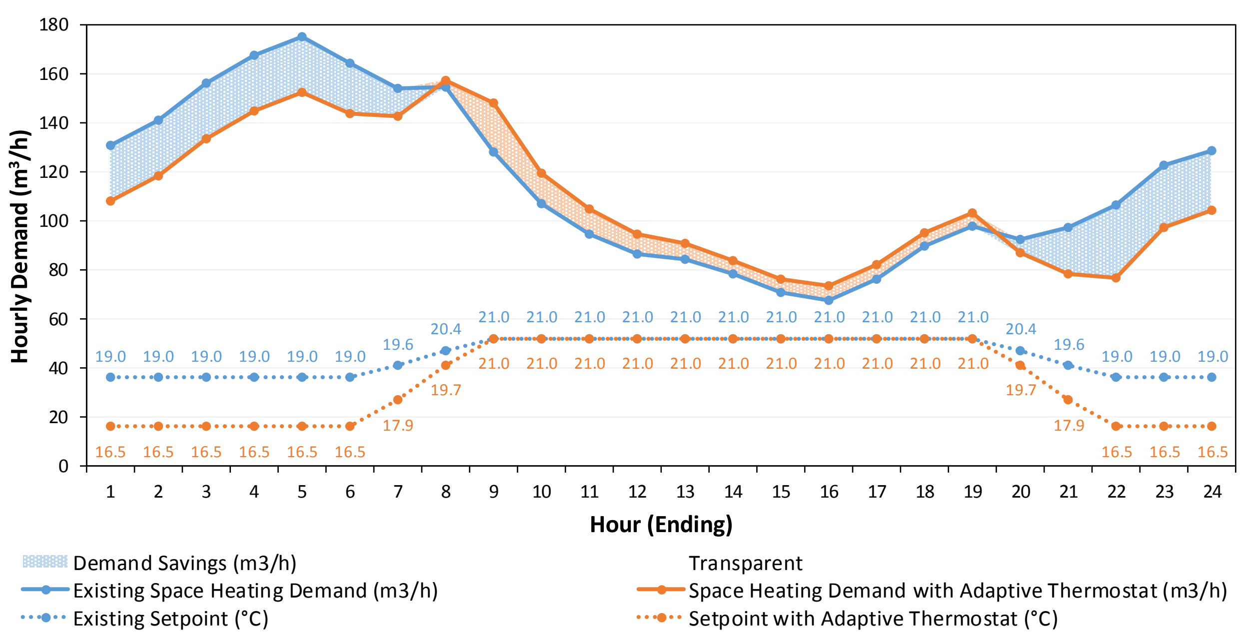
Exhibit 35 presents an example of the modeling results for the residential sector. Periods when the space heating system is recovering from a temperature setback, and which results in increased gas demand are shown in the orange coloured areas.

Exhibit 35: Residential Sector Hourly Demand Comparison for Adaptive Thermostats



Similar results were obtained for commercial sector buildings. For example, Exhibit 36 presents the space heating load profiles for offices. Although the temperature setpoint schedules applied via the adaptive thermostats clearly result in significant overall savings (shown in the blue coloured areas), there are periods where the demand for the space heating system is higher than the baseline scenario with minimal temperature setback (shown in the orange coloured areas).

Exhibit 36: Hourly Demand Comparison for Adaptive Thermostats Applied to Offices

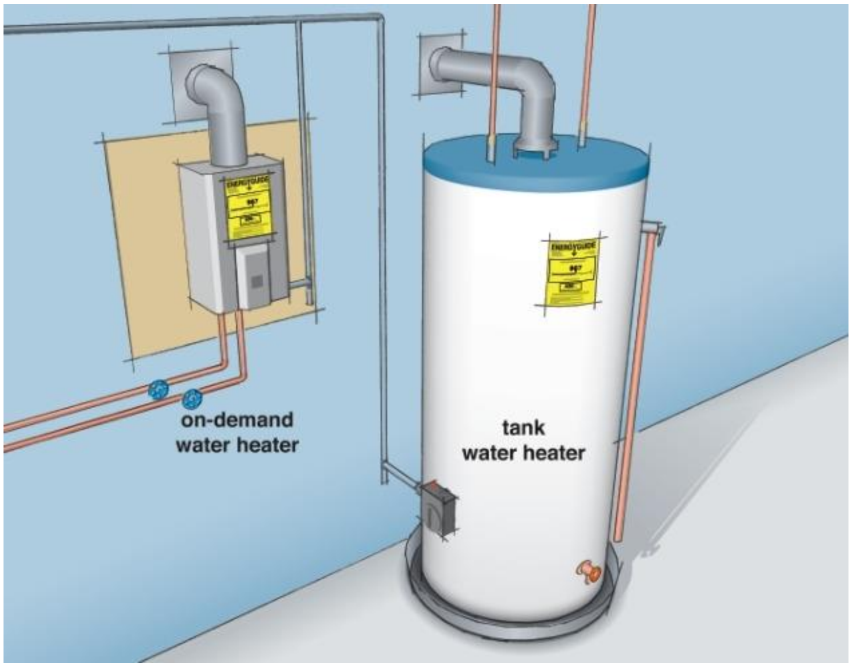


ICF carried out additional analysis to investigate the cause of the protracted increase in space heating consumption following recoveries from a temperature setback. This effect was present in all modelling results, although the magnitude of the impact differed between the various residential and commercial building types. ICF's investigation indicated that the effect was due to the building's thermal mass (i.e., thermal mass of building frame and contents). While the indoor air can be heated relatively quickly on a very cold winter day, it can take substantially longer to fully heat up the building frame and contents. During this period, the building's thermal mass "leaches" heat from the conditioned air and the building's HVAC system must work slightly harder to make up for the deficit. ICF concluded that the variance in the magnitude across different types of buildings is due to different types of building construction.

Tankless Water Heaters

Tankless water heaters (TWHs), also referred to as on-demand, point-of-use, or instantaneous water heaters, heat water on demand and have no storage tank. Installing TWHs instead of typical storage tank water heaters can result in significant annual gas savings. As illustrated in Exhibit 37, this is mainly due to the elimination of hot water storage tanks and their associated losses. As a result, even non-condensing TWHs are often rated at an energy factor (EF) greater than 0.80.[103] This compares with rated energy factors in the range of 0.60 for most storage tank water heaters.

Exhibit 37: Graphical Representation of a Tankless Water Heater and a Tank Water Heater[104]



[103] EF is used to rate the efficiency of water heaters. A water heater's EF is determined based on laboratory testing, assuming a standard hot water use profile with fixed inlet and outlet water temperatures. The testing accounts for standby losses and the operating efficiency of the water heater.
[104] U.S. DOE, *Estimating Costs and Efficiency of Storage, Demand, and Heat Pump Water Heaters.* https://energy.gov/energysaver/estimating-costs-and-efficiency-storage-demand-and-heat-pump-water-heaters

Since TWHs must heat water on demand and cannot rely on stored hot water to buffer that demand, they typically incorporate a much higher capacity burner. As such, while residential tank water heaters are typically rated at an input capacity of about 40,000 BTU/h, residential TWHs are often rated at about 180,000 BTU/h. Despite the significant annual savings, this suggests that there are potential demand increase implications resulting from the installation of TWHs.

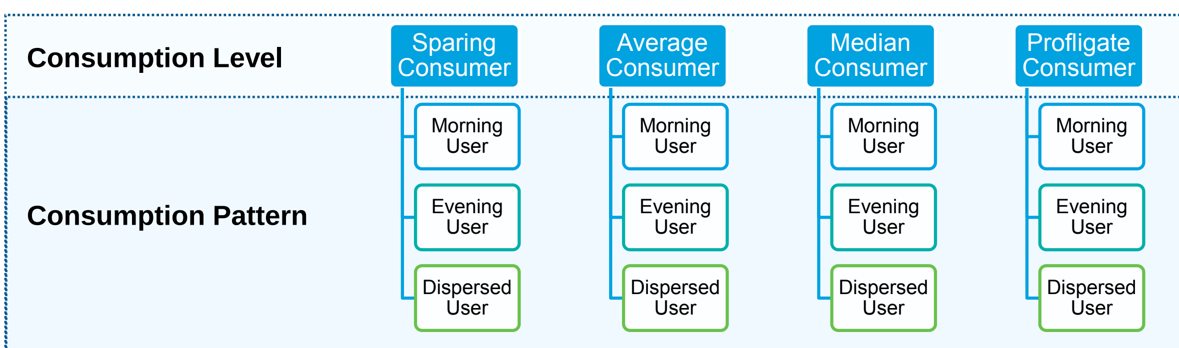
To assess the potential demand impacts of TWHs, the IRP study sought to understand typical hot water usage profiles and the real-world energy use of water heaters. Modeling was then carried out in EnergyPlus to estimate and compare the hourly energy consumption of TWHs and tank water heaters. Each of these items are discussed in detail in the following subsections.

Residential Hot Water Usage Profiles

Hot water usage profiles vary significantly, both between homes and on a day-to-day basis for any individual home. Although metered hot water consumption data is limited, ICF identified two relevant sources that could act as representative data for the purposes of the IRP study. Both sources are based on measurements of hot water consumption in homes in Quebec. The most detailed and relevant source developed representative hot water draw profiles based on measurements of 73 homes in Quebec.[105] This dataset includes a total of 12 representative profiles, representing four hot water consumption levels and three consumption patterns. The categories included in this data are summarized in Exhibit 38.

Among other uses, this data was employed to experimentally validate a water heater simulation model, which was in turn used to investigate peak demand shifting control strategies for electric water heaters. The time resolution of the data was five minutes, allowing for the demand impacts of relatively short periods of hot water consumption to be modeled.

Exhibit 38: Overview of Categories Included in Hot Water Consumption Data[105]



[105] Edwards, S. et al., *Representative Hot Water Draw Profiles at High Temporal Resolution for Simulating the Performance of Solar Thermal Systems*, Solar Energy (111) p. 43-52, 2015. https://carleton.ca/sbes/publications/hot-water-demand-profiles-downloadable/

Measured Savings and Energy Factors

As noted above, energy factor (EF) is used to characterize the efficiency of water heaters. However, several studies, including a study conducted on behalf of the Minnesota Office of Energy Security, found significant differences between the efficiency of water heaters in real-world situations compared with their rated efficiencies, which are based on standardized laboratory testing.[106] Examples of real-world considerations that impact the efficiency of water heaters include:

- **Draw patterns:** Rather than the small number of large hot water draws that EF testing is based on, measurements of hot water consumption suggest that a large number of small draws are much more common.
- **Tankless water heater heat exchangers:** Although TWHs do not have continuous stand-by losses associated with a storage tank, the heat exchangers must be brought up to temperature before delivering hot water. This has an impact on both the efficiency of TWHs and the hot water delivery time, especially with short draws.

The Minnesota study installed and metered a total of 26 water heaters in 10 homes, with an average of 363 days of usable data collected at each home. This included eight storage water heaters, 10 non-condensing TWHs, and eight condensing TWHs. To improve data quality, two water heaters were installed in each home at any given time, allowing for each site to alternate its use of a water heater on a monthly basis.

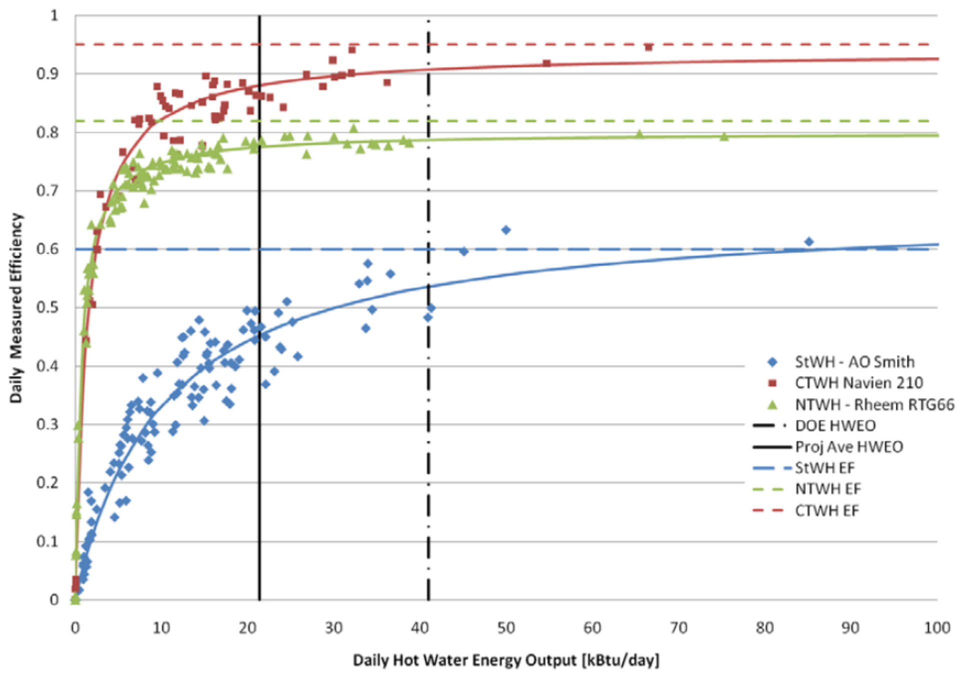
The results of the study indicate that TWHs result in average gas consumption savings of 36%. In addition, despite the incremental 9% difference in EF ratings for condensing TWHs, the average savings relative to tank water heaters was found to be 39%. Furthermore, the study found the following discrepancies between measured annual efficiency and rated EF:

- **Storage water heaters:** On average, actual efficiency averaged 23% less than rated EF
- **Tankless water heaters:** On average, actual efficiency averaged 10% less than rated EF
- **Condensing TWHs:** On average, actual efficiency averaged 10% less than rated EF

However, as shown in Exhibit 39, the Minnesota study also found that the actual efficiency of water heaters approaches the rated EF as hot water consumption increases.

[106] Center for Energy and Environment, *Actual Savings and Performance of Natural Gas Tankless Water Heaters*, prepared for Minnesota Office of Energy Security, Aug. 30, 2010

Exhibit 39: Measured Efficiencies for Three Water Heaters at a Single Site[107]



Modeling Approach and Results

The Minnesota study also investigated the impact of TWHs on whole home natural gas demand. Average demand was assessed at five-minute increments and periods where storage water heaters were active were compared with those where TWHs were active. Although the peak demand impacts analysis was not the primary focus of the study, and its assessment in this area was limited to the impact on whole home natural gas consumption (which included other gas-fired equipment, such as gas furnaces), the study concluded that "morning peaks are similar in duration and magnitude regardless of which water heater is being used."

To verify the Minnesota study results, ICF used EnergyPlus to model water heater energy consumption. This modeling leveraged the estimates of actual water heater efficiencies from the Minnesota study and was based on the five-minute interval data noted above. ICF used the hot water consumption data from the profligate user (high usage) categories to ensure that the analysis was conservative. Using this portion of the dataset results in a more conservative analysis since any increases in peak hour demand due to TWHs are most likely to occur in homes with higher hot water consumption (i.e., in general, homes with higher occupancy).

The other challenge was to ensure that the analysis adequately represented a community of homes with diverse hot water usage patterns. This was accomplished by treating each winter weekday as a distinct hot water usage profile that could be used to represent a separate home on any given winter day. By overlaying all of the weekday data for each profligate user type (i.e., morning, evening, and distributed) in January and February, this approach was used to represent a community of 129 homes with high water usage patterns.

[107] Center for Energy and Environment, *Actual Savings and Performance of Natural Gas Tankless Water Heaters*, prepared for Minnesota Office of Energy Security, Aug. 30, 2010

The results of this modeling are summarized in Exhibit 40 and Exhibit 41, which show the load profile for the entire day. The first exhibit presents the results at a five-minute resolution, demonstrating that even at this resolution the peak hour demand requirements rarely exceed those of the baseline storage water heaters. Exhibit 41 shows the same results at a one-hour resolution. It is important to consider the results at a one-hour resolution since the IRP study is assessing demand impacts at that time interval. This exhibit demonstrates that at a one-hour resolution the demand requirements for the TWHs are consistently below those of the storage water heaters. In fact, for the majority of the day, reduction in demand is consistent with what would be expected from the difference in the EF of the noted equipment.

Exhibit 40: Tankless Water Heater Modeling Results – *Simulated High-Use Community, 5-Minute Resolution*

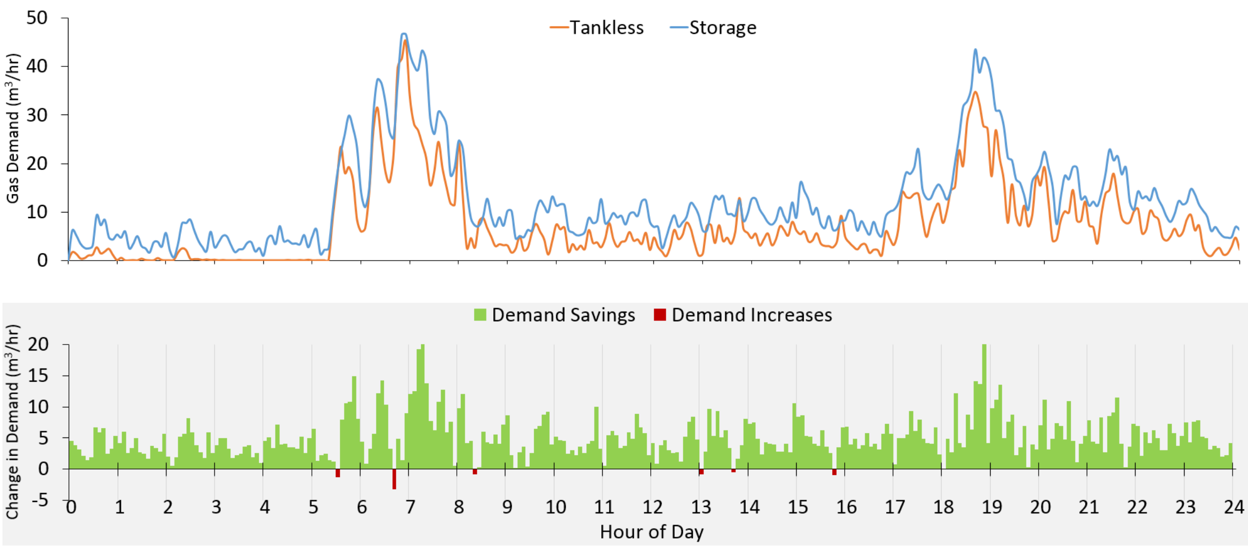
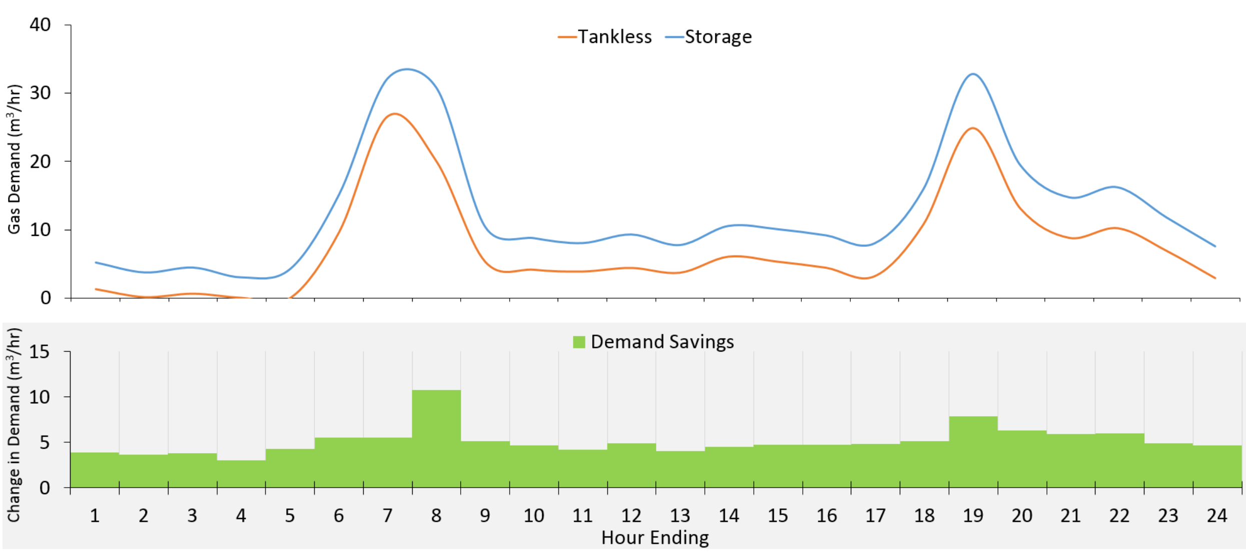


Exhibit 41: Tankless Water Heater Modeling Results – *Simulated High-Use Community, 1-Hour Resolution*



It is important to note that additional research and in-situ metering is required to validate ICF's modeling results. However, ICF's analysis of the different types of hot water draw profiles and consumption patterns suggests that natural gas peak hour demand from TWHs does not typically surpass the peak hour demand from storage water heaters when one-hour increments are considered. The community profile included in Exhibit 42 was assumed to representative of the hot water demand for the entire building stock. As such, this community profile was used to develop the hours-use factors for the tankless water heater measure.

1.3.6 Macro Modeling

The peak demand impact analysis for the scenarios employed the annual measure savings results from the OEB CPS to estimate peak demand contributions. The measure savings load profiles that were developed for each measure, as discussed in the previous section, were also an important input into this portion of the analysis since they provided an estimate of the distribution of the measure savings throughout the year. The savings profiles were used to develop hours-use factors, which essentially allow for the conversion of annual measure savings (m^3/yr.) to peak demand savings values for each of the five peak periods being considered (i.e., m^3/h).

The following formula was used to develop the hours-use factors for peak periods #1-4 (i.e., morning lift period of 6-10 a.m. during the coldest winter weekday) for each measure:

$$\text{Hours-Use Factor (h)} = \frac{1}{(Hourly\ Savings)/(Annual\ Savings)}$$

In some cases, the hourly savings were negative, indicating that the measure resulted in an increase in peak demand for the hour in question. This resulted in negative hours-use factors, which also suggested peak demand increases.

A similar approach was used to develop the hours-use factors for peak period #5 (i.e., peak day, on average) for each combination of sub-sector, end-use, and region:

$$\text{Hours-Use Factor (h)} = \frac{24}{(Daily\ Savings)/(Annual\ Savings)}$$

The appropriate hours-use factor was mapped to each respective subgrouping in the OEB CPS scenario results based upon the applicable end -use, sub-sector and region. The conversion between annual consumption and peak demand was then conducted using the following formula:

$$Peak\ Demand\ Savings\ \left(\frac{m^3}{h}\right) = \frac{Scenario\ Measure\ Savings\ (m^3)}{Hours\text{-}Use\ Factor\ (h)}$$

2. Base Year & Reference Case

The first step in estimating the potential impacts of DSM measures on natural gas peak period demand was to estimate the relative contributions of the Gas Utilities' customers to peak period demand prior to the implementation of any DSM measures. This starting point for the analysis is referred to as the base year. The base year for this study is the calendar year 2014.[108]

The reference case, which stretches to 2026, provides a forecast of natural gas demand in the absence of incremental DSM. As such, the reference case provides a point of comparison for the calculation of new energy-saving opportunities associated with each of the scenarios that are assessed within this study. Although the reference case does not include any incremental DSM during the study period, it does include the ongoing effects of DSM activity initiated before the study period. It also presents a scenario in which policy, legislation, and regulation continue to exist as they are today. The inclusion of these first two areas of DSM activity into the reference case ensures that all natural conservation has been considered.

The analysis for this study relied on the development of load profiles for energy consumption at the sub-sector and end-use levels. The sub-sector and end-use load profiles, which were developed based on archetype building modeling, estimate how energy consumption and measured savings are distributed during the five peak periods considered. The analysis is calibrated to utility gate station data to account for coincident peak use, and to ensure consistency with the utility service territories.

This section summarizes the results of the base year and reference case analysis, showing how the Gas Utilities' various customers contribute to peak period demand throughout the study period. For each customer type and end-use, the contribution to peak period demand is compared to the contribution to annual consumption to identify which sub-sectors and end-uses have a larger relative impact on peak period demand.

2.1 All Sector Results

2.1.1 Enbridge

A breakdown of peak hour demand by sector for the Enbridge service territory is summarized in Exhibit 42. The exhibit shows the peak hour demand from the base year 2014 to the reference case milestone year of 2026. The exhibit shows the results for peak period #2 (7-8 a.m.), since this was found to be the peak period of interest (peak hour) based on our analysis. As shown, the commercial and residential sectors provide the greatest contribution to peak hour demand, contributing to 51% and 43% of the base year peak hour demand, respectively. This is followed by the industrial sector, which accounts for the other 7% of the base year peak hour demand. By the reference case milestone year of 2026, the residential sector contribution is slightly lower at 49%, followed by 45% peak hour demand from the commercial sector, and 6% of the peak hour demand from the industrial sector.

[108] This lines up with the base year considered for the OEB CPS.

The natural gas demand during the peak hour (7-8 a.m.) for all combined sectors in the Enbridge service territory is expected to increase from approximately 5.01 million m^3 in 2014 to approximately 5.62 million m^3 in 2026, representing an increase of approximately 12%.

Exhibit 42: Peak Hour Demand by Sector and Milestone Year for Enbridge's Service Territory

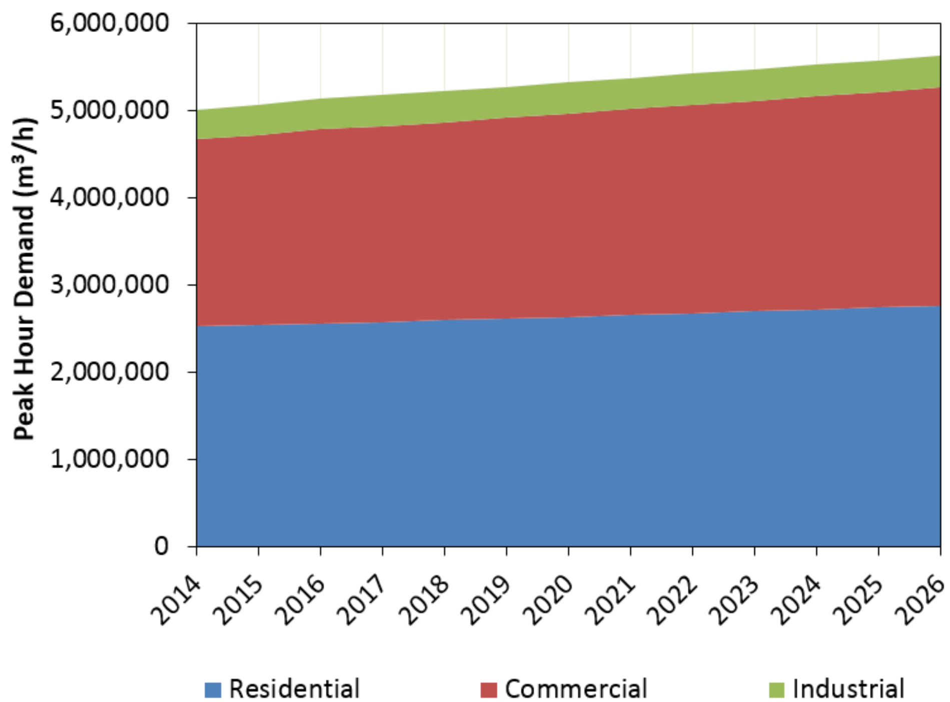
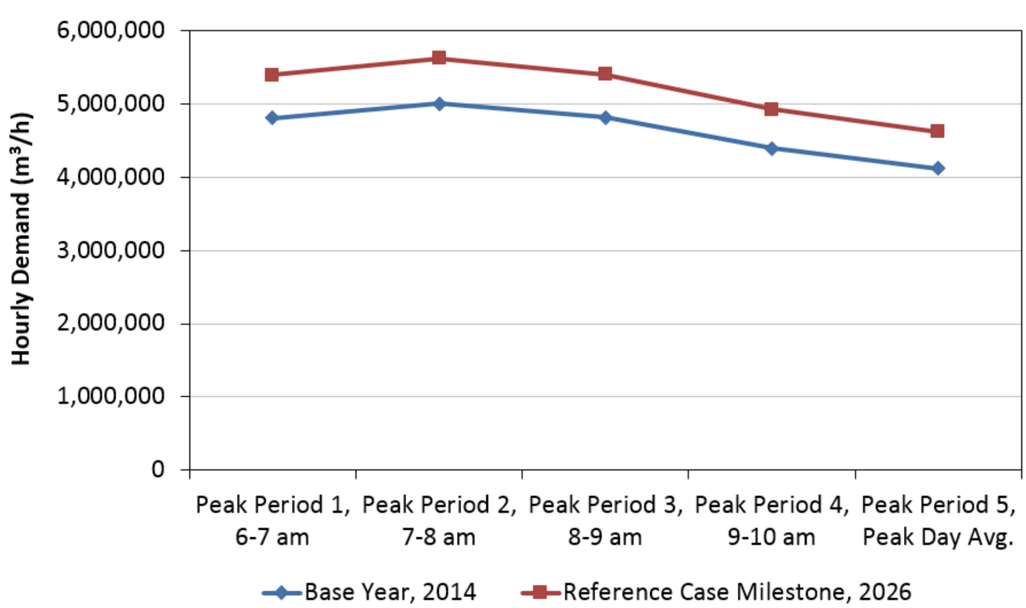


Exhibit 43 provides a comparison of the five peak periods for the Enbridge service territory, showing the base year peak period demand and reference case milestone year 2026 demand across each of the peak periods. As shown, the overall peak period demand for Enbridge occurs during peak period #2 (7-8 a.m.), with peak period #1 (6-7 a.m.) close behind.

Exhibit 43: Total Hourly Demand by Peak Period for Enbridge Service Territory (2014 vs. 2026)



2.1.2 Union Gas

Exhibit 44 summarizes the breakdown of peak hour demand by sector for the Union Gas' service territory and shows the peak hour demand from the base year 2014 to the reference case milestone year of 2026. The exhibit shows the results for peak period #2 (7-8 a.m.), since this was found to be the peak hour based on our analysis. As shown, each sector provides a similar contribution level to peak hour demand, with residential leading at 35%. This is followed by the commercial and industrial sectors, which respectively account for the other 32% and 33% of the base year peak hour demand. By the reference case milestone year of 2026, the commercial sector contribution is slightly lower at 33%, the industrial sector contribution is at 32%, while the residential sector remains at 35%.

Natural gas demand during the peak hour (7-8 a.m.) for all combined sectors in the Union Gas service territory is expected to increase from approximately 3.52 million m^3 in 2014 to approximately 3.81 million m^3 in 2026, representing an overall increase of approximately 8%.

Exhibit 44: Peak Hour Demand by Sector and Milestone Year for Union Gas Service Territory

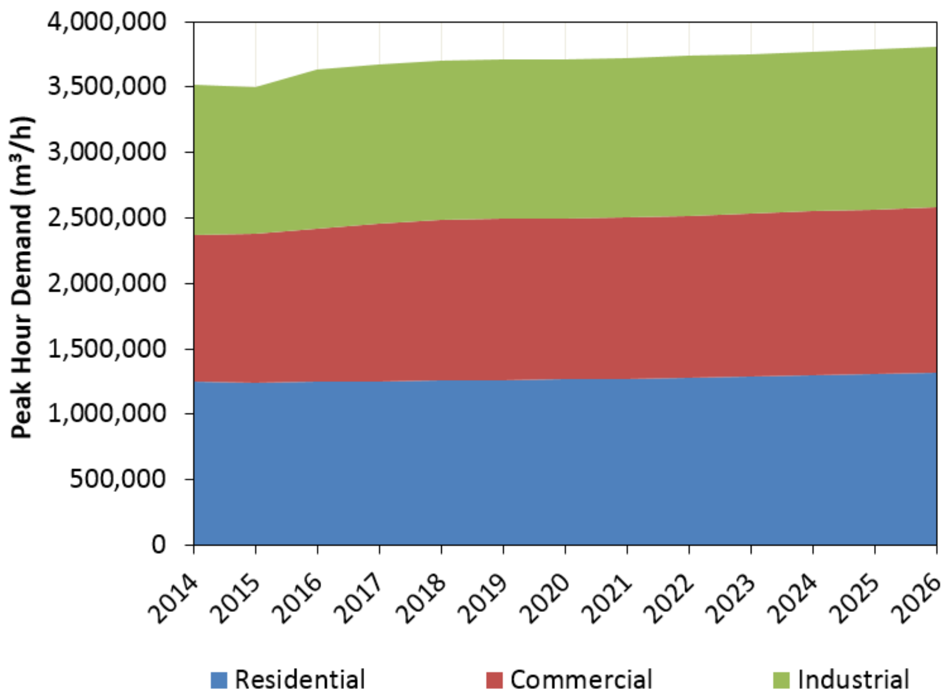
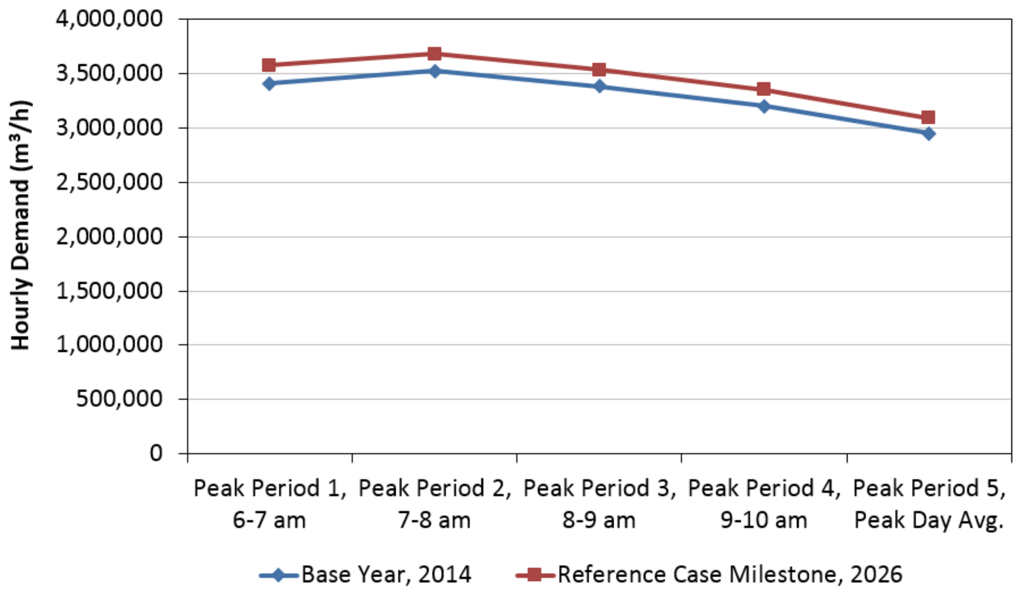


Exhibit 45 provides a comparison of the five peak periods for the Union Gas service territory, showing the base year hourly demand and reference case milestone year 2026 demand across each of the peak periods. As shown, the overall peak period demand occurs during peak period #2 (7-8 a.m.), followed by peak period #1 (6-7 a.m.) and peak period #3 (8-9 a.m.).

Exhibit 45: Total Hourly Demand by Peak Period for Union Gas Service Territory (2014 vs. 2026)



2.2 Residential Sector Results

2.2.1 Enbridge

Exhibit 46 summarizes the residential sector breakdown of peak hour demand by sub-sector and end-use for the Enbridge service territory, and shows the peak hour demand from the base year 2014 to the reference case milestone year of 2026. The exhibit shows the results for peak period #2 (7-8 a.m.), since this was found to be the peak hour based on our analysis.

As shown, pre-1996 dwellings make the largest contribution to peak hour demand (56% of the 2026 peak hour demand). From an end-use perspective, space heating is the largest contributor, making up 91% of the 2026 peak hour demand.

The exhibit also illustrates that the Enbridge's residential sector total natural gas demand during the peak hour (7-8 a.m.) is expected to increase steadily from approximately 2.53 million m^3 in 2014 to approximately 2.84 million m^3 in 2026, representing an overall increase of approximately 12%. This increase in demand during the peak hour is mainly driven by the addition of new homes to the housing stock. The contribution of space heating to peak hour demand is expected to decrease slightly from 92% in 2014 to 91% in 2026.

Exhibit 46: Peak Hour Demand by Sub-sector, End-Use and Milestone Year for Enbridge's Residential Sector

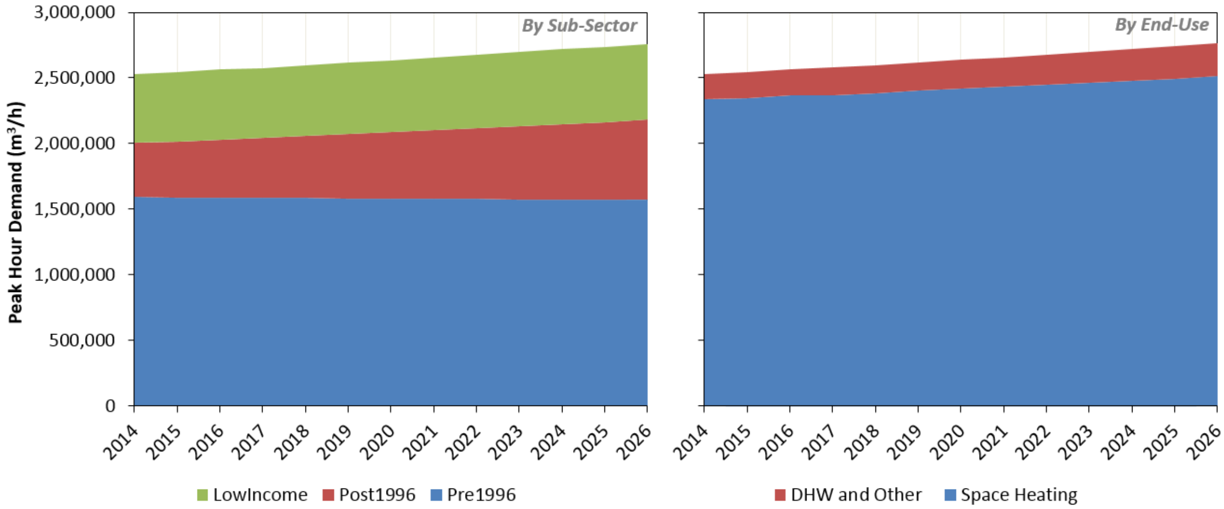
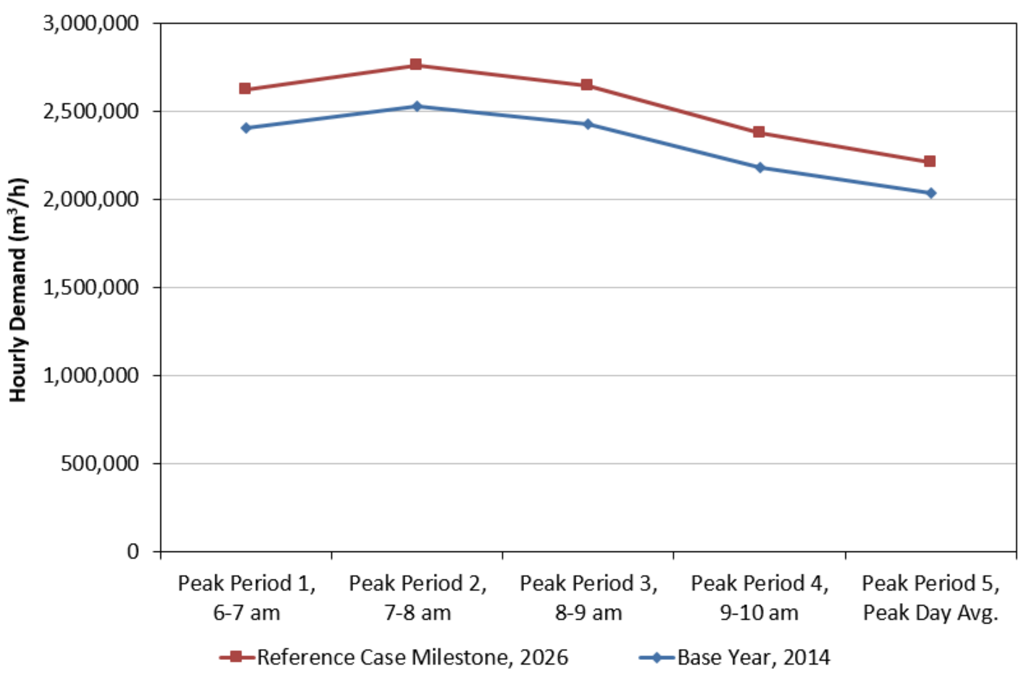


Exhibit 47 provides a comparison of the five peak periods for the Enbridge service territory, showing the base year hourly demand and reference case milestone year 2026 demand across each of the peak periods. As shown, the overall residential sector peak occurs during peak period #2 (7-8 a.m.), with peak period #3 (8-9 a.m.) and peak period # 1 (6-7 a.m.) close behind.

Exhibit 47: Total Hourly Demand by Peak Period for Enbridge's Residential Sector (2014 vs. 2026)



2.2.2 Union Gas

Exhibit 48 summarizes the residential sector breakdown of peak hour demand by sub-sector and end-use for the Union Gas service territory and shows the peak hour demand from the base year 2014 to the reference case milestone year of 2026. The exhibit shows the results for peak period #2 (7-8 a.m.), since this was found to be the peak hour based on our analysis.

As shown, pre-1996 dwellings make the largest contribution to peak hourly demand. During the peak hour, pre-1996 homes account for approximately 64% of the total 2026 peak hour demand, while low-income dwellings account for 21%, and post-1996 dwellings account for 15% of the 2026 peak hour demand.

The exhibit also illustrates that Union Gas' residential sector total natural gas demand during the peak hour (7-8 a.m.) is expected to increase steadily from approximately 1.25 million m^3 in 2014 to approximately 1.35 million m^3 in 2026, representing an increase of approximately 8%. This increase in demand during the peak hour is mainly driven by the addition of new homes to the housing stock. The contribution of space heating to peak hour demand is expected to decrease slightly from 90% in 2014 to 89% in 2026.

Exhibit 48: Peak Hour Demand by Sub-sector, End-Use and Milestone Year for Union Gas' Residential Sector

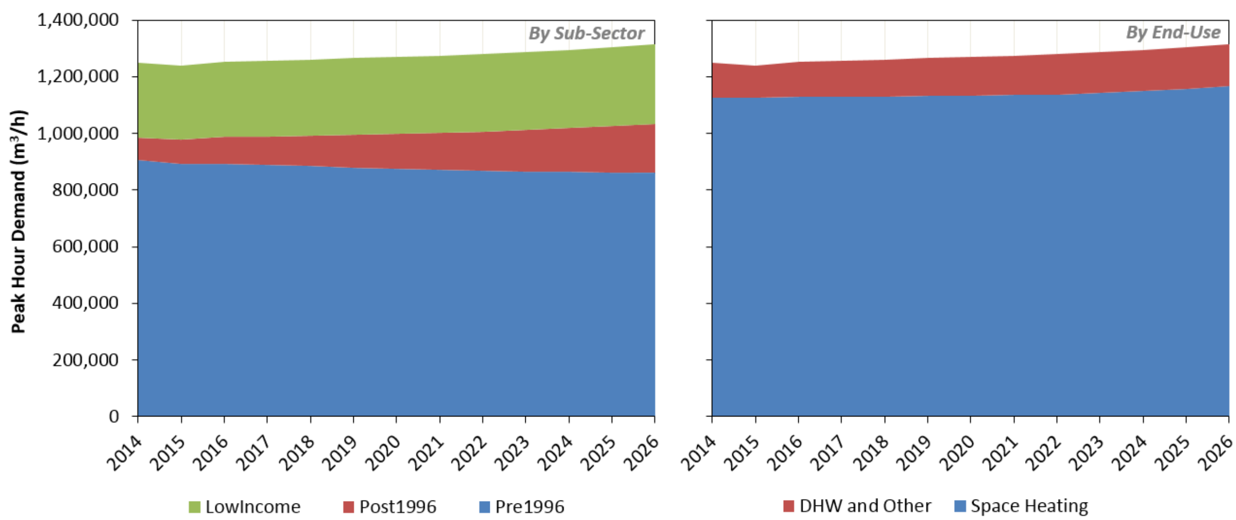
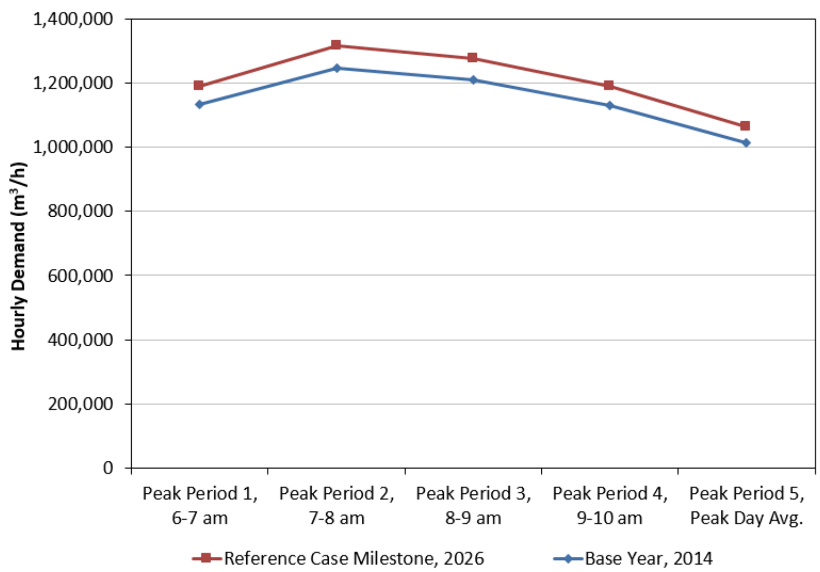


Exhibit 49 provides a comparison of the five peak periods for the Union Gas service territory, showing the base year hourly demand and reference case milestone year 2026 demand across each of the peak periods. As shown, Union Gas' residential sector peak occurs during peak period #2 (7-8 a.m.), with peak period #3 (8-9 a.m.) close behind.

Exhibit 49: Total Hourly Demand by Peak Period for Union Gas' Residential Sector (2014 vs. 2026)



2.3 Commercial Sector Results

2.3.1 Enbridge

Exhibit 50 summarizes the commercial sector breakdown of peak hour demand by sub-sector and end-use for the Enbridge service territory and shows the peak hour demand from the base year 2014 to the reference case milestone year of 2026. The exhibit shows the results for peak period #2 (7-8 a.m.), since this was found to be the peak hour based on our analysis.

As shown, apartments and offices make the largest contribution to peak hour demand (28% of the peak hour demand). From an end-use perspective, space heating is the largest contributor, making up 92% of the peak hour demand.

The exhibit also illustrates that Enbridge's commercial sector total natural gas demand during the peak hour (7-8 a.m.) is expected to increase steadily from approximately 2.14 million m^3 in 2014 to approximately 2.50 million m^3 in 2026, representing an increase of approximately 17%. This increase is mainly driven by a growth in demand for apartments and offices.

Exhibit 50: Peak Hour Demand by Sub-sector, End-Use and Milestone Year for Enbridge's Commercial Sector

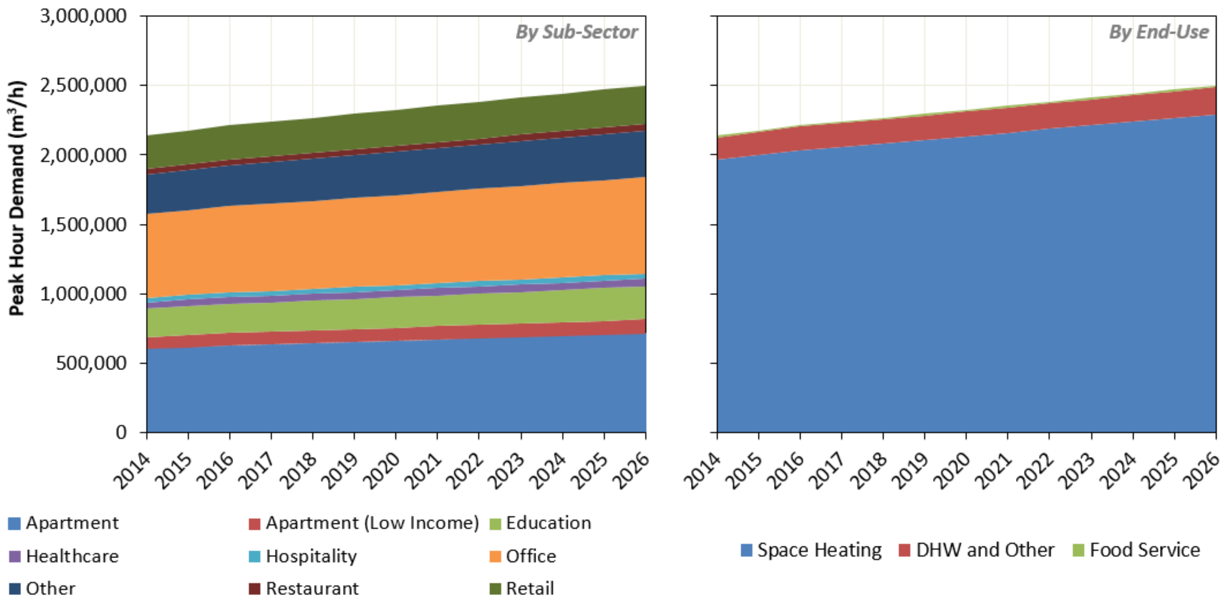
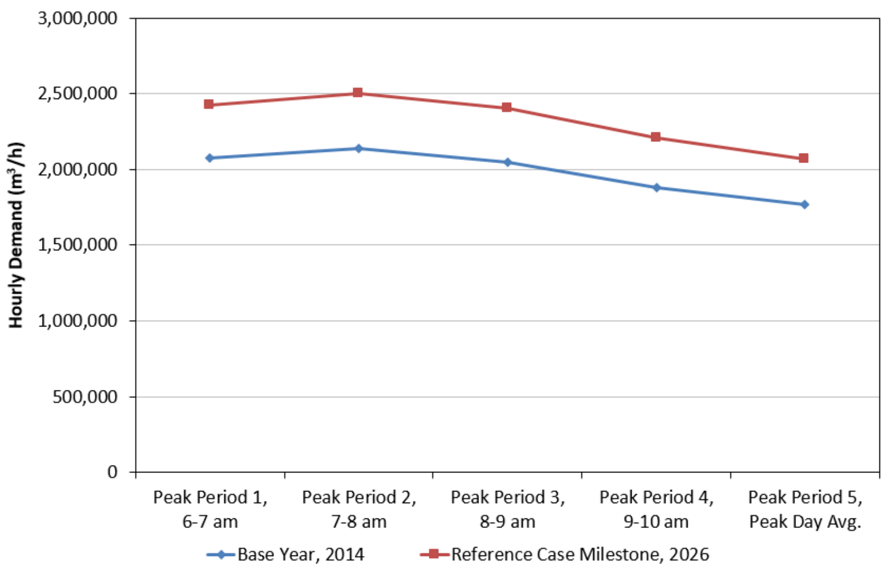


Exhibit 51 provides a comparison of the five peak periods for the Enbridge service territory, showing the base year hourly demand and reference case milestone year 2026 demand across each of the peak periods. As shown, Enbridge's commercial sector peak occurs during peak period #2 (7-8 a.m.), followed by peak period #1 (6-7 a.m.).

Exhibit 51: Total Hourly Demand by Peak Period for Enbridge's Commercial Sector (2014 vs. 2026)



2.3.2 Union Gas

Exhibit 52 summarizes the commercial sector breakdown of peak hour demand by sub-sector and end-use for the Union Gas service territory and shows the peak hour demand from the base year 2014 to the reference case milestone year of 2026. The exhibit shows the results for peak period #2 (7-8 a.m.), since this was found to be the peak hour based on our analysis.

As shown, "other" buildings make the largest contribution to peak hour demand (32% of the peak hour demand). From an end-use perspective, space heating is the largest contributor, making up 93% of the peak hour demand.

The exhibit also illustrates that Union Gas' commercial sector total natural gas demand during the peak hour (7-8 a.m.) is expected to increase steadily from approximately 1.12 million m^3 in 2014 to approximately 1.27 million m^3 in 2026, an increase of approximately 14%. This increase is mainly driven by growth from other, offices, retail, and education facilities.

Exhibit 52: Peak Hour Demand by Sub-sector, End-Use and Milestone Year for Union Gas' Commercial Sector

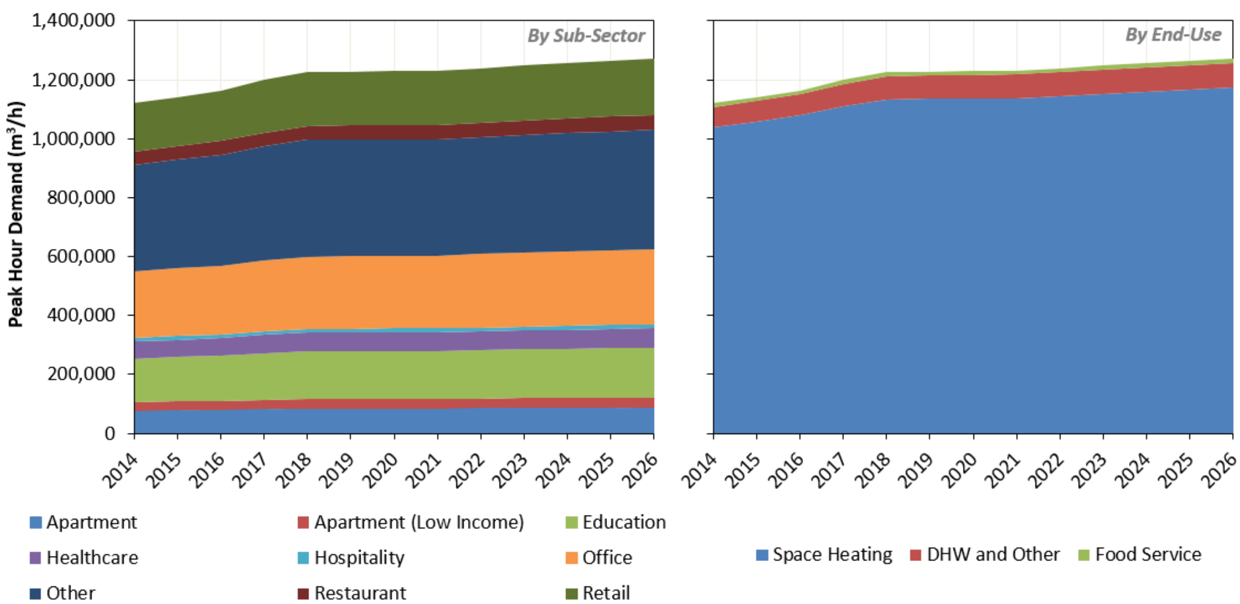
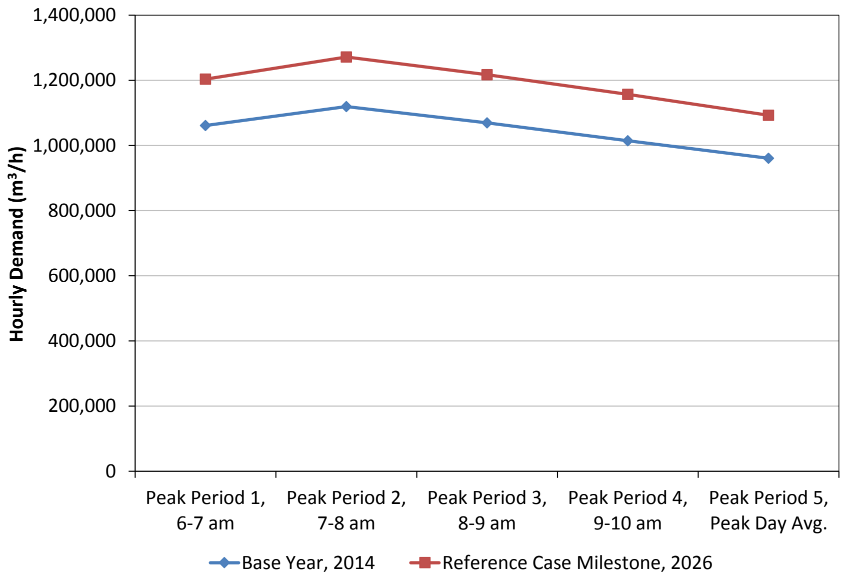


Exhibit 53 provides a comparison of the five peak periods for the Union Gas service territory, showing the base year hourly demand and reference case milestone year 2026 demand across each of the peak periods. As shown, Union Gas' commercial sector peak occurs during peak period #2 (7-8 a.m.), followed by peak period #3 (8-9 a.m.).

Exhibit 53: Total Hourly Demand by Peak Period for Union Gas' Commercial Sector (2014 vs. 2026)



2.4 Industrial Sector Results

2.4.1 Enbridge

Exhibit 54 summarizes the industrial sector breakdown of peak hour demand by sub-sector and end-use for the Enbridge service territory and shows the peak hour demand from the base year 2014 to the reference case milestone year of 2026. The exhibit shows the results for peak period #2 (7-8 a.m.), since this was found to be the peak hour based on our analysis.

As shown, manufacturing facilities make the largest contribution to peak hour demand (56% of the peak hour demand). From an end-use perspective, the HVAC and other end-use is the largest contributor, making up 51% of the peak hour demand.

The exhibit also illustrates that Enbridge's industrial sector total natural gas demand during the peak hour (7-8 a.m.) is expected to increase steadily from approximately 0.34 million m^3 in 2014 to approximately 0.36 million m^3 in 2026, representing an increase of approximately 6%. This increase is mainly driven by manufacturing facilities and heavy process industries.

Exhibit 54: Peak Hour Demand by Sub-sector, End-Use and Milestone Year for Enbridge's Industrial Sector

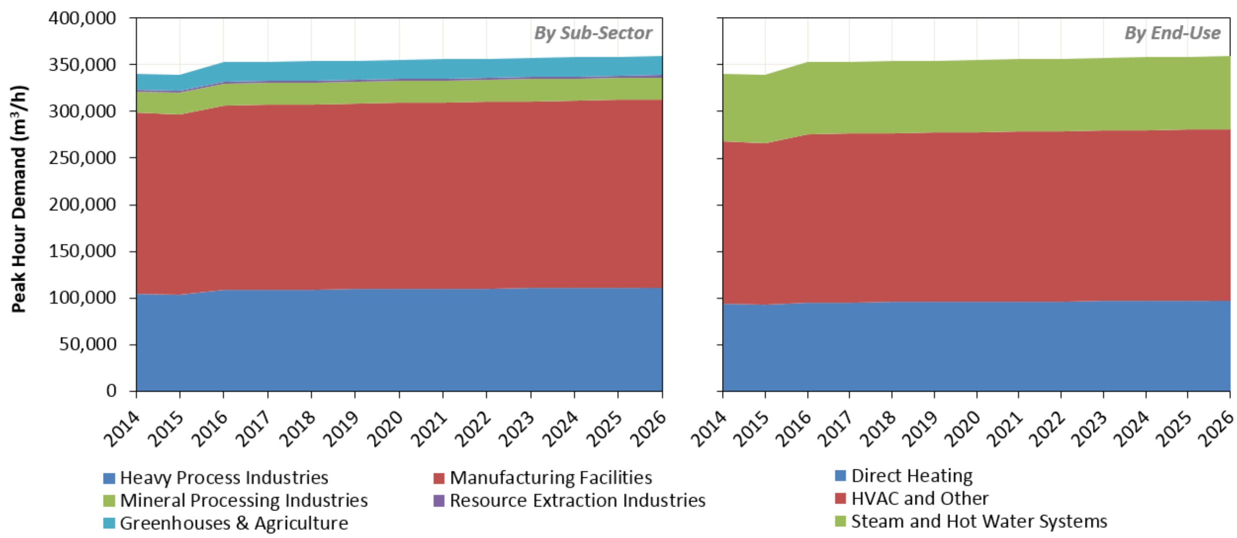
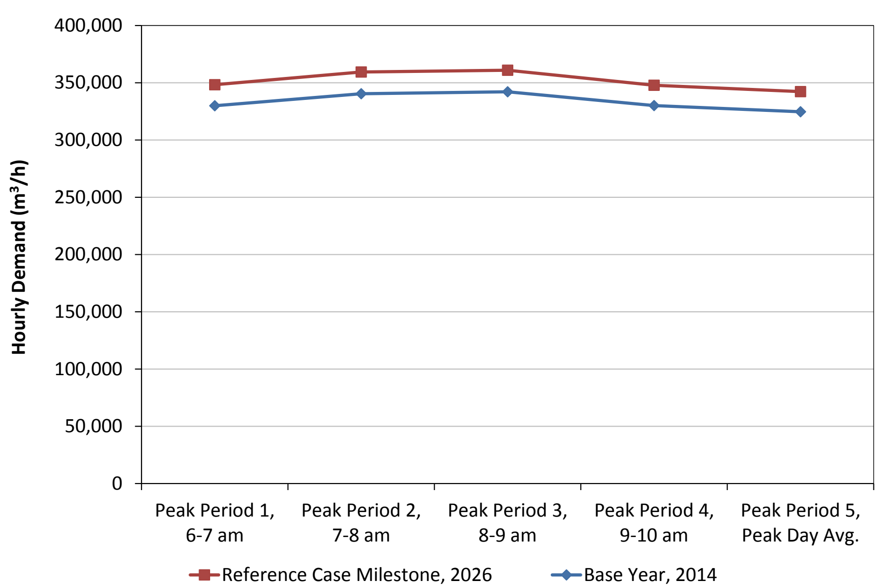


Exhibit 55 provides a comparison of the five peak periods for the Enbridge service territory, showing the base year hourly demand and reference case milestone year 2026 demand across each of the peak periods. As shown, Enbridge's industrial sector peak occurs during peak period #3 (8-9 a.m.).

Exhibit 55: Total Hourly Demand by Peak Period for Enbridge's Industrial Sector (2014 vs. 2026)



2.4.2 Union Gas

Exhibit 56 summarizes the industrial sector breakdown of peak hour demand by sub-sector and end-use for the Union Gas service territory and shows the peak hour demand from the base year 2014 to the reference case milestone year of 2026. The exhibit shows the results for peak period #2 (7-8 a.m.), since this was found to be the peak hour based on our analysis.

As shown, heavy process industries make the largest contribution to peak hour demand (38% of the peak hour demand). From an end-use perspective, the HVAC and other end-use is the largest contributor, making up 39% of the peak hour demand, followed very closely by direct heating which makes up 37% of the peak hour demand.

The exhibit also illustrates that Union Gas' industrial sector total natural gas demand during the peak hour (7-8 a.m.) is expected to increase steadily from approximately 1.16 million m^3 in 2014 to approximately 1.22 million m^3 in 2026, an increase of approximately 6%. This increase is mainly driven by growth in heavy process industries and in the Greenhouses and Agriculture sub-sector.

Exhibit 56: Peak Hour Demand by Sub-sector, End-Use and Milestone Year for Union Gas' Industrial Sector

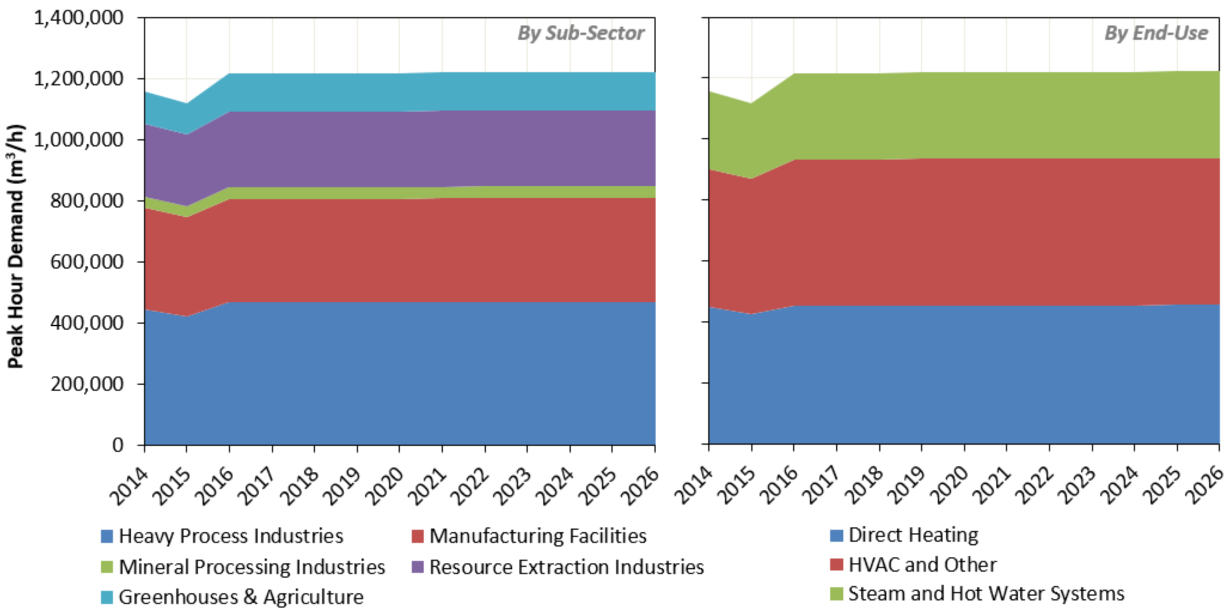
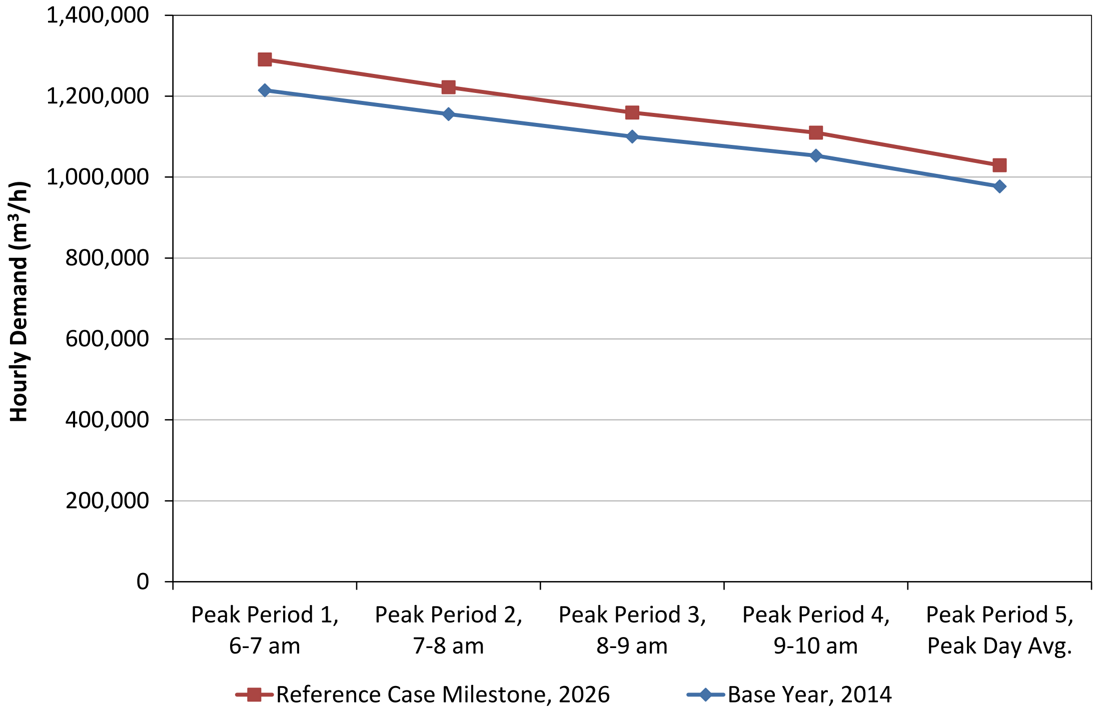


Exhibit 57 provides a comparison of the five peak periods for the Union Gas service territory, showing the base year hourly demand and reference case milestone year 2026 demand across each of the peak periods. As shown, Union Gas' industrial sector peak occurs during peak period #1 (6-7 a.m.), followed by peak period #2 (7-8 a.m.).

Exhibit 57: Total Hourly Demand by Peak Period for Union Gas' Industrial Sector (2014 vs. 2026)



3. Achievable Potential

This section summarizes the results of the achievable potential analysis results, showing how the efficiency improvements resulting from DSM measures contribute to peak period demand savings. This is compared against the consumption savings results from the OEB CPS to identify which sub-sectors and end-uses have a larger relative impact on the achievable peak period demand savings. Although the technical and economic potential were estimated as part of ICF's analysis as well, this report does not focus on the results from these scenarios since they are more theoretical and less instructive.

Achievable potential is defined as the portion of the economic conservation potential that takes into account realistic market penetration rates of cost-effective measures over the study period, and is based on the following factors:

- market barriers
- customer preferences
- incentive levels
- aggressiveness of marketing efforts
- historic program experience
- competing DSM measures
- increased collaboration between natural gas and electric utilities
- experience in leading jurisdictions
- other factors

As noted in Section IV.1, the IRP study analysis leverages the results of the OEB CPS constrained achievable potential (achievable potential) scenario. This scenario represents the natural gas savings achieved through efficiency improvements resulting from programs at the DSM budget levels established by the OEB's 2015-2020 DSM Decision over the study period.

3.1 All Sector Results

3.1.1 Enbridge

Exhibit 58 provides a comparison of the achievable potential peak demand savings across five peak periods for the Enbridge service territory and for all sectors combined. As shown, the highest achievable potential peak period demand savings occur during peak period #5 (the average peak day), followed by peak period #4 (9-10 a.m.).

The adoption of all achievable measures for all sectors in the Enbridge service territory could potentially reduce natural gas demand during the peak hour (7-8 a.m.) by 3.7% by 2026, or from a projected reference case peak hour demand of 5.62 million m^3 to an achievable potential peak hour demand of 5.41 million m^3. The exhibit also illustrates that DSM is not expected to shift the timing of peak hour demand, since it can be seen in the accompanying chart that the overall peak period demand for Enbridge still occurs during peak period #2 (7-8 a.m.).

Exhibit 58: Achievable Potential Peak Demand Savings for All Sectors in Enbridge Gas Service Territory (2026)

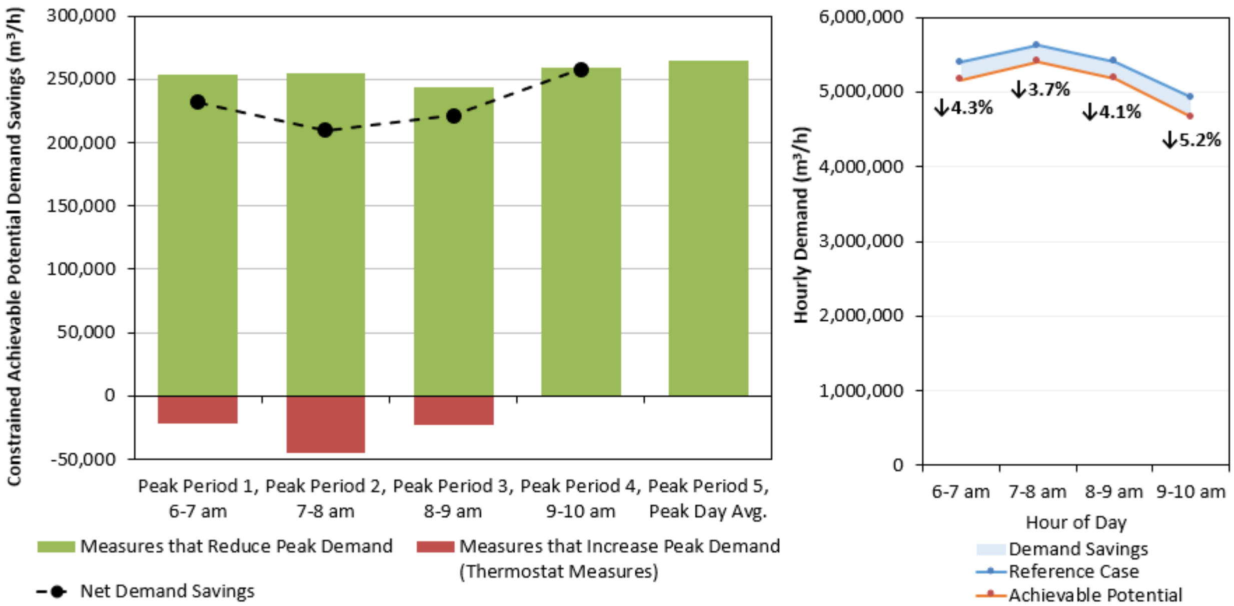


Exhibit 59 presents the achievable potential peak demand savings without thermostat measures. As shown, without the impact of the thermostat measures, the natural gas peak demand can be reduced during the peak hour (7-8 a.m.) by 4.5% by 2026, or from approximately 5.62 million m^3 to 5.37 million m^3. The exhibit shows that the peak demand savings are more evenly spread out during morning lift period, with the highest savings now occurring during the system peak hour, peak period #2 (7-8 a.m.).

Exhibit 59: Achievable Potential Peak Demand Savings for All Sectors (excluding thermostat measures) in Enbridge Gas Service Territory (2026)

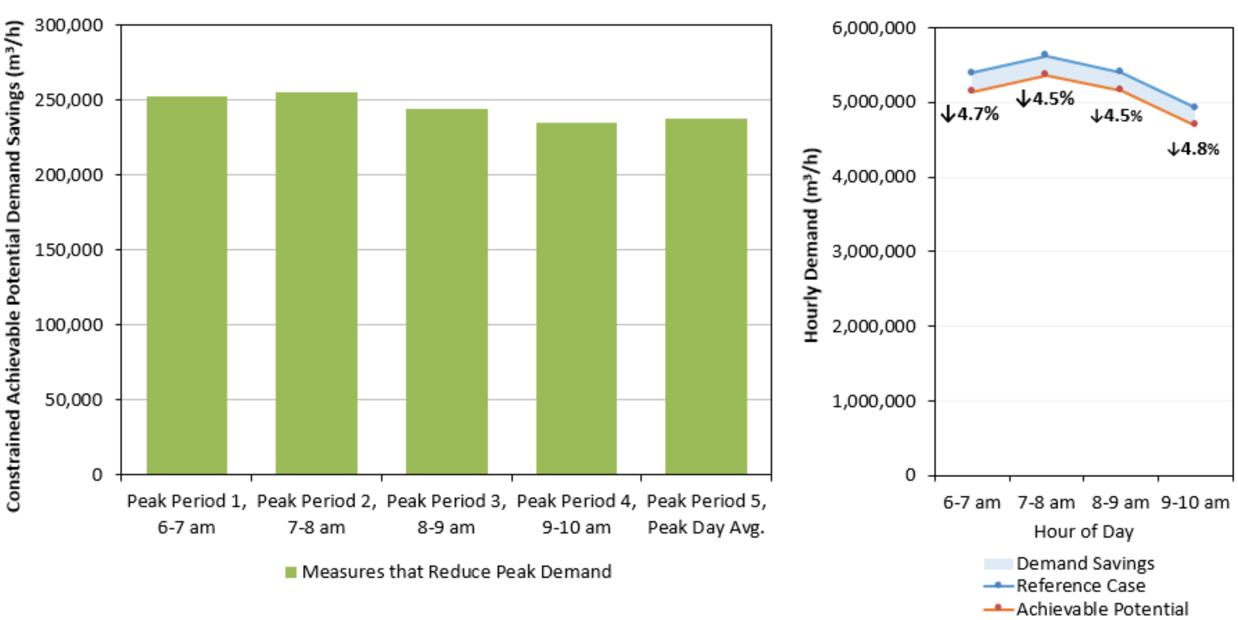
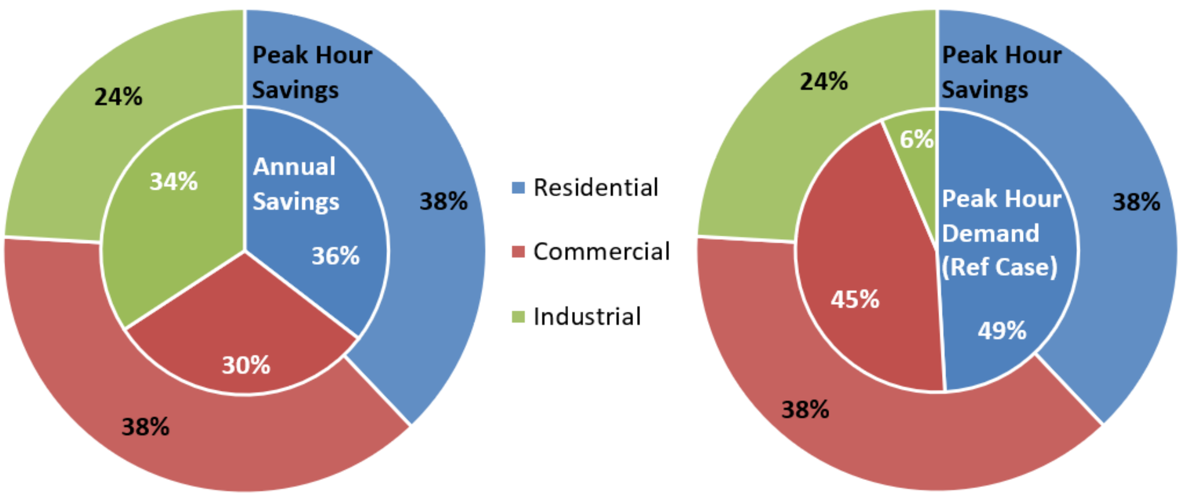


Exhibit 60 provides a comparison of the relative contribution to peak hour demand savings, annual savings, and reference case peak hour demand for all sectors in Enbridge's service territory. As shown in the left pie chart, the commercial and residential sectors provide the greatest contributions to the achievable potential peak hour demand savings in the Enbridge service territory, with each sector contributing 38% of the total. By comparison, the industrial sector only contributes 24% to the total achievable potential peak hour demand savings in Enbridge's service territory.

The commercial sector has a larger contribution to peak hour demand savings, relative to the annual consumption savings, than do the residential and industrial sectors. The commercial sector accounts for 38% of peak hour demand savings, while only accounting for 30% of annual savings. The residential sector, which also represents 38% of peak hour savings, represents 36% of annual savings, while the industrial sector contributes only 24% of peak hour savings compared to 34% of annual savings.

As shown in the right pie chart, the peak hour savings relative to the reference case peak hour demand are highest for the industrial sector. Despite only representing 6% of the reference case peak hour demand, the industrial sector accounts for 24% of peak hour savings.

Exhibit 60: Achievable Potential – Relative Contribution to Peak Hour Savings, Annual Savings, and Reference Case Peak Hour Demand by Sector in Enbridge Gas Service Territory (2026)



3.1.2 Union Gas

Exhibit 61 provides a comparison of the achievable potential peak demand savings across five peak periods for the Union Gas service territory and for all sectors combined. As shown, the highest peak period demand savings occur during peak period #1 (6-7 a.m.), followed by peak period #4 (9-10 a.m.).

The adoption of all achievable measures in the Union Gas service territory for all sectors could potentially reduce natural gas demand during the peak hour (7-8 a.m.) by 5.5% by 2026, or from a projected reference case peak hour demand of 3.81 million m^3 to an achievable potential peak hour demand of 3.60 million m^3. This exhibit also illustrates that DSM is not expected to shift the timing of peak hour demand.

Exhibit 61: Achievable Potential Peak Demand Savings for All Sectors in Union Gas Service Territory (2026)

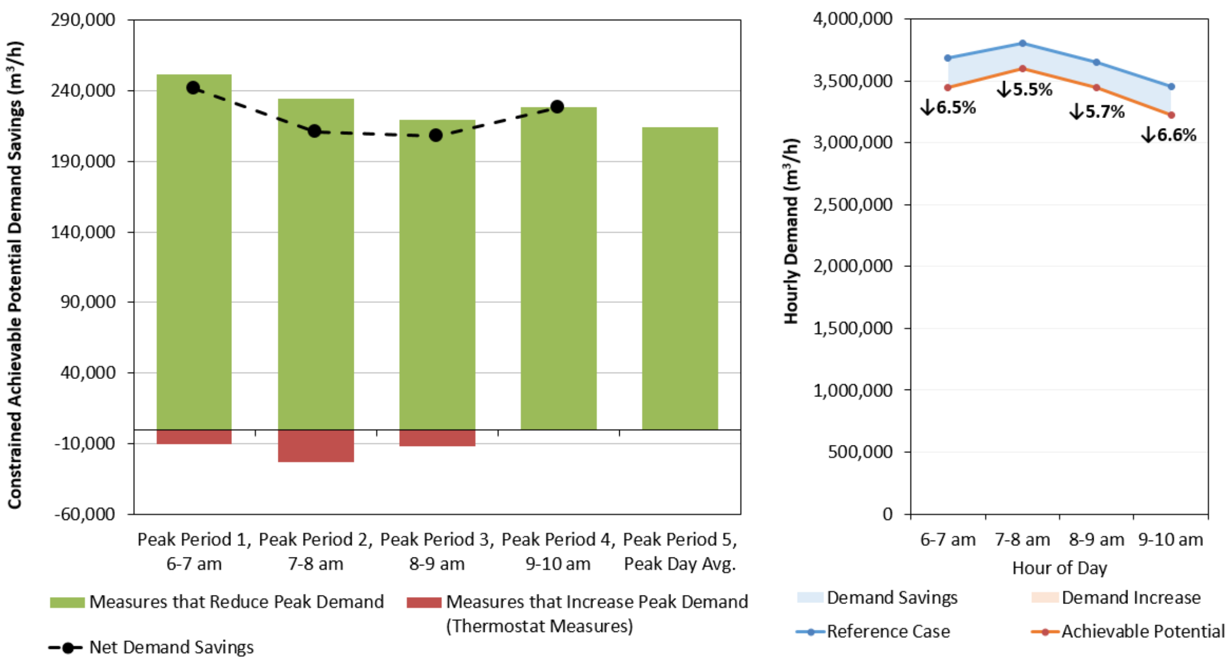


Exhibit 62 presents the achievable potential peak demand savings without thermostat measures. As shown, without the impact of the thermostat measures, the natural gas peak demand can be reduced during the peak hour (7-8 a.m.) by 6.2% by 2026, or from approximately 3.81 million m^3 to 3.57 million m^3. The exhibit shows that the demand savings are more evenly spread out during morning lift period, with highest demand savings still occurring in peak period #1 (6-7 a.m.).

Exhibit 62: Achievable Potential Peak Demand Savings for All Sectors (excluding thermostat measures) in Union Gas Service Territory (2026)

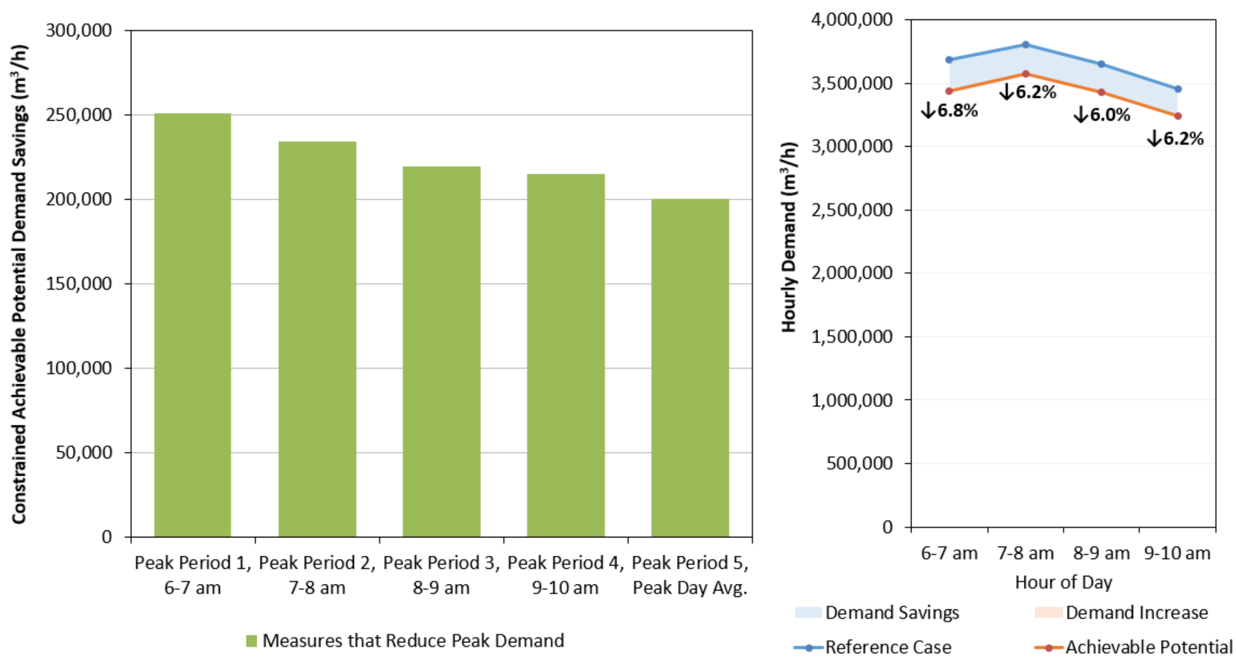
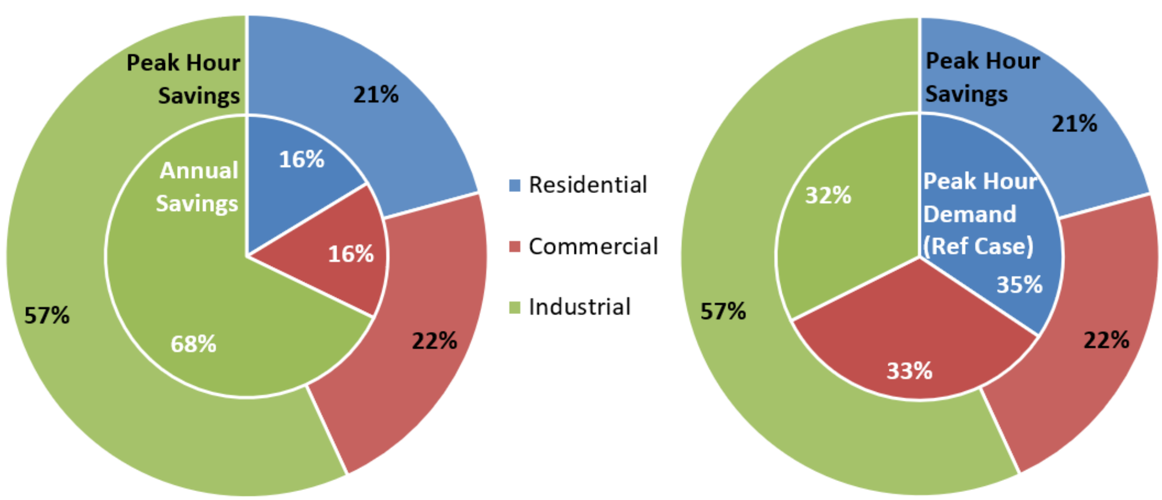


Exhibit 63 provides a comparison of the relative contribution to peak hour demand savings, annual savings, and reference case peak hour demand for all sectors in Union Gas' service territory. As shown in the exhibit (left pie chart), the industrial sector provides the greatest contribution to achievable potential peak hour demand savings in the Union Gas service territory, with the industrial sector contributing to 57% of the Union Gas total. This is followed by the commercial sector contributing 22% and the residential sector contributing 21% to the Union Gas total.

The commercial and residential sectors both have larger contribution to peak hour demand savings relative to the annual consumption savings. In contrast, the industrial sector has a smaller relative contribution to peak hour demand savings than to annual savings. The commercial sector contribution to peak hour demand savings is 22% compared to 16% for annual savings. The residential sector represents 21% of peak hour demand savings vs. 16% for annual savings, while the industrial sector contributes to 57% of peak hour demand savings and 68% of annual savings.

As shown in the right pie chart, it is also important to note that the peak hour demand savings relative to the reference case peak hour demand are highest for the industrial sector. The industrial reference case peak hour demand only represents 32% of the total reference case peak hourly demand but the industrial peak hour demand savings represent 57% of the total peak hour demand savings for all sectors.

Exhibit 63: Achievable Potential – Relative Contribution to Peak Hour Savings, Annual Savings, and Reference Case Peak Hour Demand by Sector in Union Gas Service Territory (2026)



3.2 Residential Sector Results

This section summarizes the residential sector achievable potential peak demand savings analysis results. The results are presented separately for the Gas Utilities and results are further segmented based on the peak hour, end-use categories, sub-sectors, and achievable DSM measures.

3.2.1 Enbridge

Exhibit 64 provides a comparison of the residential sector achievable potential peak period demand savings across five peak periods for Enbridge's service territory. As shown exhibit, the highest residential sector peak period demand savings occur during peak period #5 (the average peak), followed by peak period #4 (9-10 a.m.). With the adoption of all achievable measures in the Enbridge service territory for the residential sector, natural gas demand during the peak hour (7-8 a.m.) could potentially decrease by 1.9% by 2026, or from a projected reference case peak hour demand of 2.76 million m^3 to an achievable potential peak hour demand of 2.71 million m^3. This exhibit also illustrates that DSM is not expected to shift the timing of peak hour demand.

Exhibit 64: Achievable Potential Peak Demand Savings for Residential Enbridge Gas Service Territory (2026)

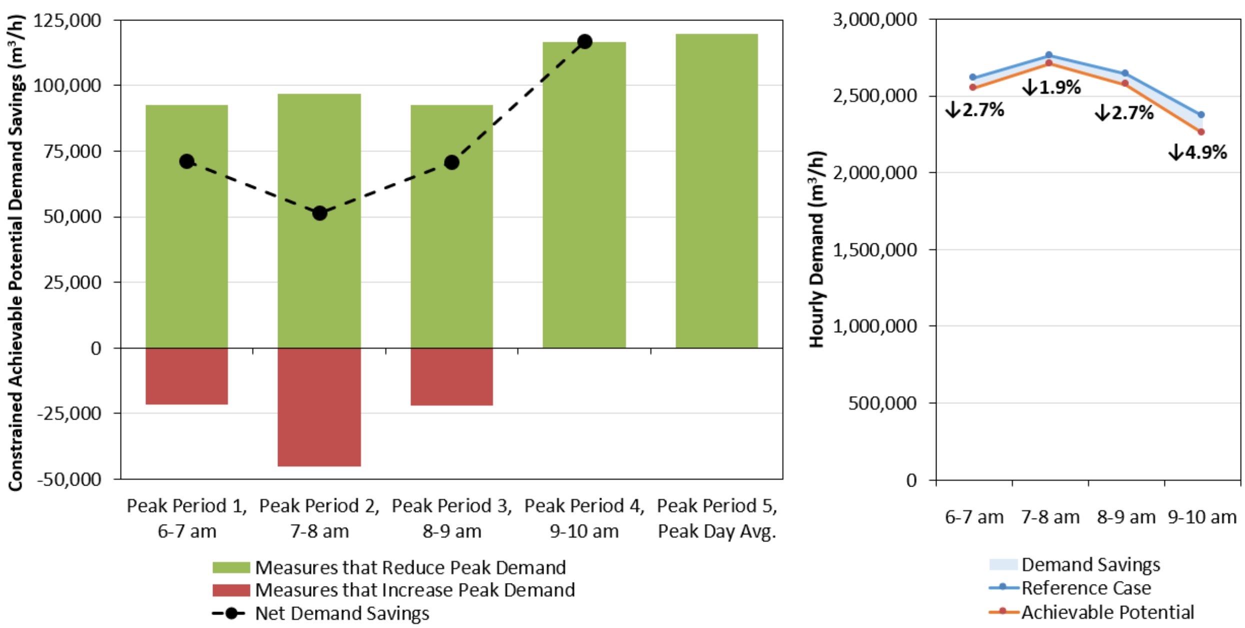
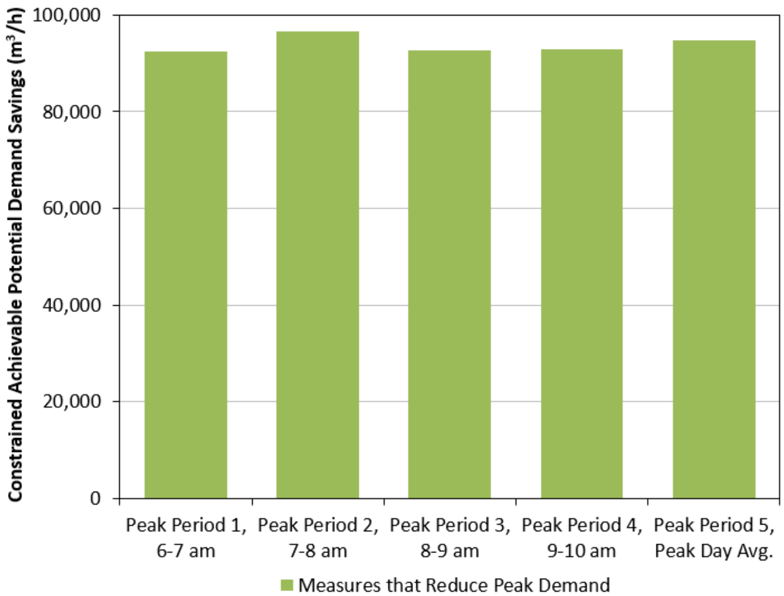


Exhibit 65 presents the residential Enbridge Gas achievable potential peak demand savings without thermostat measures. As shown, without the impact of the thermostat measures, the natural gas peak demand can be reduced during the peak hour (7-8 a.m.) by 3.5% by 2026, or from approximately 2.76 million m^3 to 2.66 million m^3. The exhibit shows that the demand savings are more evenly spread out during morning lift period, with highest demand savings occurring during peak period #2 (7-8 a.m.). Without the impact of the thermostat measures, the peak hour demand savings for the peak period of interest (7-8 a.m.) is significantly higher than the same hour shown in Exhibit 64 (and which includes the impact of thermostat measures).

Exhibit 65: Achievable Potential Peak Demand Savings (excluding thermostat measures) for Residential Enbridge Gas Service Territory (2026)



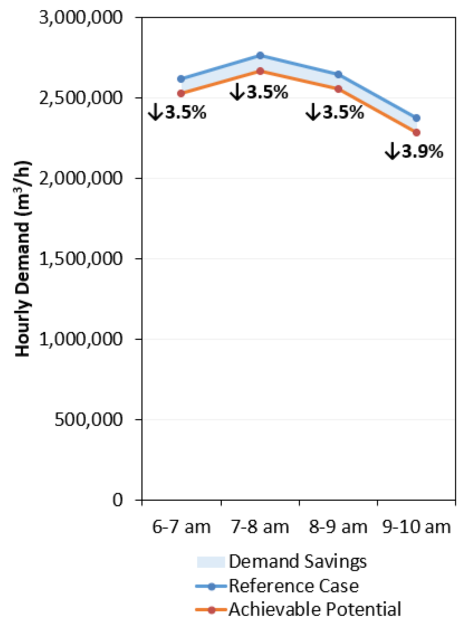


Exhibit 66 provides a comparison of the relative contribution to peak hour demand savings, annual savings, and reference case peak hour demand for the residential sub-sectors in Enbridge's service territory. This exhibit does not include the impact of thermostat measures, which increase the peak hour demand. This exhibit provides insight into whether or not any particular sub-sectors have a greater impact on demand savings during the peak hour. As the exhibit shows, the significance of pre-1996 and low-income dwellings is slightly higher for peak hour demand savings than for annual savings. The low-income sector accounts for 28% of annual savings and 29% of peak hour savings, while the pre-1996 homes account for 56% of annual savings and 59% of peak hour savings.

Post-1996 homes are less important from a peak hour demand perspective since they only account for 12% of peak hour savings, compared to 16% of annual savings. Post-1996 homes achieve a lower proportion of their energy savings during the peak hour demand period due to their better thermal envelopes. The exhibit also shows that low-income homes represent a disproportionately large share of peak hour savings relative to the reference case peak hour demand (representing 21% of reference case peak hour demand and 29% of the achievable peak hour demand savings).

Exhibit 66: Achievable Potential – Relative Contribution to Peak Hour Demand Savings, Annual Savings, and Reference Case Peak Hour Demand by Sub-sector for Residential Enbridge Gas Service Territory (2026)

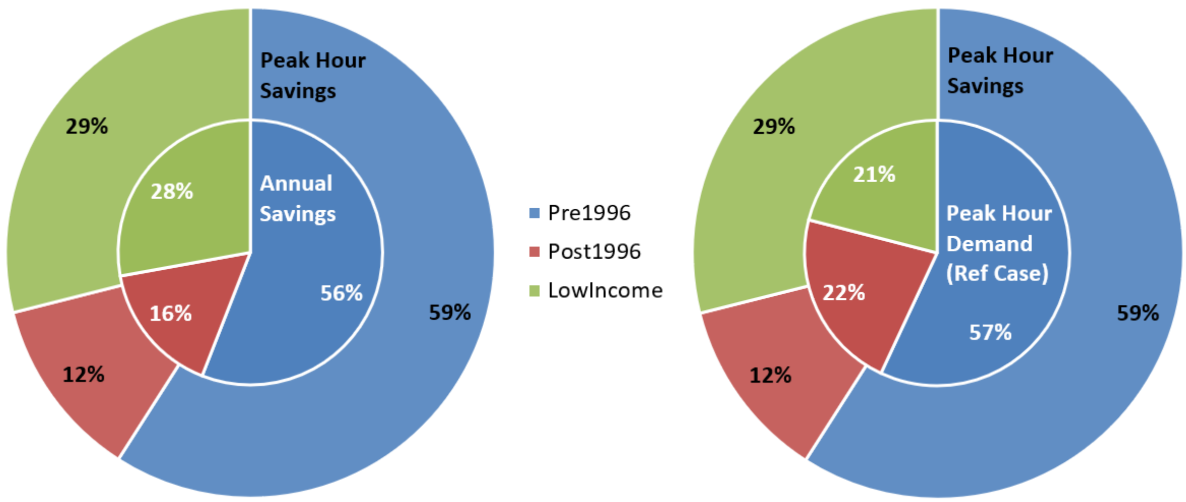


Exhibit 67 provides a comparison of the relative contribution to peak hour demand savings, annual savings, and reference case peak hour demand for the residential end-uses in Enbridge's service territory. The left pie chart provides insight into whether or not any particular end-use has a greater impact on peak hour demand savings than annual savings. Space heating demand savings are concentrated during the peak hour (contributing to 96% of overall peak hour demand savings), while DHW makes a smaller relative contribution (contributing to 4% of overall peak hour demand savings). However, it is important to note that DHW demand is not very focused on the peak hour period, as demonstrated by the fact that DHW accounts for 22% of annual savings but only 9% of reference case peak hour demand. The right pie chart shows that the space heating end-use also has the greatest potential for savings in comparison to its reference case peak hour demand (space heating makes up 91% of the reference case peak hour demand but 96% of peak hour demand savings).

Exhibit 67: Achievable Potential – Relative Contribution to Peak Hour Demand Savings, Annual Savings, and Reference Case Peak Hour Demand by End-Use for Residential Enbridge Gas Service Territory (2026)

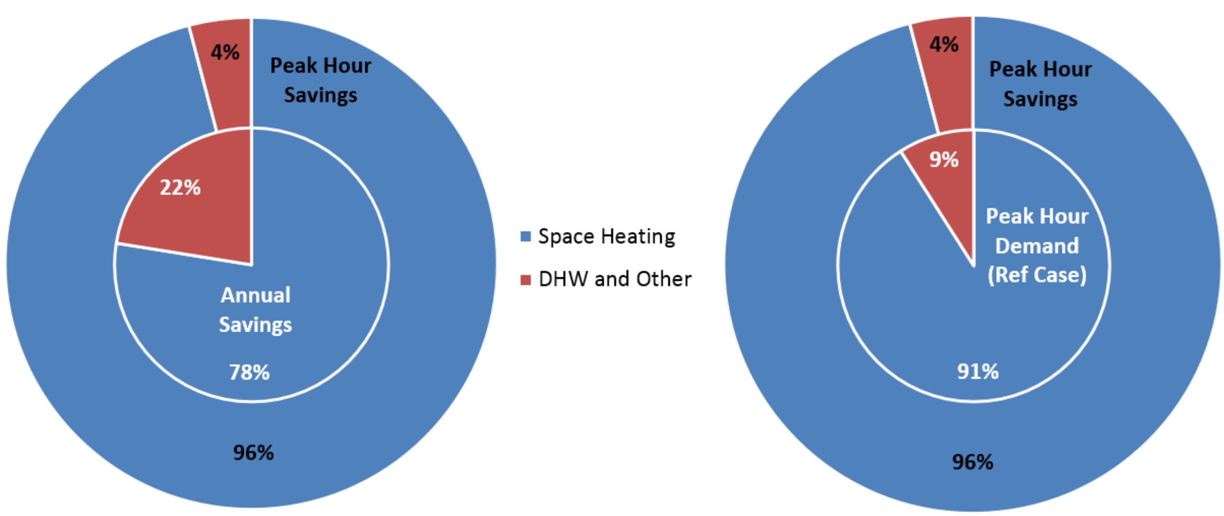
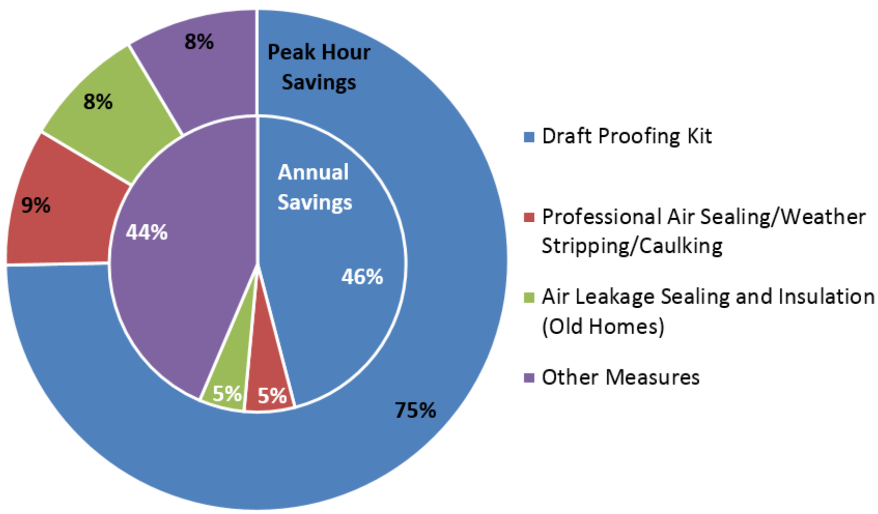


Exhibit 68 provides a comparison of the relative contributions to the 2026 peak hour demand savings and annual consumption savings for the residential measures in Enbridge's service territory. This exhibit does not include the impact of thermostat measures since they lead to increases in peak hour demand. The exhibit provides insight into whether or not any particular measures have a greater impact on achievable potential demand savings during the peak hour.

This exhibit shows that building envelope measures account for the greatest portion of the achievable potential peak hour demand savings, led by the draft proofing kit measure (75% of the savings). This is followed by the professional air sealing/weather stripping/caulking measure and the air leakage sealing and insulation measure, which account for 9% and 8% of achievable potential demand savings, respectively. The exhibit also shows that envelope measures have a disproportionately large impact on peak hour demand savings relative to their annual savings.

Exhibit 68: Achievable Potential – Relative Contribution to Peak Hour Savings and Annual Savings by Measure for Residential Enbridge Gas Service Territory (2026)



3.2.2 Union Gas

Exhibit 69 provides a comparison of the residential sector achievable potential peak period demand savings across five peak periods for all of Union Gas' service territory. As shown, the highest residential sector peak period demand savings occurs during peak period #4 (9-10 a.m.), followed by peak period #5 (the average peak day). With the adoption of all achievable measures in the Union Gas service territory for the residential sector, natural gas demand during the peak hour (7-8 a.m.) could potentially decrease by 1.9% by 2026, or from a projected reference case peak hour demand of 1.31 million m^3 to an achievable potential peak hour demand of 1.29 million m^3. This exhibit also illustrates that DSM is not expected to shift the timing of peak hour demand.

Exhibit 69: Achievable Potential Peak Demand Savings for Residential Union Gas Service Territory (2026)

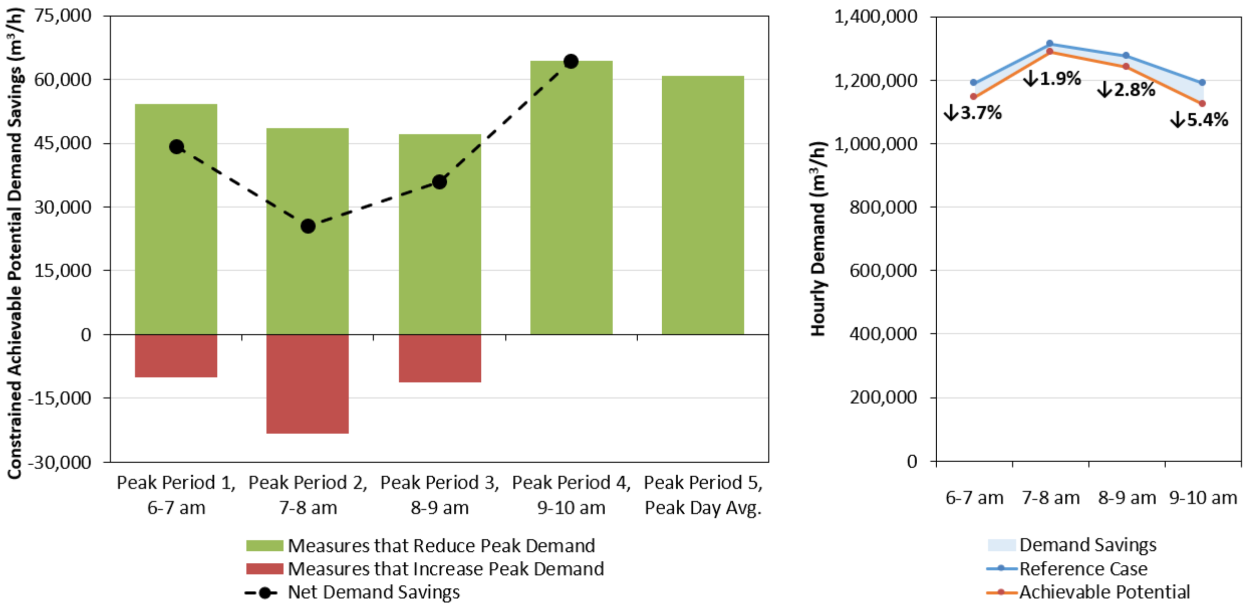


Exhibit 70 presents the residential Union Gas achievable potential demand savings without thermostat measures. As shown, without the impact of the thermostat measures, the natural gas peak demand can be reduced during the peak hour (7-8 a.m.) by 3.7% by 2026, or from approximately 1.31 million m^3 to 1.27 million m^3. The exhibit shows that the demand savings are more evenly spread out during morning lift period, with highest demand savings occurring during peak period #1 (6-7 a.m.) rather than peak period #4 (8-9 a.m.) with the thermostat measures. This is due to the positive demand impacts of the thermostat measures in peak period #4, which are removed when the thermostat measures are excluded entirely. Without the impact of the thermostat measures, the peak hourly demand savings for the peak period of interest (7-8 a.m.) is significantly higher as compared to the same hour in Exhibit 69.

Exhibit 70: Achievable Potential Peak Demand Savings (excluding thermostat measures) for Residential Union Gas Service Territory (2026)

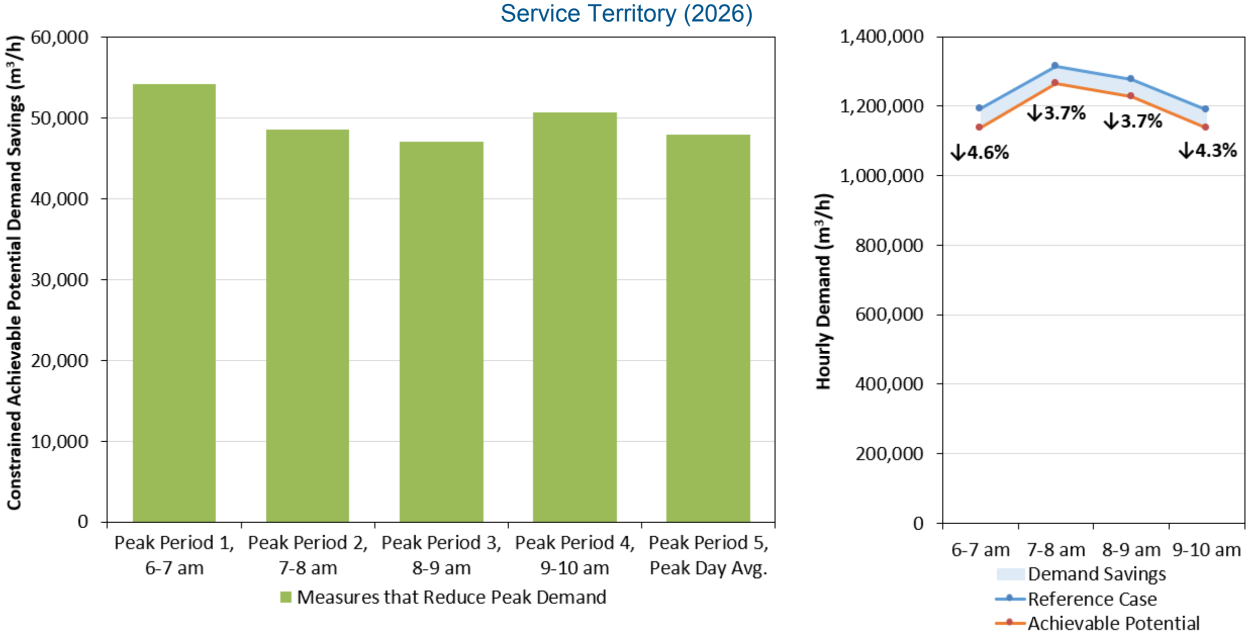


Exhibit 71 provides a comparison of the relative contribution to peak hour savings, annual savings, and reference case peak hour demand for the residential sub-sectors in the Union Gas service territory. This exhibit does not include the impact of thermostat measures, which increase the peak hour demand. This exhibit provides insight into whether or not any particular sub-sectors have a greater impact on demand savings during the peak hour. As shown, the significance of pre-1996 homes is slightly higher for peak hour demand savings than for annual savings. The pre-1996 homes account for 64% of annual savings and 66% of peak hour demand savings. The contribution of low-income dwellings to peak hour demand savings and to annual savings is the same, at 29%.

Post-1996 homes are less important from a peak hour demand perspective since they account for 5% of peak hour demand savings and 7% of annual savings. Post-1996 homes achieve a lower proportion of their energy savings during the peak hour demand period due to their better thermal envelope. The exhibit also shows that low-income homes represent a disproportionately large share of peak hour savings relative to the reference case peak hour demand (representing 21% of reference case peak hour demand and 29% of the achievable peak hour demand savings).

Exhibit 71: Achievable Potential – Relative Contribution to Peak Hour Savings, Annual Savings, and Reference Case Peak Hour Demand by Sub-sector for Residential Union Gas Service Territory (2026)

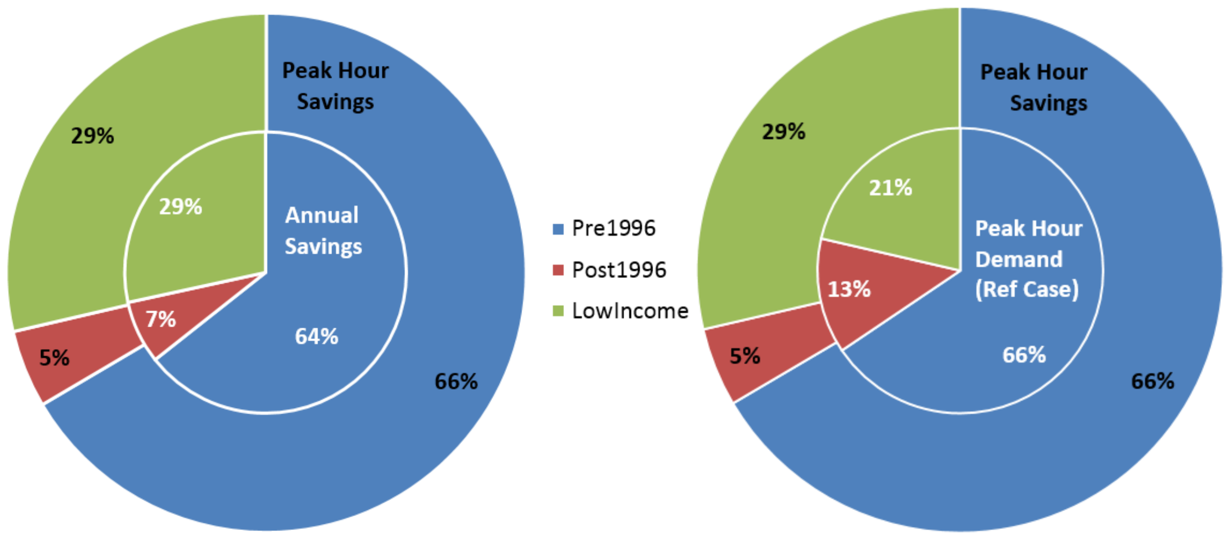


Exhibit 72 provides a comparison of the relative contribution to peak hour demand savings, annual savings, and reference case peak hour demand for the residential end-uses in the Union Gas service territory. This pie chart on the left provides insight into whether or not any particular end-use has a greater impact on peak hour demand savings than annual savings. Space heating gas savings are concentrated during the peak hour (contributing to 95% of overall peak hour demand savings), while DHW makes a smaller relative contribution (5% of overall peak hour demand savings). However, it is important to note that DHW demand is not very focused on the peak hour period, as demonstrated by the fact that DHW accounts for 21% of annual savings but only 11% of reference case peak hour demand. The pie chart on the right also shows that the space heating end-use also has the greatest potential for peak hour demand savings in comparison to its reference case peak hour demand (space heating makes up 89% of the reference case peak hour demand but 95% of peak hour demand savings).

Exhibit 72: Achievable Potential – Relative Contribution to Peak Hour Savings, Annual Savings, and Reference Case Peak Hour Demand by End-Use for Residential Union Gas Service Territory (2026)

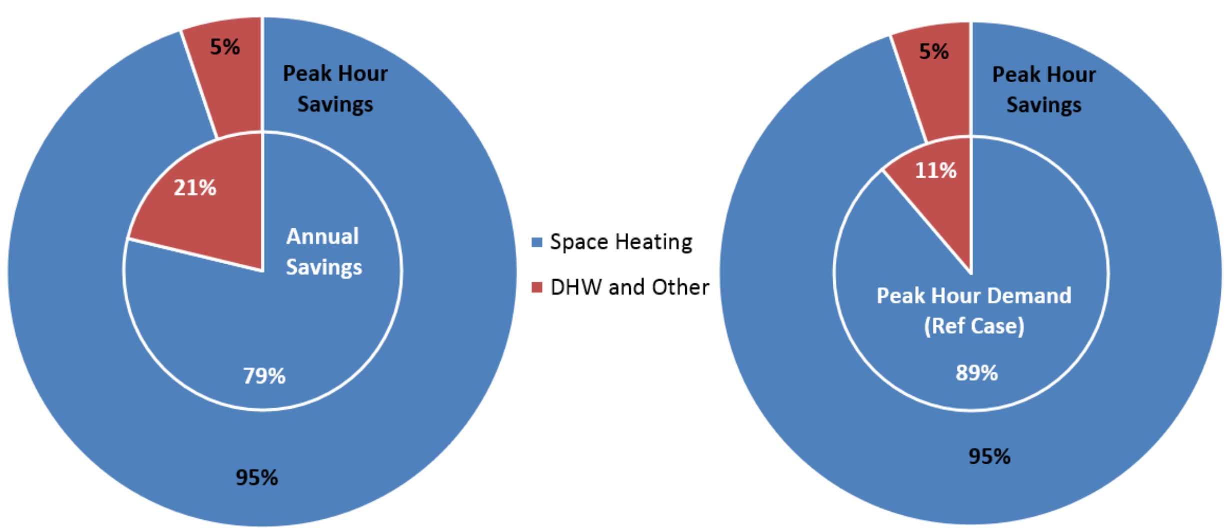
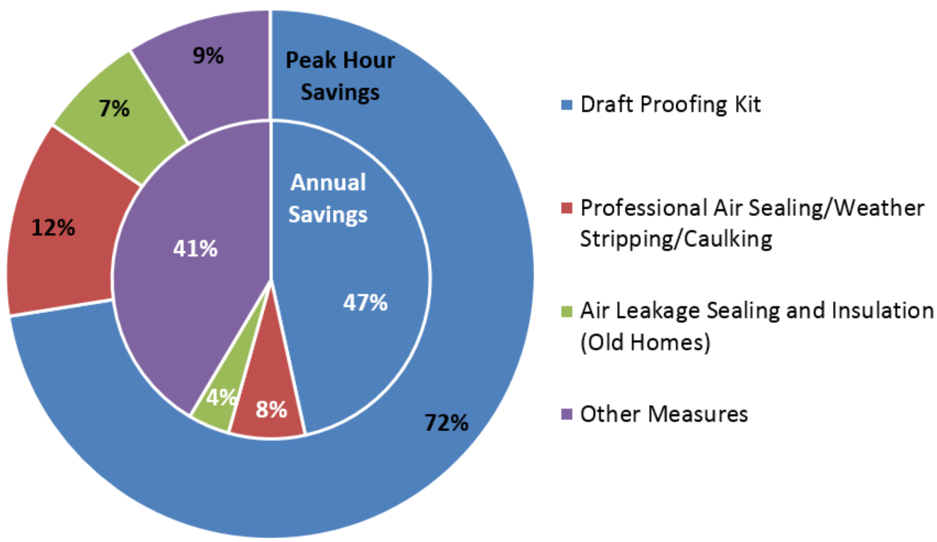


Exhibit 73 provides a comparison of the relative contributions to the 2026 peak hour demand savings and annual consumption savings for the residential measures in the Union Gas service territory. The exhibit does not include the impact of thermostat measures since they lead to increases in peak hour demand. The exhibit provides insight into whether or not any particular measures have a greater impact on achievable potential demand savings during the peak hour.

The exhibit shows that building envelope measures account for the greatest portion of the achievable potential peak hour demand savings, led by the draft proofing kit measure (72% of the savings). This is followed by the professional air sealing/weather stripping/ caulking measure and the air leakage sealing and insulation measure, which account for 12% and 7% of achievable potential peak hour demand savings, respectively. The exhibit also shows that envelope measures have a disproportionately large impact on peak hour demand savings relative to their annual savings.

Exhibit 73: Achievable Potential – Relative Contribution to Peak Hour Demand Savings and Annual Savings by Measure for Residential Union Gas Service Territory (2026)



3.3 Commercial Sector Results

This section summarizes the commercial sector achievable potential peak demand savings analysis results. The results are presented separately for the Gas Utilities and results are further segmented based on the peak period of interest, end-use categories, sub-sectors, and achievable DSM measures.

3.3.1 Enbridge

Exhibit 74 provides a comparison of the commercial sector achievable potential peak period demand savings across five peak periods for all of Enbridge's service territory. As shown, the overall commercial sector peak period savings occurs during peak period #1 (6-7 a.m.), followed by peak period #2 (7-8 a.m.). With the adoption of all achievable measures in the Enbridge service territory for the commercial sector, natural gas demand during the peak hour (7-8 a.m.) could potentially decrease by 3.9% by 2026, or from a projected reference case peak hour demand of 2.50 million m^3 to an achievable potential peak hour demand of 2.40 million m^3. This exhibit also illustrates that DSM is not expected to shift the timing of peak hour demand.

Exhibit 74: Achievable Potential Peak Demand Savings for Commercial Enbridge Gas Service Territory (2026)

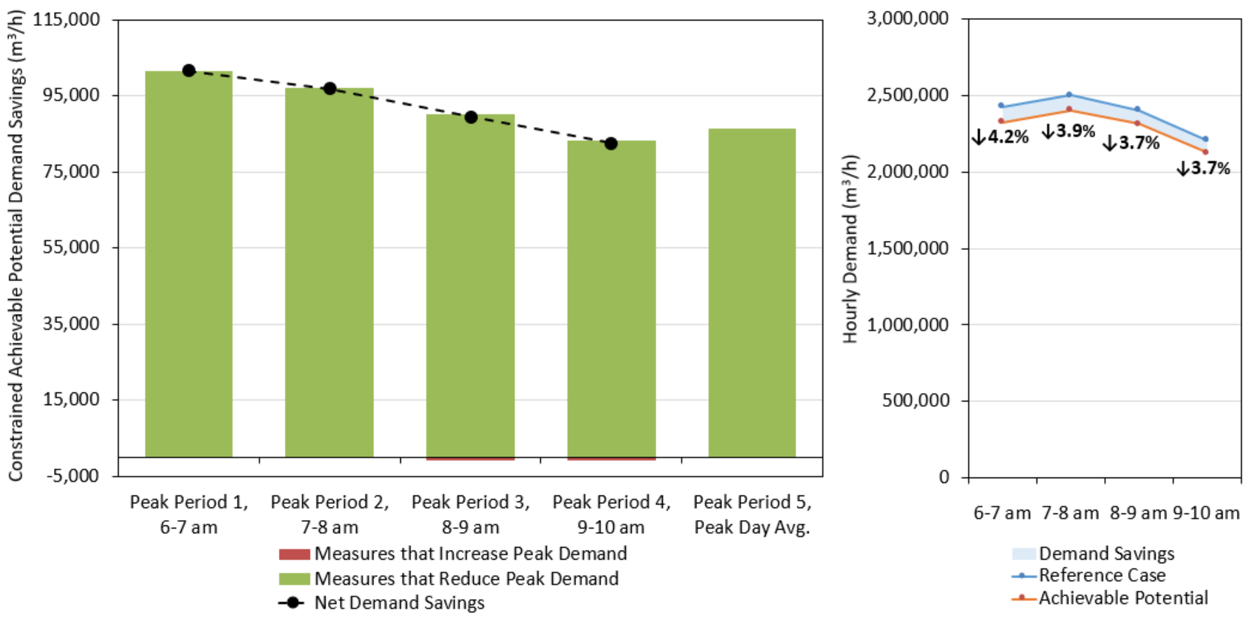


Exhibit 75 presents the commercial Enbridge Gas achievable potential demand savings without thermostat measures, which increase peak demand. As shown, without the impact of the thermostat measures, there is a very minor change in the peak demand savings potential. The natural gas peak demand can be reduced during the peak hour (7-8 a.m.) by 3.9% by 2026, or from approximately 2.50 million m^3 to 2.40 million m^3.

Exhibit 75: Achievable Potential Peak Demand Savings (excluding thermostat measures) for Commercial Enbridge Gas Service Territory (2026)

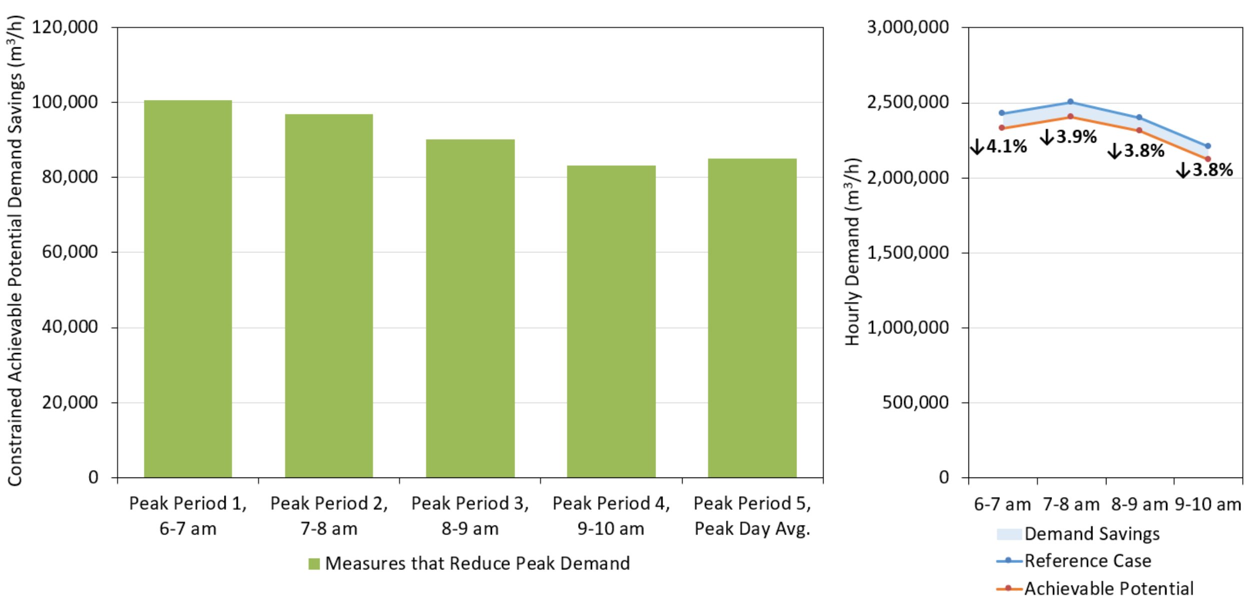


Exhibit 76 provides a comparison of the relative contribution to peak hour demand savings, annual savings, and reference case peak hour demand for the commercial sub-sectors in

Enbridge's service territory. The exhibit does not include the impact of thermostat measures. This exhibit provides insight into whether or not any particular sub-sectors have a greater impact on savings during the peak hour. There are some differences that can be noted between the level of contribution to annual savings and peak hour demand savings.

Offices are shown to be more important from a peak hour demand savings perspective compared to annual savings (23% vs. 18%). As illustrated in the chart on the right, apartment (low-income) buildings have a relatively larger share of peak hour savings potential compared to the reference case peak demand in this sub-sector (i.e., low-income apartments only make up 4% of total reference case peak hour demand, but 9% of total peak hour demand savings).

Exhibit 76: Achievable Potential – Relative Contribution to Peak Hour Demand Savings, Annual Savings, and Reference Case Peak Hour Demand by Sub-sector for Commercial Enbridge Gas Service Territory (2026)

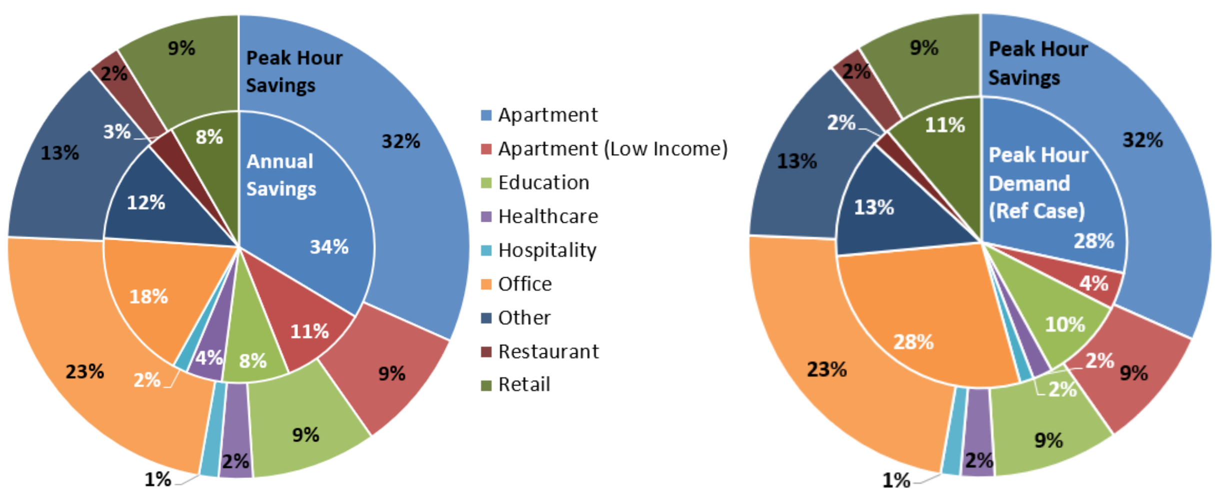


Exhibit 77 provides a comparison of the relative contribution to peak hour demand savings, annual savings, and reference case peak hour demand for the commercial end-uses in Enbridge's service territory. The exhibit provides insight into whether or not any particular end-use has a greater impact on peak hour demand savings than annual savings. Space heating is quite important from a peak hour demand savings perspective (contributing to 88% of peak hour demand savings), while DHW makes a smaller relative contribution to peak hour demand savings (contributing to 12% of peak hour demand savings).

It is also important to note that DHW demand is not very focused on the peak hour period, as demonstrated by the fact that DHW accounts for 27% of annual savings but only 8% of reference case peak hour demand. Although space heating gas savings are most concentrated during the peak hour, the pie chart on the right shows that the DHW and other end-use has the greatest potential for peak hour demand savings among all end-uses in comparison to its reference case peak hour demand (i.e., DHW and other only make up 8% of the reference case peak hour demand but 12% of peak hour demand savings).

Exhibit 77: Achievable Potential – Relative Contribution to Peak Hour Demand Savings, Annual Savings, and Reference Case Peak Hour Demand by End-Use for Commercial Enbridge Gas Service Territory (2026)

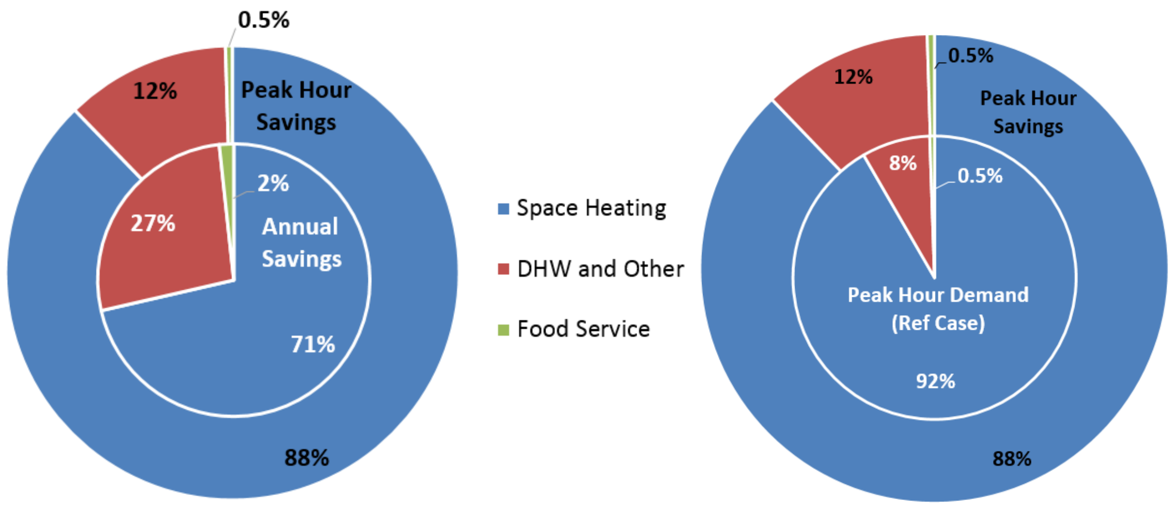
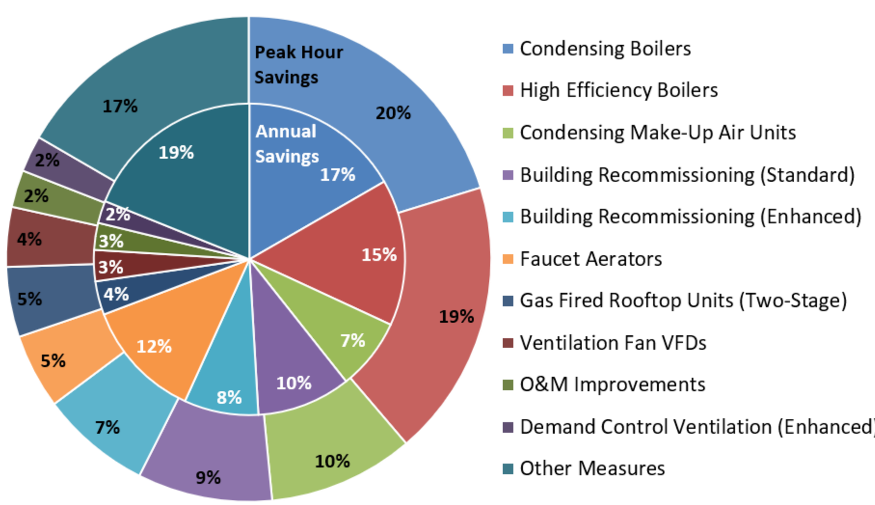


Exhibit 78 provides a comparison of the relative contributions to the 2026 peak hour demand savings and annual consumption savings for the commercial measures in Enbridge's service territory. This exhibit does not include the impact of thermostat measures, which increases the peak demand. The exhibit provides insight into whether or not any particular measures have a greater impact on achievable potential peak hour demand savings. This exhibit shows that several measures, mainly space heating equipment and envelope measures, are more important on a peak hour demand savings basis compared to annual savings. For example, condensing boilers make up 17% of annual savings but 20% of the peak hour demand savings. Conversely, savings for faucet aerators are less focused on the peak demand hour.

Exhibit 78: Achievable Potential – Relative Contribution to Peak Hour Savings, and Annual Savings by Measure for Commercial Enbridge Gas Service Territory (2026)



3.3.2 Union Gas

Exhibit 79 provides a comparison of the commercial sector achievable potential peak period demand savings across five peak periods for the Union Gas service territory. As shown, the highest residential sector peak savings occurs during peak period #1 (6-7 a.m.), followed very closely by peak period #2 (7-8 a.m.). With the adoption of all achievable measures in the Union Gas service territory for the commercial sector, natural gas demand during the peak hour (7-8 a.m.) could potentially decrease by 4.1% by 2026, or from a projected reference case peak hour demand of 1.27 million m^3 to an achievable potential peak hour demand of 1.22 million m^3. This exhibit also illustrates that DSM is not expected to shift the timing of peak hour demand.

Exhibit 79: Achievable Potential Peak Hour Demand Savings for Commercial Union Gas Service Territory (2026)

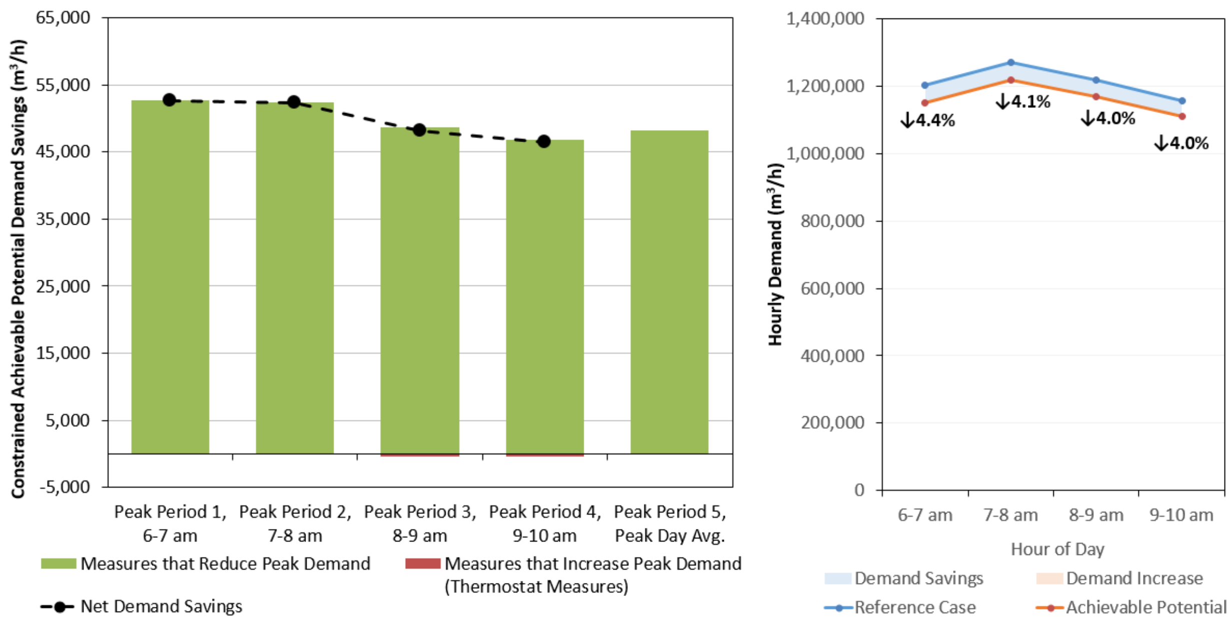


Exhibit 80 presents the commercial Union Gas achievable potential peak demand savings without thermostat measures, which increase peak demand. As shown, without the impact of the thermostat measures, there is a very minor change in the peak hour demand savings potential for each period. The natural gas peak demand can be reduced during the peak hour (7-8 a.m.) by 4.1% by 2026, or from approximately 1.27 million m^3 to 1.22 million m^3.

Exhibit 80: Achievable Potential Demand Savings (excluding thermostat measures) for Commercial Union Gas Service Territory (2026)

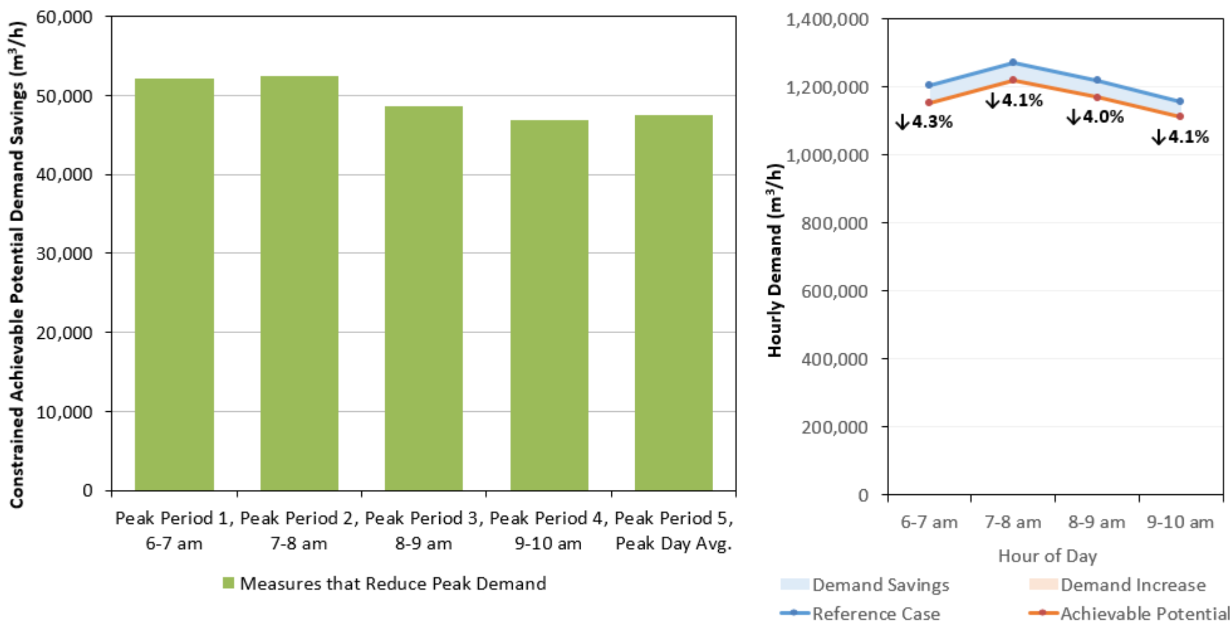


Exhibit 81 provides a comparison of the relative contribution to peak hour demand savings, annual savings, and reference case peak hour demand for the commercial sub-sectors in Union Gas' service territory. This exhibit does not include the impact of thermostat measures. This exhibit provides insight into whether or not any particular sub-sectors have a greater impact on savings during the peak hour. There are some differences that can be noted between the level of contribution to annual savings and peak hour demand savings.

The Other sub-sector is shown to be more important from a peak hour demand savings perspective compared to annual savings (39% vs. 36%). As illustrated in the chart on the right, apartments (low-income) and other buildings have a relatively larger share of peak hour demand savings potential compared to the reference case peak hour demand in this sub-sector (i.e., low-income apartments make up 3% of total reference case peak hour demand but 5% of total peak hour demand savings). Similarly, the Other sub-sector makes up 32% of the reference case peak hour demand, and 39% of the peak hour demand savings.

Exhibit 81: Constrained Achievable Potential – Relative Contribution to Peak Hour Demand Savings, Annual Savings, and Reference Case Peak Hour Demand by Sub-sector for Commercial Union Gas Service Territory (2026)

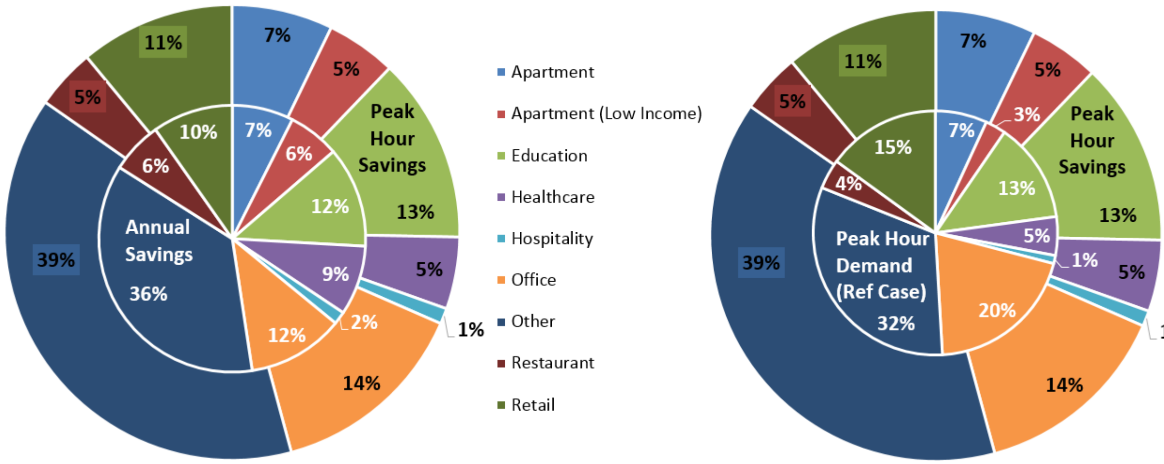


Exhibit 82 provides a comparison of the relative contribution to peak hour demand savings, annual savings, and reference case peak hour demand for the commercial end-uses in Union Gas' service territory. The exhibit provides insight into whether or not any particular end-use has a greater impact on peak hour demand savings than annual savings. Space heating is quite important from a peak hour demand savings perspective (contributing to 89% of peak hour demand savings), while DHW makes a smaller relative contribution (10% of peak hour demand savings).

It is also important to note that DHW demand is not very focused on the peak hour period, as demonstrated by the fact that DHW accounts for 27% of annual savings but only 7% of reference case peak hour demand. Although space heating gas savings are most concentrated during the peak hour, the pie chart on the right shows that the DHW and other end-use has the greatest potential for savings among all end-uses in comparison to its reference case peak hour demand (i.e., DHW and other only make up 7% of the reference case peak hour demand but 10% of peak hour demand savings).

Exhibit 82: Achievable Potential – Relative Contribution to Peak Hour Demand Savings, Annual Savings, and Reference Case Peak Hour Demand by End-Use for Commercial Union Gas Service Territory (2026)

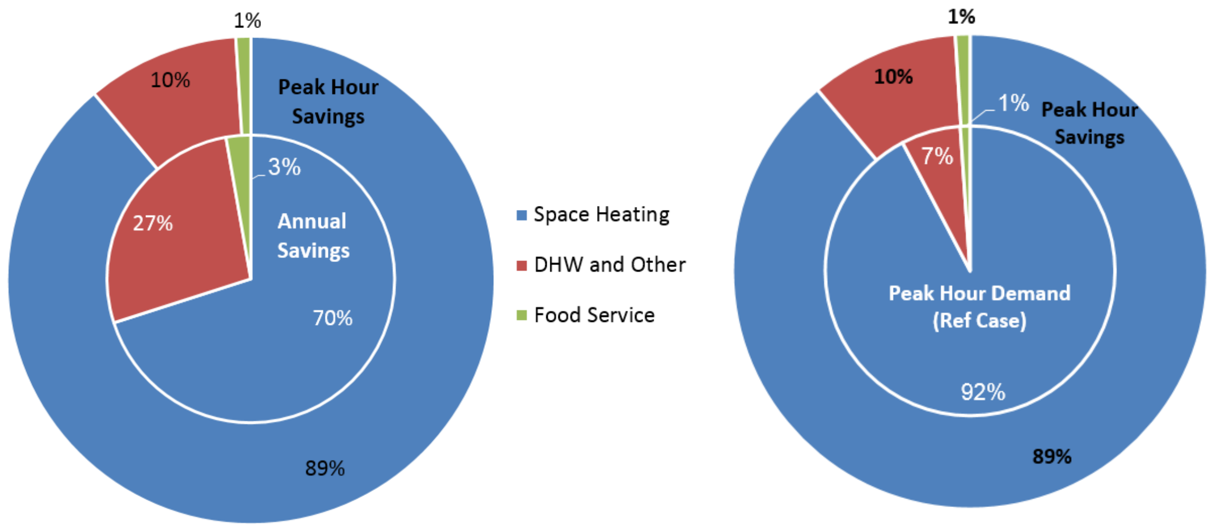
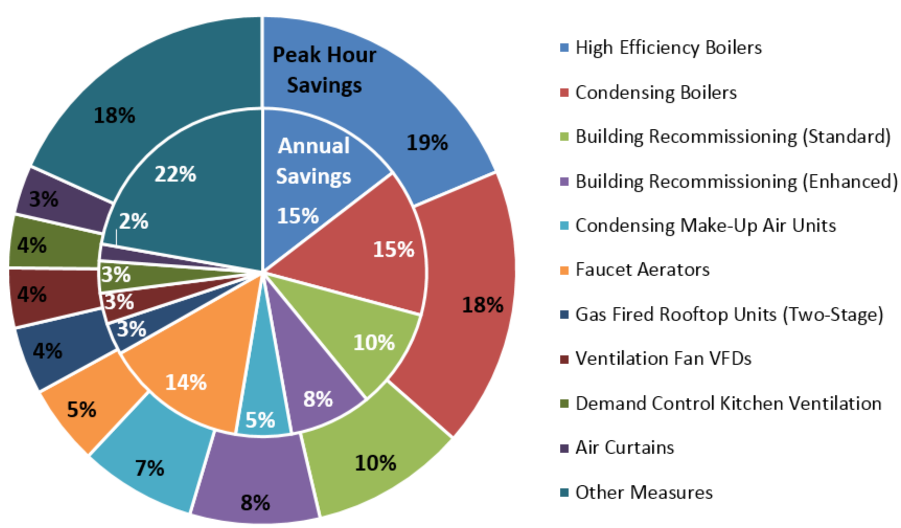


Exhibit 83 provides a comparison of the relative contributions to the 2026 peak hour demand savings and annual consumption savings for the commercial measures in Union Gas' service territory. The exhibit does not include the impact of thermostat measures, which increases the peak demand. The exhibit provides insight into whether or not any particular measures have a greater impact on achievable potential savings during the peak hour. This exhibit shows that several measures, mainly space heating equipment and envelope measures, are more important on a peak hour demand savings basis compared to annual savings. For example, condensing boilers make up 15% of annual savings, but account for 19% of the peak hour demand savings. Conversely, faucet aerators savings are less focused on the peak hour.

Exhibit 83: Achievable Potential – Relative Contribution to Peak Hour Demand Savings, and Annual Savings by Measure for Commercial Union Gas Service Territory (2026)



3.4 Industrial Sector Results

This section summarizes the industrial sector achievable potential peak demand savings analysis results. The results are presented separately for the Gas Utilities and results are further segmented based on the peak period of interest, end-use categories, sub-sectors, and achievable DSM measures.

3.4.1 Enbridge

Exhibit 84 provides a comparison of the five peak periods for the Enbridge service territory, showing how the constrained achievable potential demand savings are distributed among sub-sectors. As shown, the highest peak period demand savings occur during peak period #3 (8-9 a.m.), with peak period #2 (7-8 a.m.) very close behind. The relative contribution of individual sub-sectors to peak period demand savings remains fairly consistent throughout the morning lift. During the peak demand hour (6-7 a.m.), manufacturing facilities account for 68% of achievable potential peak hour demand savings, followed by heavy process industries at 19%, mineral processing industries at 6%, greenhouses and agriculture at 5%, and resource extraction industries at 1%.

The adoption of all achievable measures in the Enbridge service territory for the industrial sector could potentially reduce natural gas demand during the peak demand hour (7-8 a.m.) by 17.1% by 2026, or from a projected reference case peak hour demand of 0.36 million m^3 to an achievable potential peak hour demand of 0.30 million m^3. This exhibit also illustrates that DSM is not expected to shift the timing of peak hour demand.

Exhibit 84: Achievable Potential Demand Savings for Industrial Enbridge Gas Service Territory (2026)

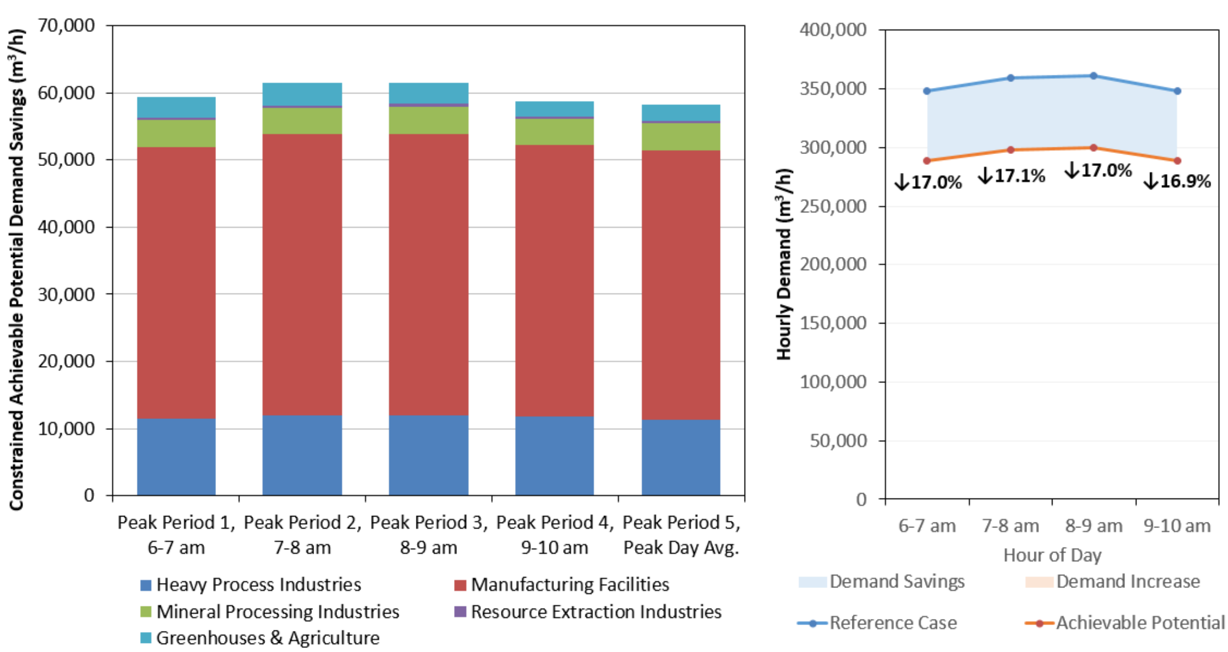


Exhibit 85 provides a comparison of the relative contribution to peak hour demand savings, annual savings, and reference case peak hour demand for the industrial sub-sectors in Enbridge's service territory. The exhibit provides insight into whether or not any particular sub-sectors have a greater impact on savings during the peak hour. As the exhibit shows, the manufacturing sub-sector is the most important from a peak hour demand savings perspective (68% share of peak hour demand savings vs. 54% share of annual savings), while heavy process industries have the lowest relative impact (20% share of peak hour demand savings vs. 30% share of annual savings).

Exhibit 85: Achievable Potential – Relative Contribution to Peak Hour Demand Savings, Annual Savings, and Reference Case Peak Hour Demand by Sub-sector for Industrial Enbridge Gas Service Territory (2026)

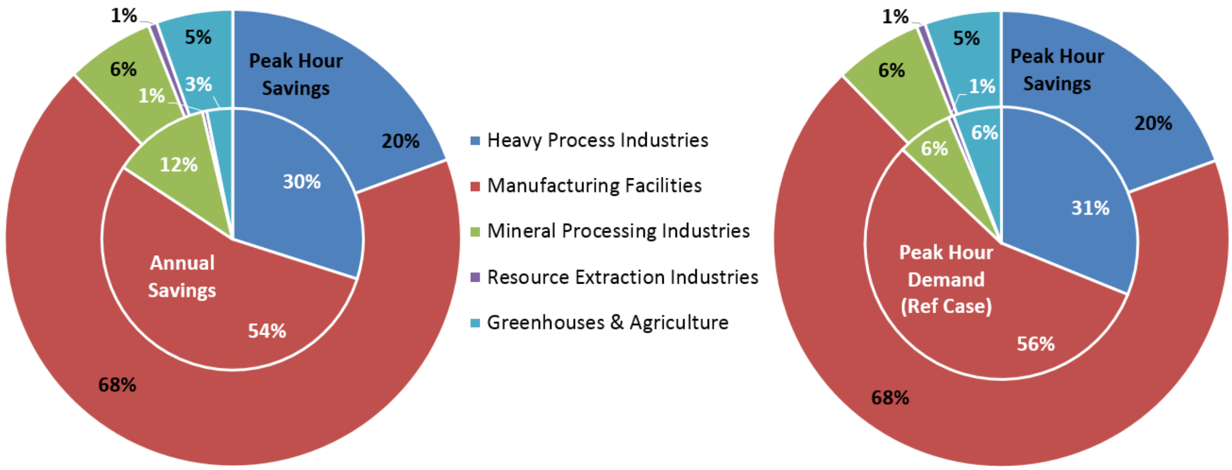


Exhibit 86 provides a comparison of the relative contribution to peak hour demand savings, annual savings, and reference case peak hour demand for the industrial end-uses in the Enbridge service territory. This exhibit provides insight into whether or not any particular end-use has a greater impact on peak hour demand savings than annual savings. The left pie chart shows that HVAC is the most important end-use from a peak hour demand savings perspective (67% share of peak demand savings vs. 26% share of annual savings), while direct heating has the lowest relative impact (21% share of peak hour demand savings vs. 50% share of annual savings). Based on the pie chart on the right, the HVAC and other end-use also has the largest achievable peak hour demand savings potential relative to its reference case peak hour demand.

Exhibit 86: Achievable Potential – Relative Contribution to Peak Hour Demand Savings, Annual Savings, and Reference Case Peak Hour Demand by End-Use for Industrial Enbridge Gas Service Territory (2026)

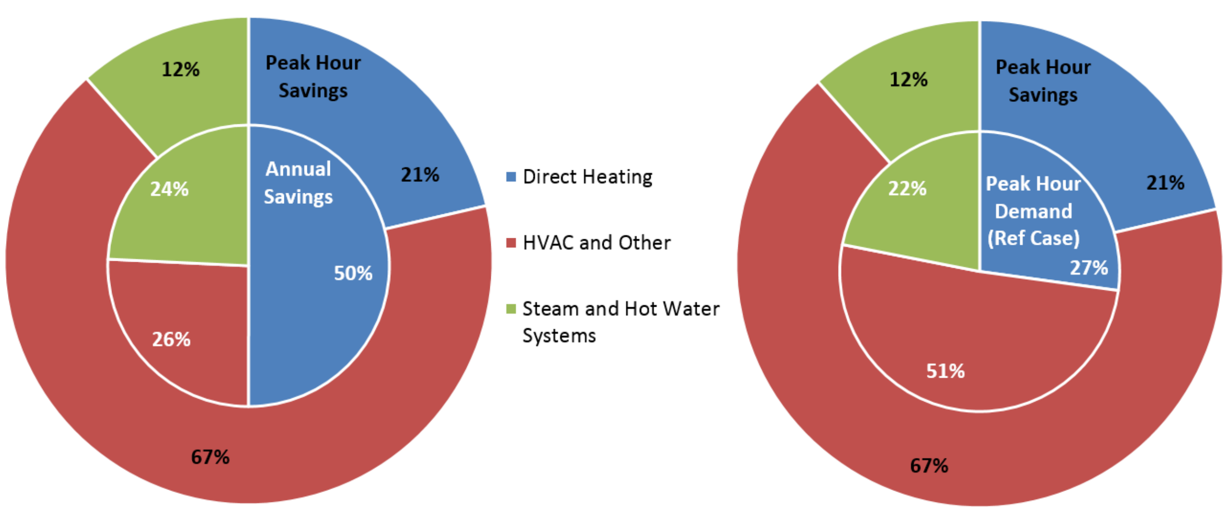
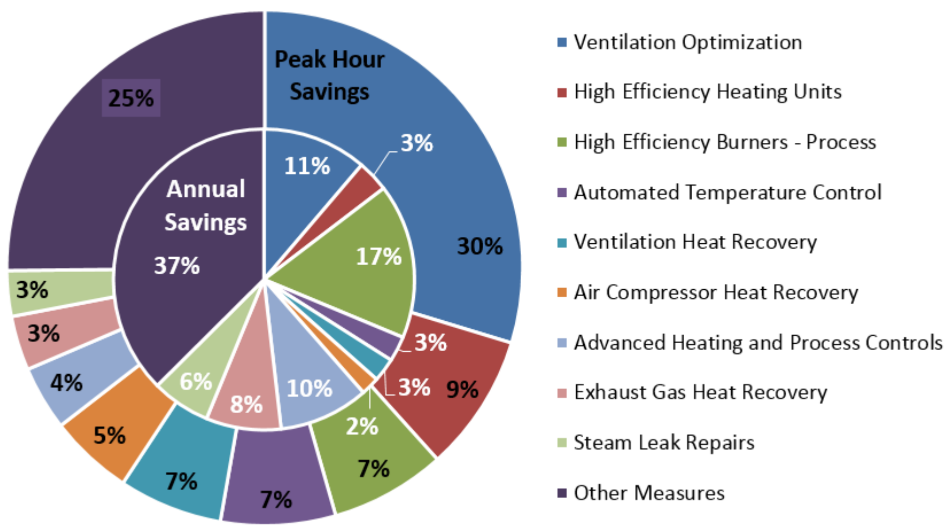


Exhibit 87 provides a comparison of the relative contributions to the 2026 peak hour demand savings and annual consumption savings for the industrial measures in the Enbridge service territory. The exhibit provides insight into whether or not any particular measures have a greater impact on achievable potential savings during the peak hour. Most of the measures with the highest peak hour demand savings potential are those in the HVAC and other end-use categories. The exhibit shows that ventilation optimization is the most important measure from a peak hour demand savings perspective (30% share of peak hour demand savings vs. 11% share of annual savings), followed by high-efficiency heating units (9% of peak hour demand savings), high-efficiency process burners, automated temperature controls, and ventilation heat recovery (each at 7% of peak hour demand savings).

Exhibit 87: Achievable Potential – Relative Contribution to Peak Hour Demand Savings, and Annual Savings by Measure for Industrial Enbridge Gas Service Territory (2026)



3.4.2 Union Gas

Exhibit 88 provides a comparison of the five peak periods for Union Gas' service territory, showing how the constrained achievable potential demand savings are distributed among sub-sectors. As shown, the highest peak period savings occur during peak period #1 (6-7 a.m.), with peak period #2 (7-8 a.m.) close behind. The relative contribution of individual sub-sectors to peak hour demand savings remains fairly consistent throughout the morning lift. During the peak demand hour (7-8 a.m.), manufacturing facilities account for 41% of potential savings, followed by heavy process industries at 25%, greenhouses and agriculture at 15%, resource extraction industries at 15%, and mineral processing industries at 5%.

The adoption of all achievable measures in the Union Gas service territory for the industrial sector could potentially reduce natural gas demand during the peak demand hour (7-8 a.m.) by 10.9% by 2026, or from a projected reference case peak hour demand of 1.22 million m^3 to an achievable potential peak hour demand of 1.09 million m^3. This exhibit also illustrates that DSM is not expected to shift the timing of peak hour demand.

Exhibit 88: Achievable Potential Demand Reduction for Industrial Union Gas Service Territory (2026)

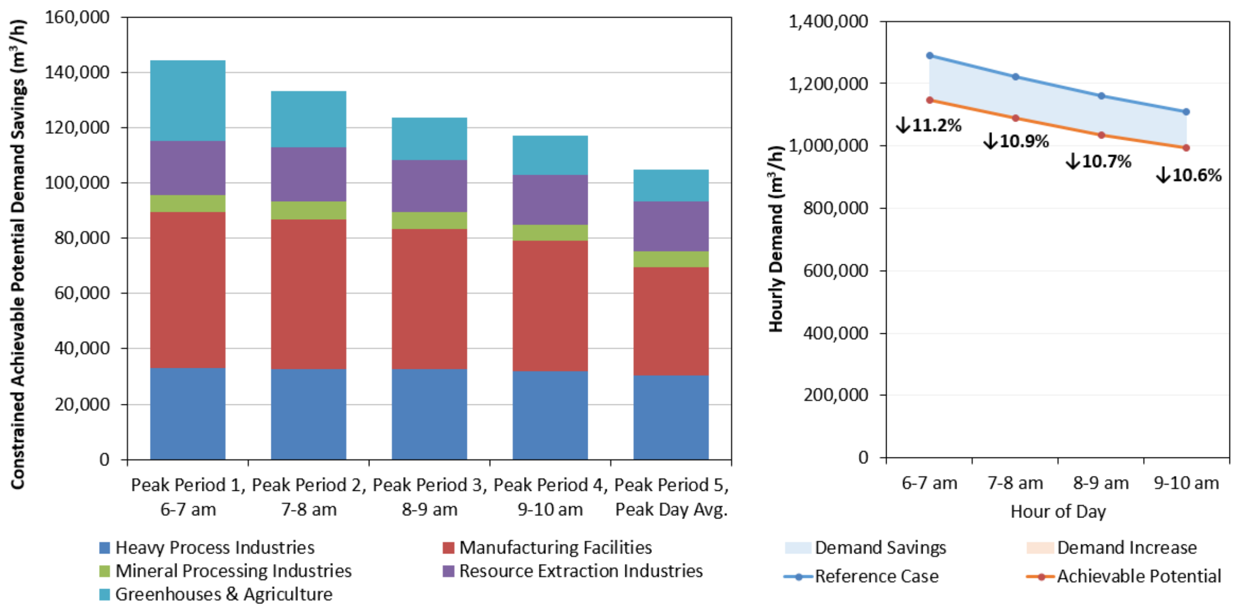


Exhibit 89 provides a comparison of the relative contribution to peak hour demand savings, annual savings, and reference case peak hour demand for the industrial sub-sectors in Union Gas' service territory. This exhibit provides insight into whether or not any particular sub-sectors have a greater impact on savings during the peak hour. As shown, the manufacturing sub-sector is the most important from a peak hour demand savings perspective (40% share of peak hour demand savings vs. 30% share of annual savings), while heavy process industries have the lowest relative impact (25% share of peak hour demand savings vs. 36% share of annual savings). Although savings for mineral processing industries are less concentrated during the peak hour, the pie chart on the right shows that the peak hour demand savings for this sub-sector are important due to the high percentage of peak hour savings for this sub-sector in comparison to its reference case peak hour demand.

Exhibit 89: Achievable Potential – Relative Contribution to Peak Hour Demand Savings, Annual Savings, and Reference Case Peak Hour Demand by Sub-sector for Industrial Union Gas Service Territory (2026)

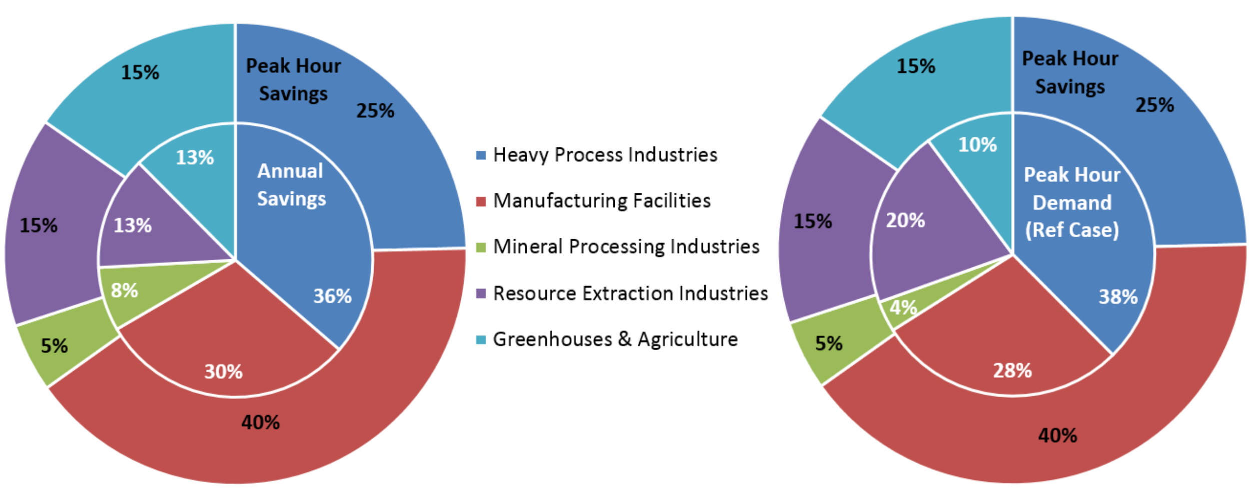


Exhibit 90 provides a comparison of the relative contribution to peak hour demand savings, annual savings, and reference case peak hour demand for the industrial end-uses in the Union Gas service territory. This exhibit provides insight into whether or not any particular end-use has a greater impact on peak hour demand savings than annual savings. The pie chart on the left shows that HVAC is the most important end-use from a peak hour demand savings perspective (51% share of peak hour demand savings vs. 23% share of annual savings), while direct heating has the lowest relative impact (34% share of peak hour demand savings vs. 54% share of annual savings). Based on the right pie chart, the HVAC and other end-use also has the largest achievable peak hour demand savings potential relative to its reference case peak hour demand.

Exhibit 90: Achievable Potential – Relative Contribution to Peak Hour Demand Savings, Annual Savings, and Reference Case Peak Hour Demand by End-Use for Industrial Union Gas Service Territory (2026)

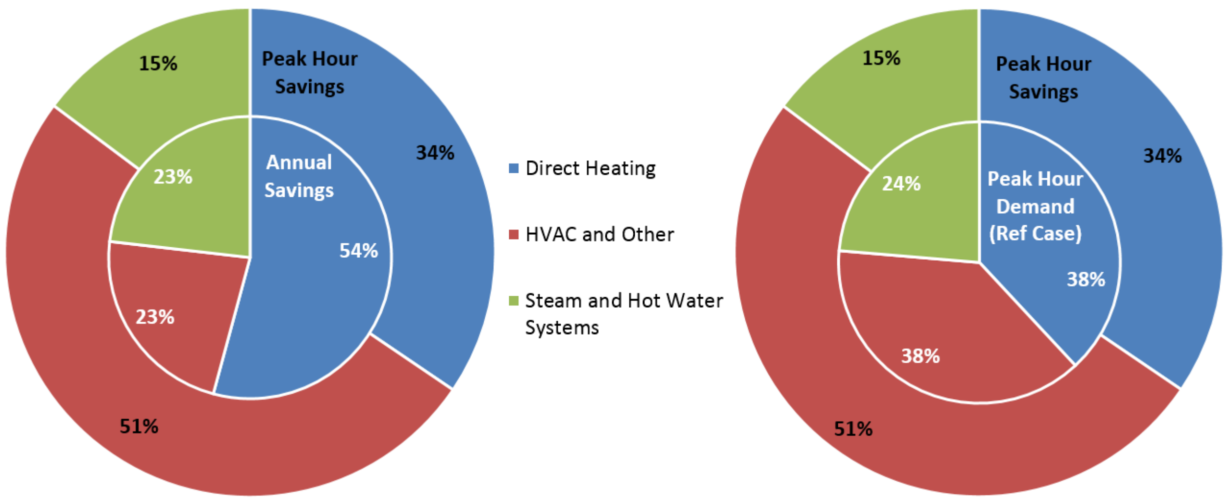
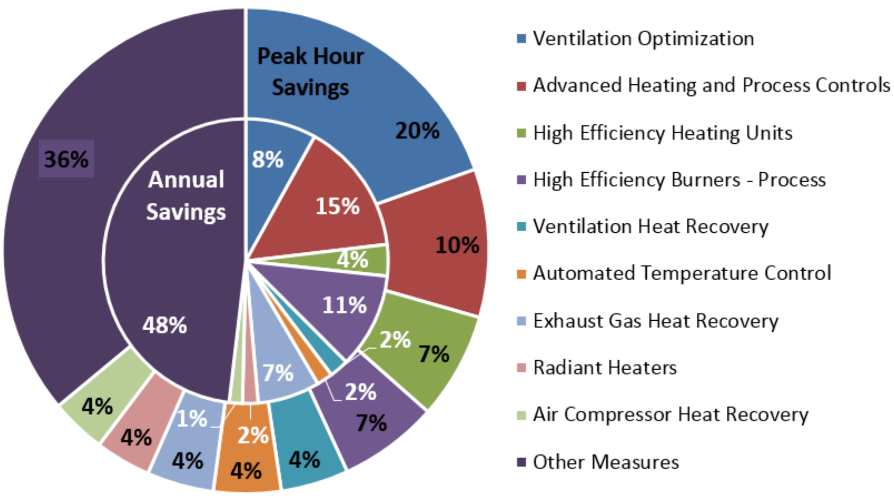


Exhibit 91 provides a comparison of the relative contributions to the 2026 peak hour demand savings and annual consumption savings for the industrial measures in the Union Gas service territory. The exhibit provides insight into whether or not any particular measures have a greater impact on achievable potential peak hour demand savings. Most of the measures with the highest peak hour demand savings potential are those in the HVAC and other end-use categories. The exhibit shows that ventilation optimization is the most important measure from a peak hour perspective (20% share of peak hour demand savings vs. 8% share of annual savings). Advanced heating and process controls is the measure with the next highest impact; however, unlike ventilation optimization which is more important on a peak hour savings basis than annual savings, this measure saves 15% in annual savings but only 10% in peak hour demand savings.

Exhibit 91: Achievable Potential – Relative Contribution to Peak Hour Demand Savings, and Annual Savings by Measure for Industrial Union Gas Service Territory (2026)



4. Summary of Results

ICF's analysis suggests that DSM is not expected to shift the timing of peak hour demand from the current peak period #2 (7-8 a.m.) and it remains the peak period of interest for the overall results. In the comparison of all sectors, the commercial and residential sectors are shown to have DSM measure savings slightly more concentrated during the peak demand hour than the annual savings as compared to the industrial sector. The distribution of savings between the sectors can be summarized as follows:

- For Union Gas, the industrial sector makes up a much higher percentage of total achievable peak hour demand savings at 57% (0.13 million m^3/hr) compared 16% of peak hour demand savings for the commercial sector, and 16% for the residential sector (0.05 million m^3/hr).
- The results for Enbridge indicate that peak hour demand savings are highest for the commercial sector at 47% (0.10 million m^3/hr), followed by the industrial sector at 30% (0.06 million m^3/hr), and the residential sector at 23% (0.05 million m^3/hr).
- For both Gas Utilities, the peak hour demand savings relative to the reference case peak hour demand are highest for the industrial sector.

The broad-based DSM impacts on peak day and peak hour demand savings by sector (residential, commercial, industrial) are summarized below. For each sector, the analysis identified which sub-sectors and end-uses have a larger relative impact on the achievable potential peak demand hour savings.

4.1 Residential Sector Results

The residential sector included all homes except for multi-unit residential buildings (MURBs or apartment buildings, which are considered in the commercial sector). ICF's analysis indicated that the highest achievable potential peak demand savings in the residential sector occurs during peak period #4 (9-10 a.m.) and that adaptive thermostats could lead to an increase in peak demand during the peak hour peak period #2 (7-8 a.m.). While the highest reduction is present in peak period # 4, the most relevant results of the analysis are those pertaining to the peak hour, peak period #2, as demand savings then are the most important in reducing facility investments. Other high-level results for the residential sector analysis include:

- Low-income homes represent a disproportionately large share of peak hour demand savings relative to the reference case peak hour demand due to the age and the nature of the housing stock
- Space heating measures are quite important from a peak demand hour savings perspective since they have both a higher relative impact and a higher savings potential
- The top three residential peak hour demand savings measures are all related to air tightening (building envelope)

4.2 Commercial Sector Results

ICF's analysis indicated that the highest peak demand hour savings potential in the commercial sector occurs during peak period #1 (6-7 a.m.), although the peak hour savings potential during this period is only slightly higher than the peak period of interest peak period # 2 (7-8 a.m.). Other high-level results for the commercial sector analysis include:

- Sub-sectors that are more important from peak hour savings perspective include offices, education, retail, and other
- Low-income apartments have a relatively large peak hour demand savings potential relative to reference case peak hour demand due to the age and the nature of the housing stock
- Space heating is the most important end-use from a peak hour demand savings perspective, but there is also significant potential peak hour demand savings in DHW
- Space heating measures, such as high-efficiency boilers, condensing boilers, and condensing make-up air units (MAUs), are important from a peak hour demand savings perspective.

4.3 Industrial Sector Results

ICF's analysis indicated that the highest achievable potential peak demand savings potential in the industrial sector for Union Gas occurs during peak period # 1 (6-7 a.m.), although the peak hour demand savings potential during this period is only slightly higher than the peak period of interest, the peak hour (7-8 a.m.). The highest achievable potential savings for Enbridge occur in peak period # 3 (8-9 a.m.), which is also slightly higher than the peak hour. Other high-level results for the industrial sector analysis include:

- Manufacturing facilities and greenhouses/agriculture are more important as compared to other industrial customers from a peak hour demand savings perspective.
- Demand savings from mineral processing industries are less concentrated during the peak hour, but are still important due to the high percent of peak hour savings that can be attained.
- The HVAC and other end-use is quite important from a peak demand hour savings perspective since the demand and savings potential is focused on the peak hour.
- Space heating measures are important to consider in the industrial sector as well if the goal is to reduce peak hour demand.

V. Potential for DSM to Impact Facilities Planning

This chapter evaluates the extent to which the DSM measures identified in the previous section can be integrated with the facilities planning process to modify proposed facility investments. ICF reviewed the Gas Utilities' current facility investment plans and compared them to the achievable reductions in demand from DSM. The remainder of the section provides more detail on the three intersections of this study: 1) Broad-based DSM effects on facilities planning; 2) New subdivision and community facilities planning; and 3) Geo-targeted DSM and reinforcement facilities planning.

1. Overview of Potential Avoided Capital Costs from DSM

1.1 Incremental Facility Investments

The Gas Utilities provided ICF with basic information summarizing their current facility investment plans.[109] This information represented the full range of facility investments under consideration by the Gas Utilities (i.e., the information was not intended to represent any specific facility investment plan, or to indicate which plans would be submitted to the Board for approval).

The information provided by the Gas Utilities pertained to both distribution and transmission facility investments within the Utility service territories. All of the facility investments provided by Enbridge were considered to be distribution facility investments, and were planned based on peak hour capacity requirements. The facility investments provided by Union Gas included both distribution and transmission projects. The distribution projects were developed based on peak hour capacity requirements, while the transmission projects were developed based on the characteristics of the individual project, and considered both peak hour and peak period (up to peak day) requirements specific to the individual project.

For the purposes of this analysis, ICF treated all of the projects provided by Union Gas and Enbridge as driven by the peak hour requirements. ICF believes that the broad results, defined as part of this analysis, are applicable to both distribution and transmission infrastructure. However, application of the results to specific transmission projects where capacity requirements are based on a period longer than the peak hour would benefit from an assessment of DSM potential over the specific planning period relevant for each project.

ICF also treated all of the facility investment plans as driven entirely by growth in natural gas demand, even though it is understood that some projects are driven in part by factors other than demand growth, including system resiliency, reliability, and longer term system functionality, among other factors. As a result, the analysis included in this report overstates the benefits of reducing demand through DSM relative to the costs of these projects. These incremental benefits would need to be accounted for when determining whether or not DSM would make sense as an approach to reducing the project investment.

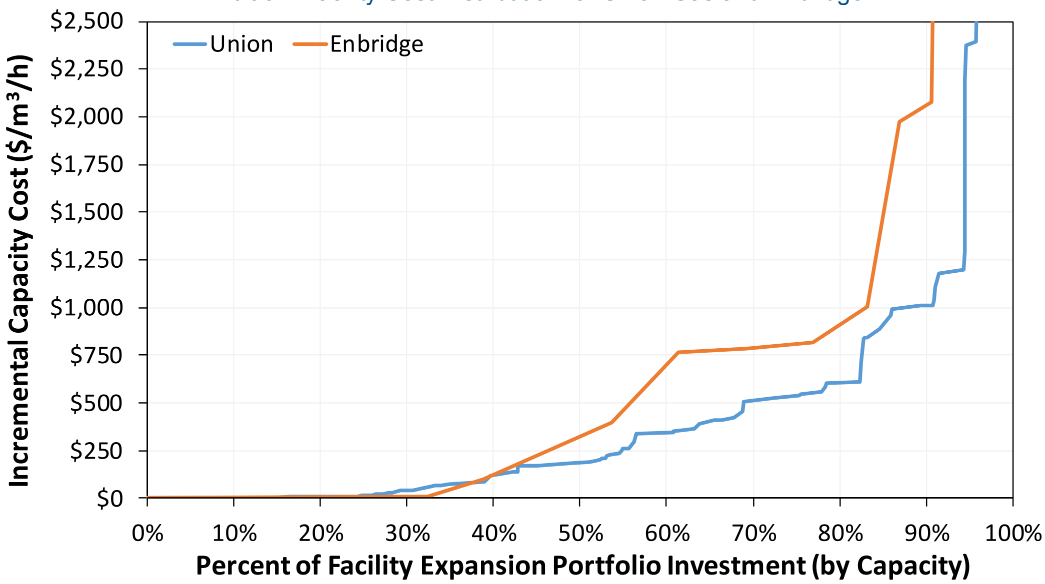
[109] This information provided by the Gas Utilities did not include any of the large transmission systems (e.g. Dawn Parkway).

ICF used the information provided by the Gas Utilities to estimate and compare the incremental costs of added capacity across the various facility investment plans. In cases where the incremental capacity provided by a specific facility investment was unavailable, ICF estimated the incremental capacity as that required to serve the anticipated demand until the next planned facility investment on the same network, or until the end of the planning window. The costs per unit peak demand (i.e. $ per m^3/h) for the facility investments vary widely depending on the specifics of each project, including the type and location of the project, and the amount of unused capacity associated with the facility. Exhibit 92 presents each utility's distribution of facility investments by cost of incremental capacity, essentially a supply curve for incremental distribution capacity to meet customer needs.

Exhibit 92 shows that:

- For both Gas Utilities, about 40% of the facilities expansion capacity is available at less than $100 per m^3/h
- For Union Gas, nearly 70% of facilities expansion capacity is available for less than $500 per m^3/h, while for Enbridge about 55% of facilities expansion capacity is available for less this price

Exhibit 92: Facility Cost Distribution for Union Gas and Enbridge

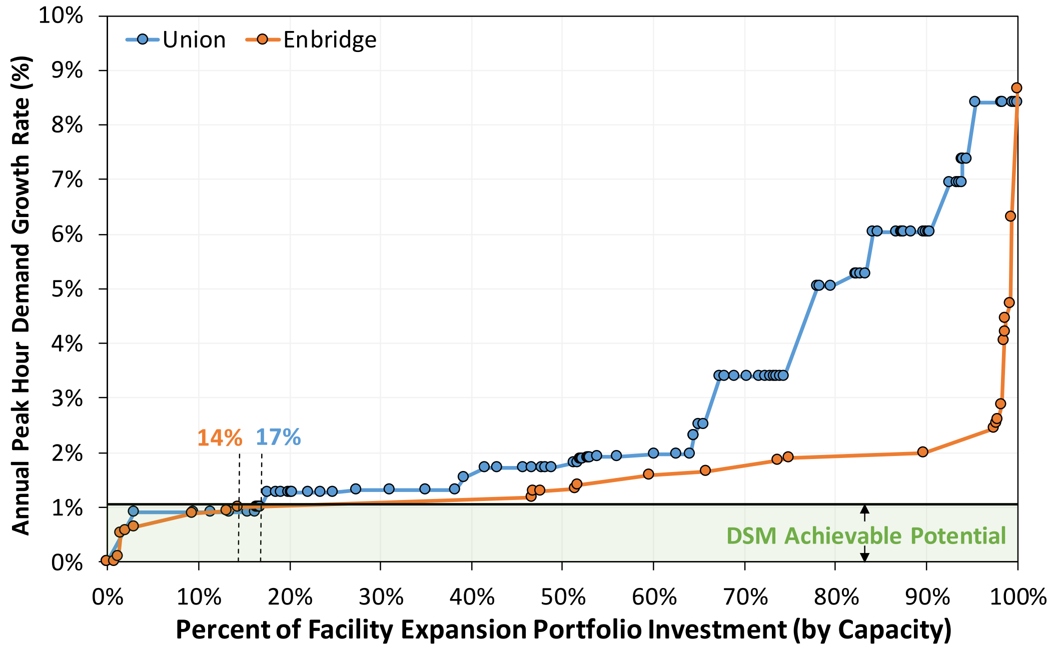


1.2 Demand Growth Rates

ICF's analysis of DSM potential indicates that the cost of geo-targeted DSM programs increases as the desired penetration rate for the program increases, and that there is likely to be a maximum cost-effective level of DSM program penetration. ICF's analysis also suggests that, on average, the achievable potential for peak hour demand savings is in the range of 1.2% of peak hour demand per year. As summarized in Exhibit 93, most of the Gas Utilities' planned facility investments are required due to growth rates that exceed this threshold.[110] ICF's analysis of the Gas Utilities' initial facility investment plan data revealed that, when measured by the amount of incremental capacity being added, only about 17% of Union Gas' planned facility investments are being driven by demand growth rates below 1.2% annual peak hour demand growth, while approximately 14% of Enbridge's planned facility investments fall below this critical level of growth. In essence, before cost considerations, DSM could potentially avoid a little less than 20% of the Gas Utilities' planned investments.

For the other 80% of the Gas of Utilities' planned investments, that are designed to meet load growth in in regions where demand is projected to grow at faster than about 1.2% per year, DSM would not be sufficient to avoid the planned investment, but might be sufficient to delay the planned investment by one or more years, depending on the number of years that the DSM program is implemented prior to the need for the additional capacity.

Exhibit 93: Planned Capacity Additions (m^3/h) by Regional Growth Rate



2. Intersection 1: Broad-Based DSM and Facilities Planning

This section covers the first area of intersection for this study:

- **Intersection 1:** Broad-Based DSM Impacts on Facilities Planning (Passive Deferral)

All DSM programs have the potential to impact peak hourly and peak daily demand and to change the need for new facility investments regardless of whether or not the programs are

[110] Generally, investments in new facilities are more likely to be required in areas with fast growing demand. Hence the average rate of growth in areas where new infrastructure projects have been planned tends to be significantly higher than the average growth rate on the overall system.

specifically designed to reduce peak demand.[111] This is referred to as passive deferral of facility investments.

Passive deferral of facility investments based on broad-based DSM requires two basic components to be accurately captured in the facilities planning process:

- Use of appropriate reduced facility investment cost estimates that fully value the potential costs and benefits associated with the reduction of facility investments through DSM programs
- Accurate consideration of the expected impacts of energy-efficiency measures and DSM programs on the peak hour and peak day demand forecasts used to evaluate the need for facility investments

2.1 Broad-Based DSM Supply Curve Analysis Approach

ICF constructed broad-based DSM supply curves to show the annual DSM program costs required to achieve peak hour demand savings through DSM in each utility service territory. The peak hour demand savings due to DSM were presented in Section IV of this report. As discussed previously, these estimates of peak hour demand savings are based on modelling results and are segmented by region, sub-sector, end-use categories, and measure types. It is important to note that there is a difference in the achievable potential scenarios that were leveraged for the peak hour demand savings presented in Section IV compared to the achievable potential presented in this section. Section IV presented the constrained achievable potential savings to highlight the demand savings potential based on the current spending levels of DSM programs. However, the DSM supply curves presented in this section are constructed using the unconstrained achievable potential, which allows for the prioritization of cost-effective measures ahead of less cost-effective measures, and to investigate the maximum demand savings potential that can be achieved.

The program costs used to develop the DSM supply curves are composed of both incentive and non-incentive costs. Incentive costs are the estimated level of monetary incentive required to influence customers to adopt a DSM measure. Non-incentive costs are administrative costs for program delivery activities, including items such as marketing and labour for program staff.

To allow the comparison of different technologies with varying capital costs and measure lifespans, ICF levelized (annualized) the program costs for all DSM measures. The costs were annualized over the measure life using a discount rate equivalent to each of the Gas Utilities' weighted average cost of capital (WACC).

The DSM supply curves prioritize the measures based on their cost-effectiveness, with the most cost-effective measures being implemented first. The measure cost-effectiveness is based on the cost per unit peak hour demand savings. Each of the DSM supply curves includes measures from all of the sectors being considered (residential, commercial, and industrial). For the

[111] Not all DSM measures will impact peak hour or peak day demand in the same way. Most DSM measures are expected to reduce peak hour and peak day demand, although the relative magnitude of the impact will differ by some measure. Adaptive thermostats are expected to reduce peak day demand but increase peak hour demand. Other DSM measures may have no impact on peak hour or peak day demand.

residential and commercial sectors, each measure is split into two: the business as usual (BAU) scenario, which reflects the peak hour savings that can be achieved based on modest incentives; and the aggressive scenario, which demonstrates the incremental peak hour savings and costs based on high incentive levels. Costs and peak hour savings were aggregated for each of the industrial sector measures since these measures were generally found to be much more cost-effective and there was limited value in splitting out the BAU and aggressive scenarios.

2.2 Broad-Based DSM Supply Curve Analysis Results

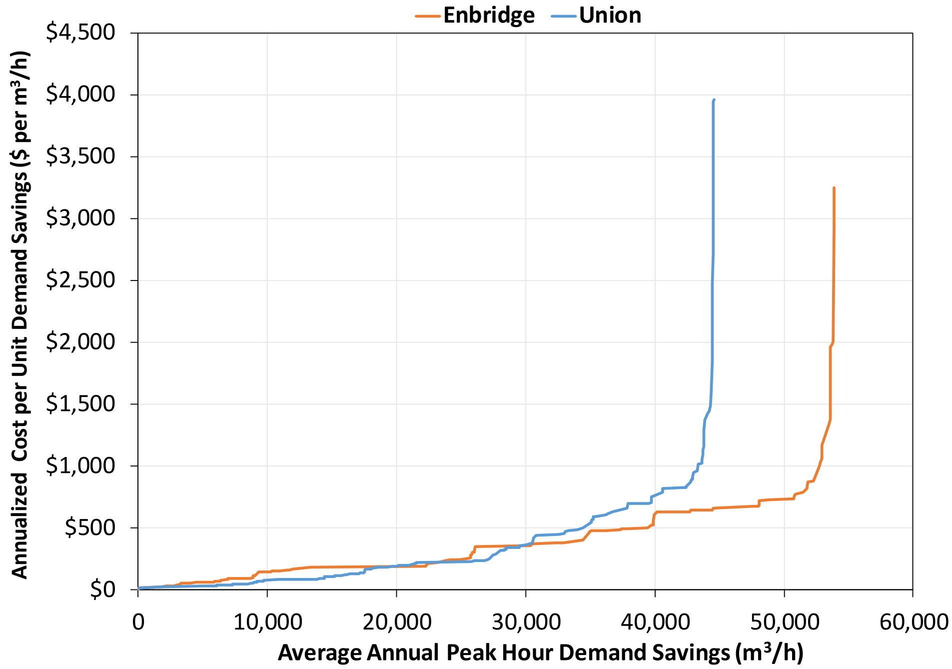
This section presents the results of the DSM supply curve analysis for broad-based DSM. Results are first presented for both Gas Utilities across all customer sectors, followed by the sector-specific results for the residential, commercial, and industrial sectors. These DSM supply curves include all measures corresponding to the unconstrained achievable potential scenario.[112] It should be noted that the DSM supply curves were created based on results specific to the unique distribution of sectors, sub-sectors, end-uses, and applicable measures in each service territory. As such, the DSM supply curves are not universally applicable. Among other factors, changes in customer mix will impact the cost per unit demand savings.

2.2.1 All Sector Results

Broad-based DSM supply curves are presented for each Gas Utility in Exhibit 94. In this exhibit, the DSM supply curve presents the marginal DSM program cost (i.e., \$ per m^3/h) required for each incremental unit of peak hour demand saved. The supply curve was created by arranging the DSM options across all sectors (residential, commercial, and industrial) along a continuum of increasing costs and indicating the amount of peak hour savings each option would generate.

[112] The unconstrained achievable potential scenario is referred to in this section as the "achievable potential".

Exhibit 94: Broad-Based DSM Supply Curves – Annualized Program Costs



For Union Gas, approximately 44,000 m^3/h of peak hour demand savings can be achieved on an annual basis. The marginal costs range from $5 per m^3/h for the most cost-effective measure to almost $4,000 per m^3/h for the least cost-effective measure, with 80% of savings being achievable for a marginal cost of less than $500 per m^3/h. The total annual achievable peak hour demand savings are equivalent to 1.24% of the reference case peak hour demand of 3.54 million m^3/h. By comparison, the average annual peak hour demand growth in the reference case for Union Gas is approximately 23,700 m^3/h (or 0.67%). This suggests that, on a macro-level, there is enough DSM potential to offset the overall growth in peak day and peak hour demand across Union Gas' entire service territory. However, this macro-level analysis doesn't account for the fact that many parts of the pipeline system will experience peak hour demand growth rates much higher than average and higher than the 1.24% demand savings potential.

For Enbridge, about 52,500 m^3/h of peak hour demand savings can be achieved annually. The marginal costs range from $4 per m^3/h for the most cost-effective measure to about $3,250 per m^3/h for the least cost-effective measure, with 76% of these savings being achievable for a marginal cost of less than $500 per m^3/h. The total annual achievable peak hour demand savings are equivalent to 1.05% of the reference case peak hour demand of 5.01 million m^3/h. By comparison, the average annual peak hour demand growth in the reference case for Enbridge is approximately 52,000 m^3/h (or 1.04%). This suggests that, on a macro-level, there is just enough DSM potential to offset the overall growth in peak day and peak hour demand across Enbridge's entire service territory. Again, it should be noted that this macro-level analysis fails to account for regional differences in peak hour demand growth, and many parts of the network will likely be growing at rates beyond what can be offset by DSM.

The most cost-effective measures on the DSM supply curves include industrial control and optimization measures, suggesting these measures should be implemented first if the goal is to reduce peak hour demand. Conversely, residential and commercial measures make up a large portion of the more expensive and least cost-effective measures (the right side of the curves above) and would be a lower priority for a DSM program prioritizing peak hour demand savings. For both Gas Utilities, a substantial amount of peak hour savings is achievable at low cost.

While Exhibit 94 presents the marginal cost for each additional unit of peak hour demand saved, Exhibit 95 presents the weighted average cost per unit of peak hour demand saved for all of the DSM measures implemented up to the corresponding point on the horizontal axis. For example, Exhibit 95 shows that, in order for Union Gas to achieve annual peak demand savings of 10,000 m^3/h, there would be an annualized cost of approximately \$35 per m^3/h of peak demand saved (i.e., an annualized cost of \$350,000). Exhibit 95 shows that the total achievable potential savings could be realized for a weighted average annualized cost of \$322 per m^3/h for Union Gas and \$374 per m^3/h for Enbridge.

Exhibit 95: Broad-Based DSM Supply Curves – Weighted Average Annualized Program Costs

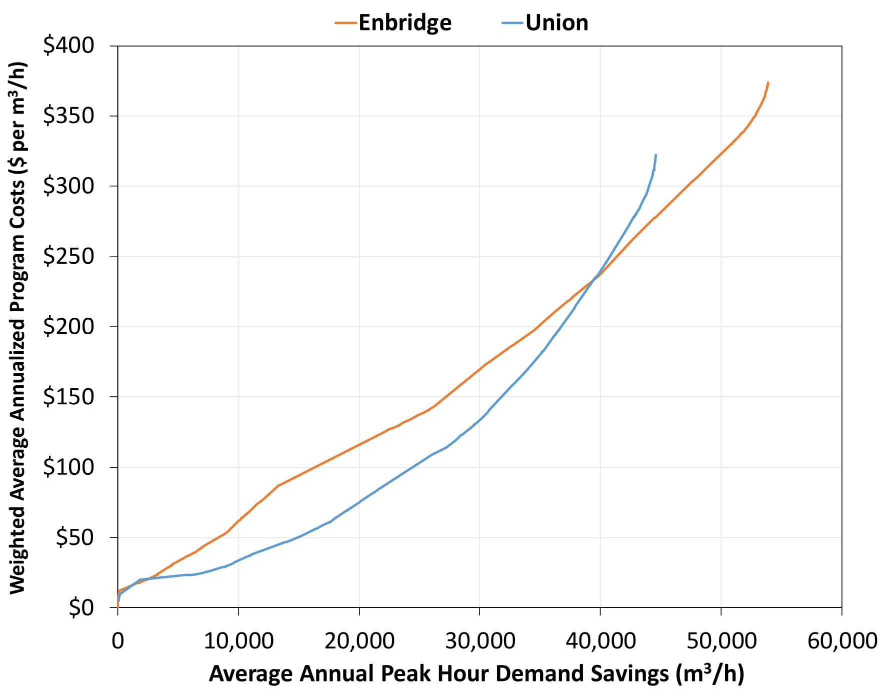


Exhibit 96 and Exhibit 97 re-illustrate the DSM supply curves from Exhibit 95 while also detailing the distribution of savings by sector at various points along the supply curve. These exhibits demonstrate that the most cost-effective DSM measures are in the industrial sector. For example, Exhibit 97 shows that the most cost-effective path for Union Gas to achieve annual peak hour demand savings of 10,000 m^3/h would involve obtaining 92% of the savings from industrial DSM measures. Examples of some of the most cost-effective industrial measures include reducing boiler steam pressure, burning digester gas in boilers, regenerative thermal oxidizers, and ventilation optimization (ranging from an estimated annualized cost of \$4 to \$23 per m^3/h). While industrial measures account for the majority of the lower end of the supply curve, these measures are complemented by some commercial and residential behavioral, optimization, and control type measures. Commercial measures such as ventilation fan VFDs and ozone laundry treatment are also very cost-effective (estimated annualized costs of \$9 to \$11 per m^3/h and \$18 to \$26 per m^3/h, respectively).

Measures that were found to be the least cost-effective are mostly commercial and residential sector measures. This includes commercial measures such as wall insulation, ENERGY STAR clothes washers, and advanced BAS/controllers.

Exhibit 96: Sector Contributions to Enbridge Broad-Based DSM Supply Curve

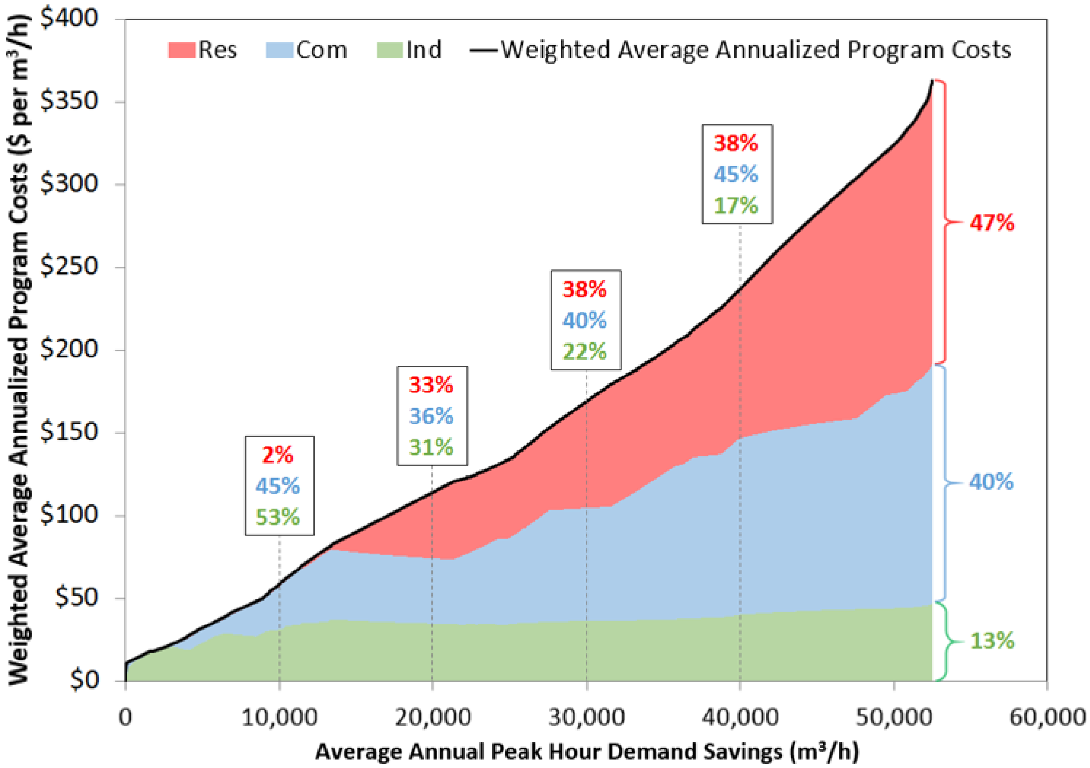
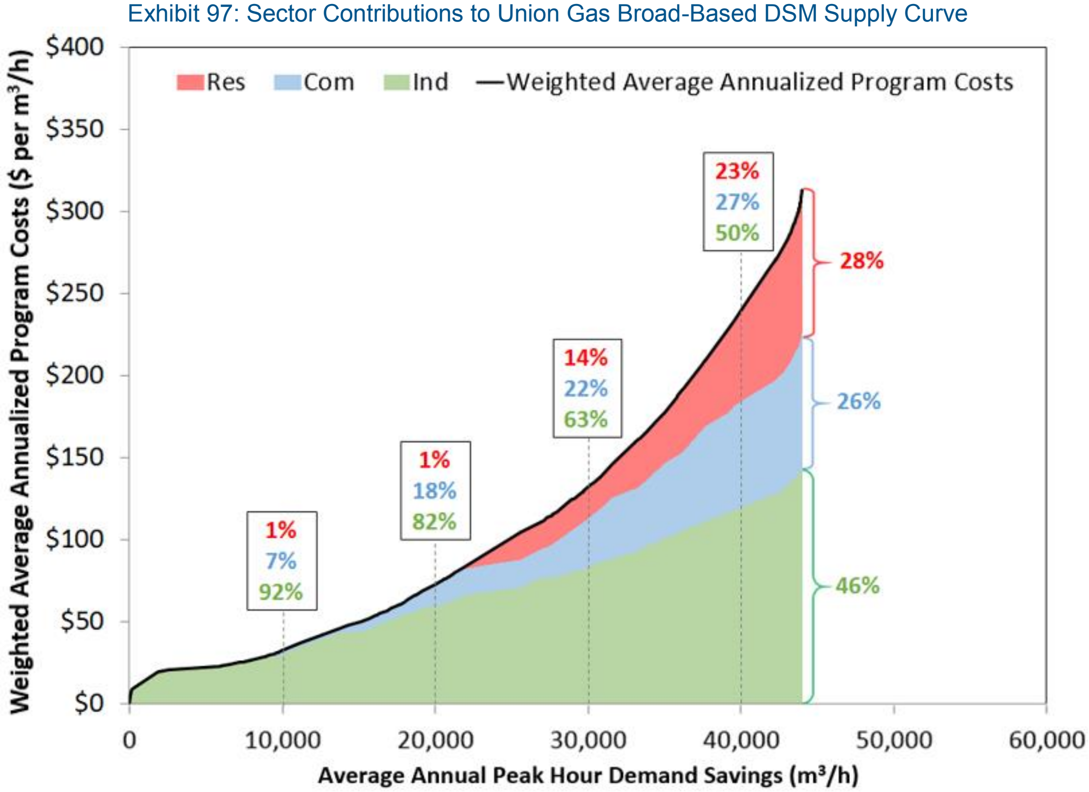


Exhibit 97: Sector Contributions to Union Gas Broad-Based DSM Supply Curve

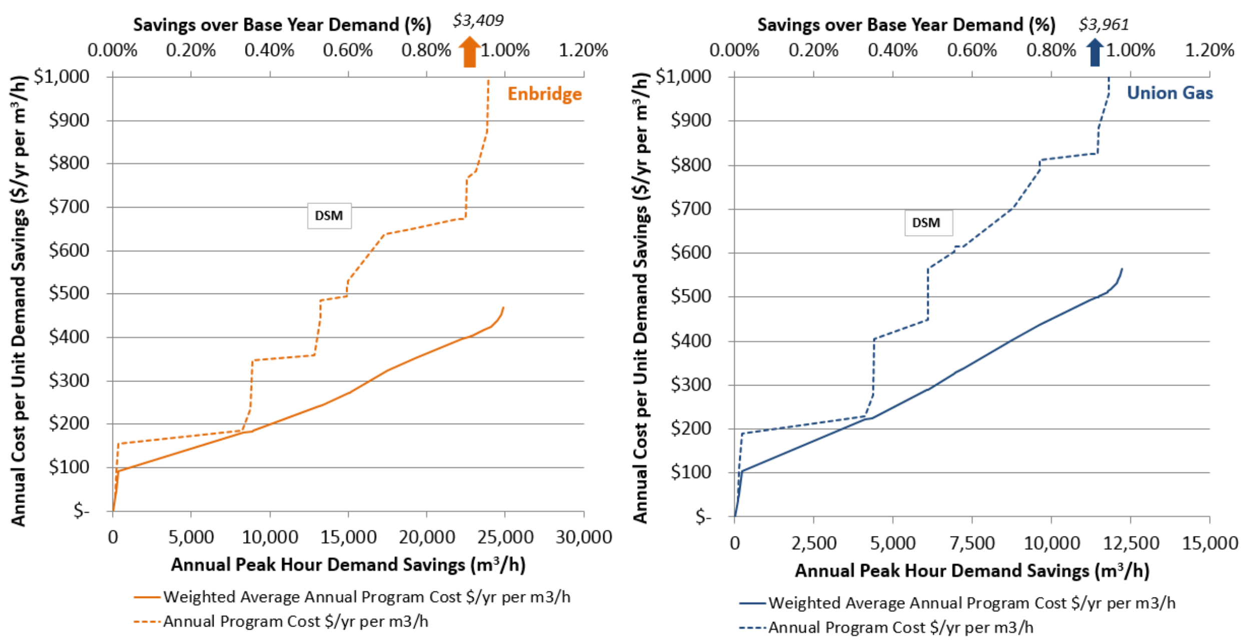


2.2.2 Residential Sector

The DSM supply curves for the Gas Utilities' residential sectors are presented in Exhibit 98. These broad-based DSM supply curves show the cost of implementing DSM measures against their peak hour demand savings. These charts show both the marginal annual program costs and the annual weighted average cost per unit peak hour demand savings on the vertical axis (i.e., annual program costs are plotted on the dashed line, while the weighted average annual program costs are shown on the solid line). The primary horizontal axis presents the average annual peak hour demand savings (m^3/h), while the secondary horizontal axis located at the top of the graph illustrates what these peak hour demand savings represent as a savings percentage over the base year peak hourly demand for the residential sector.

Enbridge's residential annual peak hour demand savings of about 24,850 m^3/h represents an estimated 0.98% savings over the base year peak hour demand. Union Gas' residential DSM cumulative annual peak demand savings of approximately 12,200 m^3/h also represents an estimated 0.98% savings over the base year peak hour demand. Examples of some of the most cost-effective residential measures include pipe wrap and faucet aerators (ranging from an estimated annual cost of $33 to $40 per m^3/h), while the least cost-effective measures include higher efficiency furnaces, ENERGY STAR for New Homes, and fireplace intermittent ignition controls.

Exhibit 98: Broad-Based DSM Supply Curves for Enbridge & Union Gas – Residential Sector

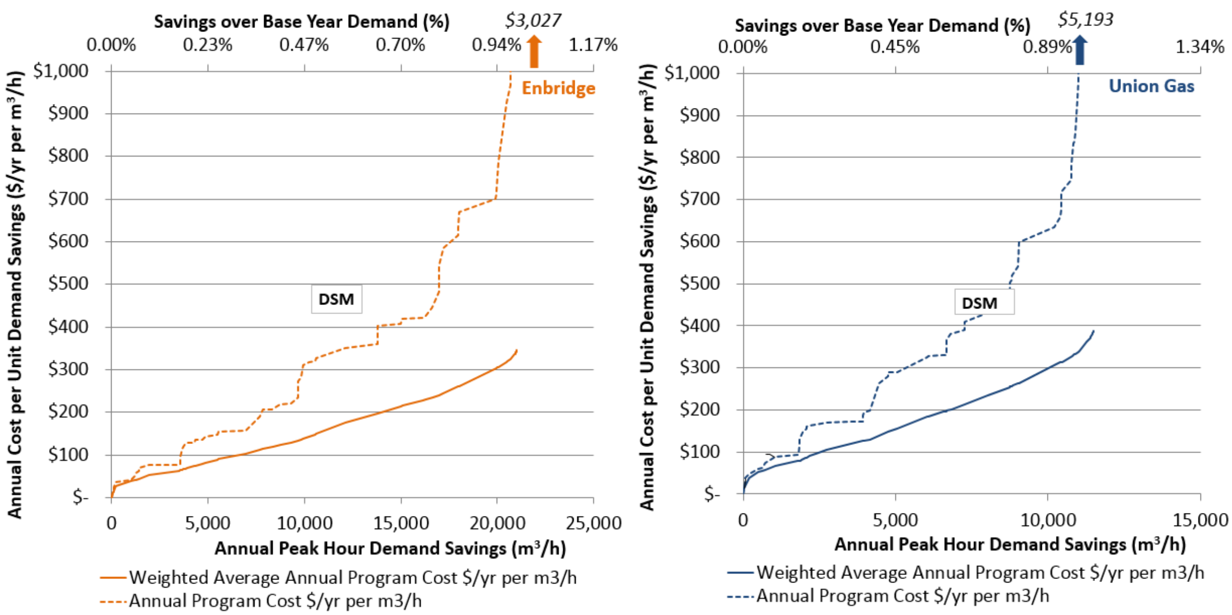


2.2.3 Commercial Sector

The DSM supply curves for the Gas Utilities' commercial sectors are presented in Exhibit 99. These broad-based DSM supply curves show the cost of implementing DSM measures against their peak hour demand savings. Similar to the exhibits for the residential sector, these charts show both the annual program costs and the annual weighted average cost per unit demand impact on the vertical axis (annual program costs are plotted on the dashed line, while the weighted average annual program costs are shown on the solid line). The primary horizontal axis presents the average annual peak hour demand savings (m^3/h), while the secondary horizontal axis located at the top of the graph illustrates what these savings represent as a savings percentage over the base year peak hourly demand for the commercial sector.

Enbridge's commercial annual peak hour demand savings of about 21,000 m^3/h represents an estimated 0.98% savings over the base year peak hour demand. Union Gas' commercial DSM cumulative annual peak hour demand impact of approximately 11,500 m^3/h represents an estimated 1.03% savings over the base year peak hour demand. Examples of some of the most cost-effective commercial measures include ventilation fan VFDs, ozone laundry treatment, and refrigeration waste heat recovery (ranging from an estimated annual cost of $12 to $39 per m^3/h), while the least cost-effective measures include advanced BAS/controllers and condensing storage water heaters.

Exhibit 99: Broad-Based DSM Supply Curves for Enbridge & Union Gas – Commercial Sector



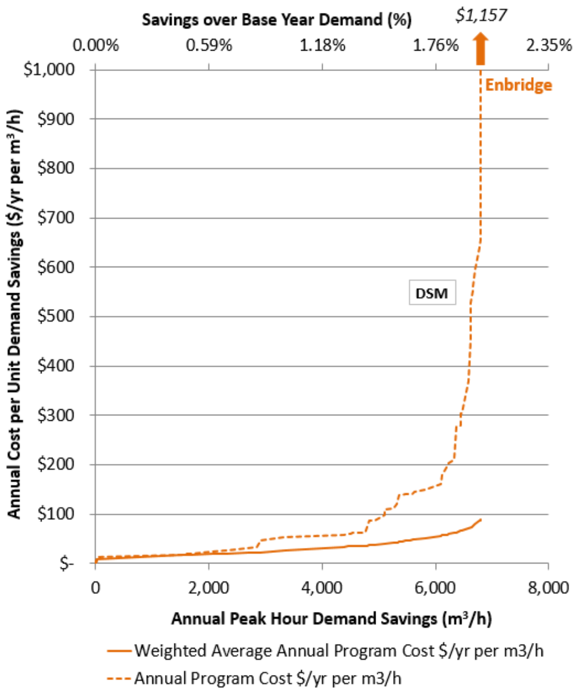
2.2.4 Industrial Sector

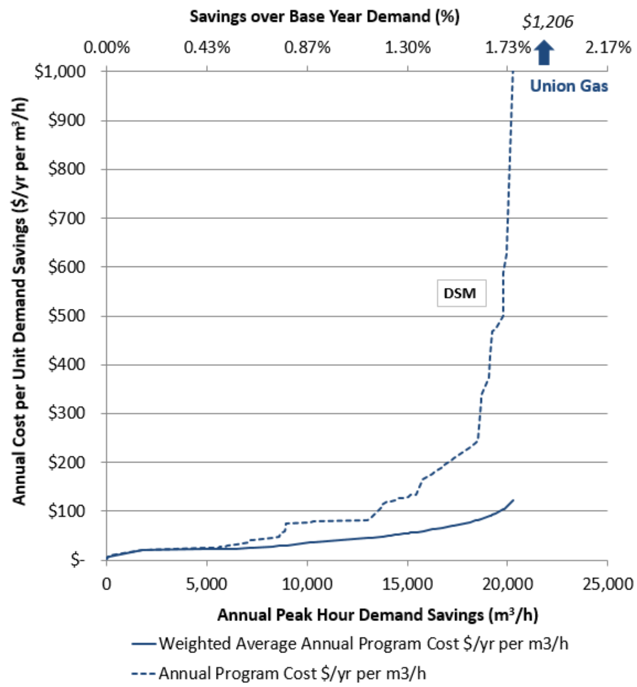
The DSM supply curves for the Gas Utilities' industrial sector are presented in Exhibit 100. These broad-based DSM supply curves show the cost of implementing DSM measures against their demand savings. Similar to the exhibits for the other two sectors, these charts show both the annual program costs and the annual weighted average cost per unit peak hour demand impact on the vertical axis (annual program costs are plotted on the dashed line, while the weighted average annual program costs are shown on the solid line). The primary horizontal axis presents the average annual peak hour demand impact (m^3/h), while the secondary horizontal axis at the top of the graph illustrates what these savings represent as a savings percentage over the base year peak hourly demand for the industrial sector.

Enbridge's industrial annual peak hour demand savings of about 6,800 m^3/h represents an estimated 2.00% savings over the base year peak hour demand. Union Gas' industrial DSM cumulative annual peak demand impact of approximately 20,300 m^3/h represents an estimated

1.76% savings over the base year peak hour demand. Examples of some of the most cost-effective industrial measures include reducing boiler steam pressure and regenerative thermal oxidizers (ranging from an estimated annual cost of $4 to $13 per m^3/h), while the least cost-effective measures include mining process improvements and refining process improvements.

Exhibit 100: Broad-Based DSM Supply Curves for Enbridge & Union Gas – Industrial Sector





2.3 Broad-Based DSM Supply Curves Summary

The DSM supply curves for the Gas Utilities are relatively flat up to the last few increments of technically achievable DSM peak hour demand savings. The industrial sector appears to be the area where most of the low-cost DSM options and savings are to be found for both Gas Utilities. Creating weighted average annual program cost curves shows that combining a number of DSM options generates substantial savings at costs comparable to some facility investments. These weighted average costs are used later in the analysis to examine the implications for facilities planning.

3. Intersection 2: New Subdivision and Community Facilities Planning

This section covers the second area of intersection for this study:

- **Intersection 2:** Geo-Targeted DSM Impacts on Facilities Planning for New Subdivisions or Community Projects

Serving new communities typically requires a significant investment in new pipeline capacity to deliver gas to the community, as well as reinforcements on existing parts of the system to meet the growth in overall requirements. Natural gas utilities routinely engage with builders as they develop new subdivisions to promote the use of gas and encourage the installation of efficient gas-fired appliances, furnaces, and hot water heaters. Builders tend to favor low up-front costs; thus, a program to incentivize builders to install more efficient equipment would tend to benefit the utility system as a whole. Similar issues arise when a utility expands to an existing community, where gas equipment often replaces oil or propane equipment.

Given the nature of a new subdivision or community expansion to provide the initial gas service to the community, DSM programs would not be useful in deferring the facility investment. Rather, in certain circumstances, the overall magnitude of the investment and project might be reduced if the DSM programs alone, or in conjunction with other distributed energy resources, are capable of reducing the expected peak hour demand in the new community.

The Gas Utilities reviewed several planned subdivision and new community expansion projects and provided ICF with sufficient details to construct a region-specific DSM supply curve for a representative new community project (geo-targeted DSM supply curve). These details included the anticipated cost of facilities expansion projects, initial and projected system peak hour demand, and the best available data regarding the breakdown of peak hour demand by different building types.

3.1 Geo-Targeted DSM Supply Curve Analysis Approach

The DSM supply curves developed as part of Intersection 1 are based on broad-based regional averages, including the distribution of different building types, and the best available data on the penetration of different types of energy-efficiency measures across each of the Gas Utilities' service territories. These broad-based DSM supply curves were scaled to a regional level to estimate the peak hour demand savings resulting from the implementation of geo-targeted DSM at the level of an individual facility investment.

However, this approach has some key limitations that increase the uncertainty of the results. For example, the penetration of different types of energy-efficiency measures could be significantly higher or lower than the penetration of the broader region.

Another item that warranted special attention was the program costs associated with implementing DSM at the geo-targeted level. Simply scaling the program costs from the broad-based analysis to estimate the geo-targeted program costs ignores the fact that there are efficiencies of scale associated with implementing DSM programs across a large service territory, and that these will not translate to geo-targeted programs. For an equivalent program size (i.e., $/yr.), geo-targeted programs will be more expensive per unit of peak hour demand impact than broad-based DSM programs because of factors such as the need for metering and on-going monitoring of peak hour demand impacts. Essentially, although incentive costs are independent of the program size, administrative costs would be much higher for geo-targeted programs.

Based on the review of a 2014 ACEEE study[113] and ICF's experience with implementing DSM programs across North America, ICF estimated that the cost of implementing geo-targeted DSM

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[113] Molina, Maggie, ACEEE, The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs, Report #U1402, March 2014

programs would be in the range of 1.5 to 2 times more expensive than implementing broad-based DSM programs, on a per unit peak hour demand savings basis. As such, both lower and upper range estimates are provided for the cost of implementing geo-targeted DSM programs.

The following approach was taken to compare facility investment projects to DSM:

- The full annual investments (program costs, including both incentives and admin) for DSM were modeled on an extended timeframe.
- It was assumed that DSM would start being implemented 3 years ahead of a facility investment project.
- The present value of the DSM program costs were compared against the present value of the facility investment project costs.

3.2 Geo-Targeted DSM Supply Curve Analysis Results

In order to evaluate the potential for geo-targeted DSM to reduce facility investments needed to serve new demand by downsizing the amount of incremental capacity required and allowing a smaller sized project to be developed, ICF used information provided by the Gas Utilities to create a scenario in which the demand from a new community is expected to be near the maximum capacity of a nominal pipe size (NPS) planned to be installed in the community. This hypothetical scenario was developed for a community in Union Gas' South region having a peak hour demand breakdown of 37% residential, 37% commercial, and 26% industrial. For this scenario, it was assumed that an NPS 2 steel pipe can be installed for $5,275,000 and provide a maximum capacity equal to the new community's initial peak hour demand of 675 m^3/h. As an alternative option, it was assumed that an NPS 4 steel pipe can be installed for $6,000,000 and provide a maximum capacity of 4,160 m^3/h (i.e., for an incremental cost of $725,000, the NPS 4 steel pipe could easily serve the community's peak hour demand for many years).

For this analysis, ICF developed a geo-targeted DSM supply curve using the following methodology:

- The broad-based DSM supply curve for Union Gas' South region was scaled to represent a community with a peak demand of 675 m^3/h. This scaling process was completed separately for each sector to account for any differences in customer mix at the community level compared to the broader region.
- The costs of DSM were adjusted to reflect the increased costs of a geo-targeted DSM program per unit of peak hour demand saving (as discussed in Section 3.1). A lower estimate for geo-targeted DSM costs was obtained by multiplying the broad-based DSM cost per unit of peak demand savings by a factor of 1.5, while an upper estimate for geo-targeted DSM costs used a factor of 2.

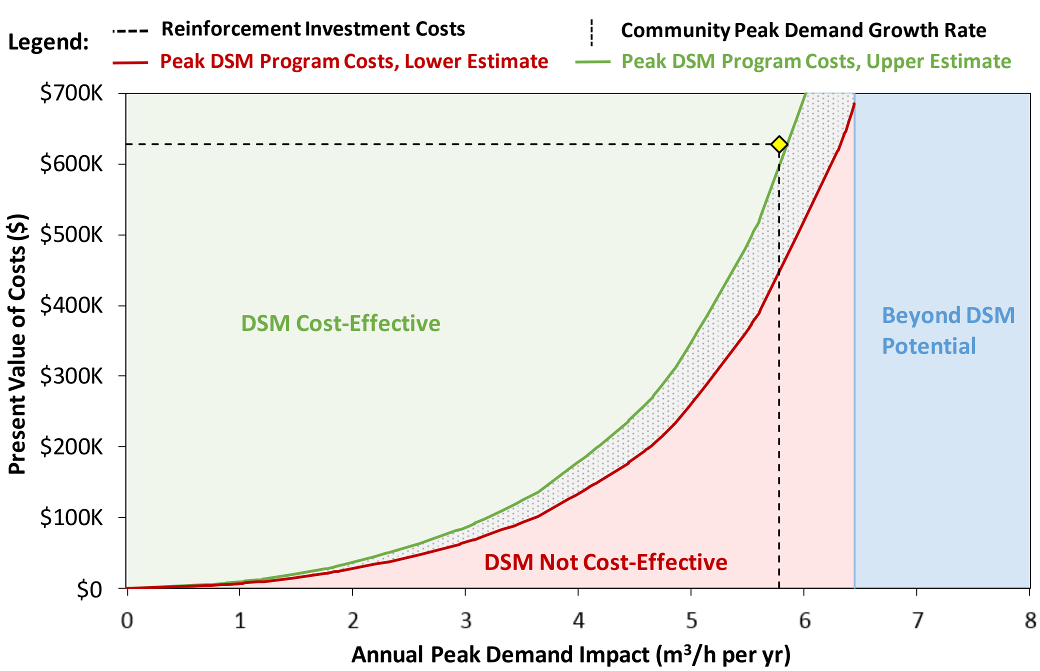
This study included an assessment of the annualized costs of implementing natural gas DSM programs in a large number of U.S. jurisdictions and provided a sense of how much these costs vary.

The resulting geo-targeted DSM supply curve is shown in Exhibit 101, where it appears as a grey band marked by a red lower bound and a green upper bound. This grey band represents the likely range of geo-targeted DSM costs for a given level of annual peak demand savings.[114]

To compare this with the cost of installing NPS 4 pipe (or any facility investment), Exhibit 101 also includes a dashed vertical line that represents annual peak demand growth rate for the hypothetical community expansion project (5.8 m^3/h, or about 0.8% per year). The yellow diamond represents the cost of a proposed facility investment necessary to meet this growth rate for the community expansion. In the figure below, the present value (PV) of the facility investment cost is about $635,000 (the dashed horizontal line), with which is above the grey area defining the DSM supply curve at the same growth rate. Hence, DSM is likely to be more cost effective than the facility investment. If the costs of installing NPS 4 pipe were significantly lower to meet the growth rate of 5.8 m^3/h, then the facility investment would be more cost effective. Any facility investment falling in the green area of the graph would be more expensive than a DSM option. Facility investments falling in the red area would be less expensive and therefore preferable to a DSM option.

This analysis suggests that geo-targeted DSM can cost-effectively offset the growth of the community (i.e., for the given growth rate of the community, the PV of geo-targeted DSM costs is less than the PV of installing the larger NPS 4 pipe).

Exhibit 101: Comparison of Facility Investment for a New Community with Geo-Targeted DSM Investment at Different Peak Hour Demand Growth Rates



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114 It should be noted that while DSM costs are presented as a range in the following exhibit and **Error! Reference source not found.Error! Reference source not found.**several exhibits that follow. The costs shown are intended to represent a best estimate of geo-targeted costs and it is possible for the costs of an actual geo-targeted DSM program to fall outside of this range.

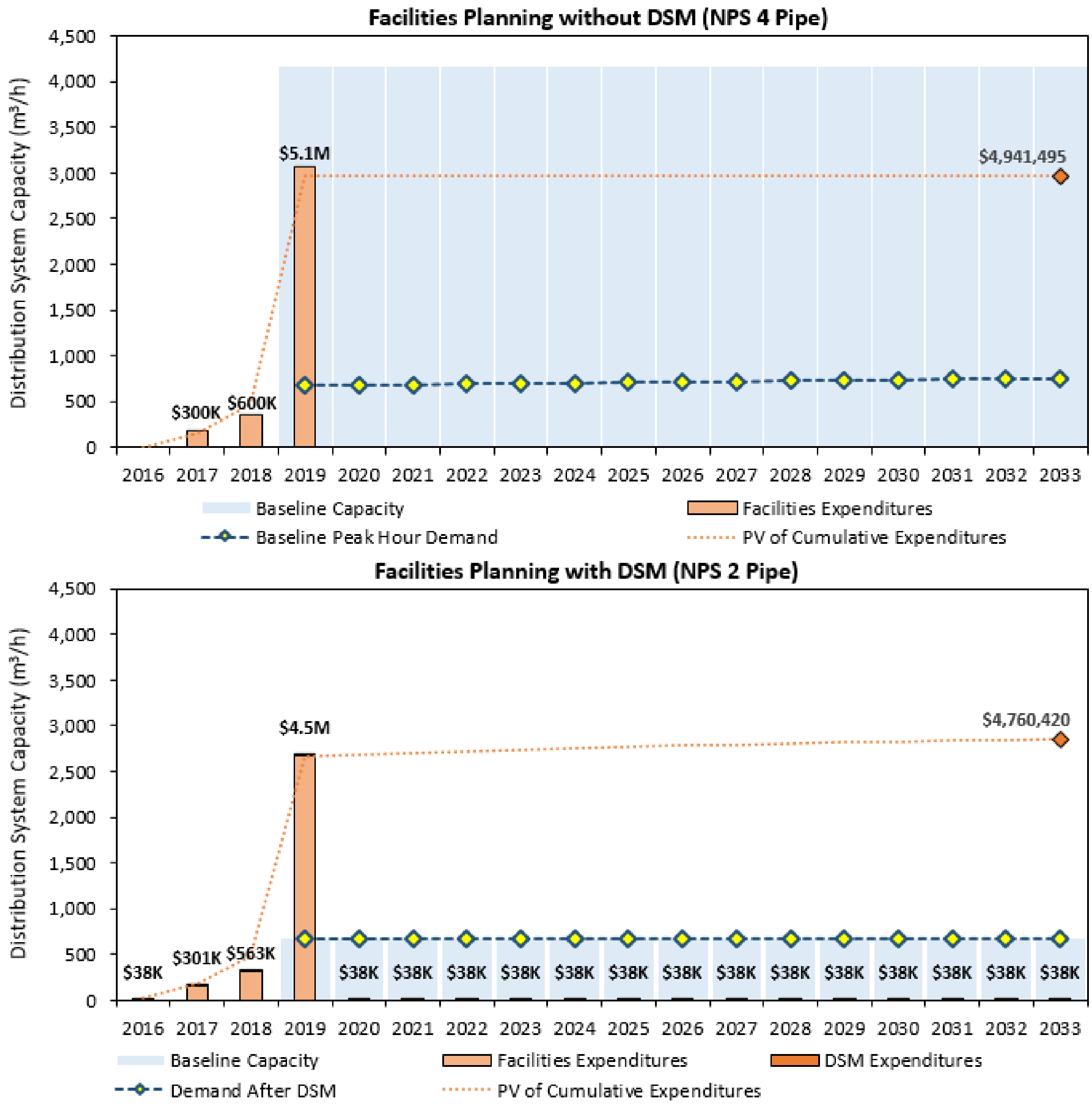
At growth rates higher than 5.8 m^3/h the cost advantage of DSM over facilities expansion shrinks. At a growth rate of approximately 6.4 m^3/h, the cost advantage disappears. The blue area to the right represents an area, on this graph, where geo-targeted DSM by itself is less likely to be useful in meeting the expansion of demand. It is more likely that facilities expansion or some combination of facilities expansion and geo-targeted DSM would meet demand growth.

The graph in exhibit 102 suggests, but does not show, the time dimension of implementing DSM to delay facility investments. It is possible that a DSM program implemented one or two years in advance of constructing new facilities can slow demand growth and defer the facilities.

Exhibit 102 compares the estimated cash flows necessary for the installation of an NPS 4 pipe against the estimated cash flows for the installation of an NPS 2 pipe in conjunction with the implementation of a geo-targeted DSM program. In this exhibit, the light orange columns indicate facility investment expenditures, while the dark orange columns (barely visible in this instance) show the DSM expenditures. To facilitate the comparison between the two scenarios, each chart in the exhibit also includes a dotted orange line that represents the cumulative PV of costs. The exhibit also includes light blue columns to show the pipeline capacity available to meet peak demand, as well as a dashed line with yellow diamonds marking the peak demand on an annual basis.

This analysis shows that the DSM scenario with the NPS 2 pipe is less costly from a PV perspective (~$4.76M vs ~$4.94M). The comparison of the cases illustrates how the NPS 4 pipe leads to excess capacity relative to peak hour demand, while with the NPS 2 pipe, the capacity of the pipeline is perfectly matched to the post DSM peak hour demand (i.e. there is no slack in the system). It should be noted that the DSM scenario assumes an optimal implementation of DSM, both in the sense that measures are invariably implemented according to the supply curve (from most cost-effective to least cost-effective), and in the sense that DSM implementation stops as soon as sufficient peak demand growth has been offset (DSM spending is minimized). In other words, the analysis assumes that there is no room for error when it comes to implementing DSM, while only resulting in PV savings of approximately $180,000 over a 17-year time span.

Exhibit 102: Comparison of Expenditures with and without DSM for a Hypothetical New Community Expansion



3.3 Assessment of Potential for DSM Programs to Impact New Community Infrastructure Requirements

The hypothetical example discussed in Section 3.2 suggests that, in the context of a new subdivision or community, it may be technically and economically feasible to install a smaller and less expensive pipe in certain instances if this is coupled with the implementation of a geo-targeted DSM program. However, there are several areas of uncertainty that need to be considered when weighing the benefits of a geo-targeted DSM program:

- The actual peak hour demand from the newly serviced community may be larger than expected

- The penetration of key energy-efficient measures may be higher than average, limiting DSM's potential to reduce peak hour demand
- The growth rate of the newly serviced community may be unknown or may be too large to be offset by a geo-targeted DSM program
- Does not plan for unexpected growth for large commercial or industrial customers who may want to locate in the community as it grows.

4. Intersection 3: Geo-Targeted DSM and Reinforcement Facilities Planning

This section covers the third area of intersection for this study:

- **Intersection 3:** Geo-Targeted DSM and Facilities Planning for System Reinforcement (Active Deferral)

This type of geo-targeted DSM program targets peak hour and peak day demand reductions in specific areas where facility investments are planned for a distribution system, with the intent to reduce the need for the facility investments. The use of geo-targeted DSM programs to reduce specific facility investments requires three key steps:

- Identifying facility investments that could be reduced by a reduction in peak hour demand[115]
- Designing and implementing cost-effective DSM programs capable of reducing peak hour demand sufficient enough to reduce the facility investment within the available timeframe
- Verifying the effectiveness of the DSM programs on a timeline sufficient to ensure that the facility investment can be reduced without impacting the Gas Utilities' ability to reliably serve natural gas system demand

4.1 Review of Reinforcement Facilities Planning Process

Based on criteria provided by ICF, a variety of planned distribution facility investments were selected by the Gas Utilities for deeper analysis. This subset of distribution facility investments was strategically selected to review a mix of different types of projects (e.g., urban vs. rural, different types of soil/bedrock, low vs. high demand growth). For each of these planned facility investments, the Gas Utilities provided ICF with key details such as the anticipated costs and in-service date of the project, the total peak hourly demand on the existing pipeline system, and the annual growth in peak hour demand experienced by the pipeline system. Since the mix of customers on the localized network may differ substantially from the mix of customers in the broader region, the Gas Utilities also provided ICF with estimates of the customer mix specific to each planned distribution facility investment. ICF leveraged this information to produce geo-targeted DSM supply curves for several planned facility investments by scaling the applicable broad-based DSM supply curve. The geo-targeted DSM supply curves were then used to compare the estimated costs of geo-targeted DSM programs against the costs of the planned

[115] Many facility investments are driven by pipeline integrity requirements, class location, and/or municipal replacement requirements, and would not have the flexibility to be delayed or avoided.

facility investments. Furthermore, the following approach was taken to compare the facility investments to DSM:

- The full annual investments (program costs, including both incentives and administration) for DSM were modeled on an extended timeframe
- It was assumed that three years of DSM implementation could be achieved prior to the in-service date of the planned facility investment
- The present value of the geo-targeted DSM program costs was compared against the present value of the facility investment project costs

4.2 Geo-Targeted DSM Supply Curve Analysis Approach

The DSM supply curves developed as part of Intersection 1 are based on broad, regional-based averages, including the distribution of different building types, and the best available data on the penetration of different types of energy-efficiency measures across each Gas Utilities' service territory. These broad-based DSM supply curves were scaled to a regional level to estimate the peak hour demand savings resulting from the implementation of geo-targeted DSM at the level of an individual facility investment. Since the process used for the Intersection 2 analysis is very similar to the approach for the Intersection 3 analysis, it is not repeated here. Readers should review Section 3.1 for more details regarding the geo-targeted supply curve analysis approach for Intersection 3.

4.3 Geo-Targeted DSM Supply Curve Analysis Results

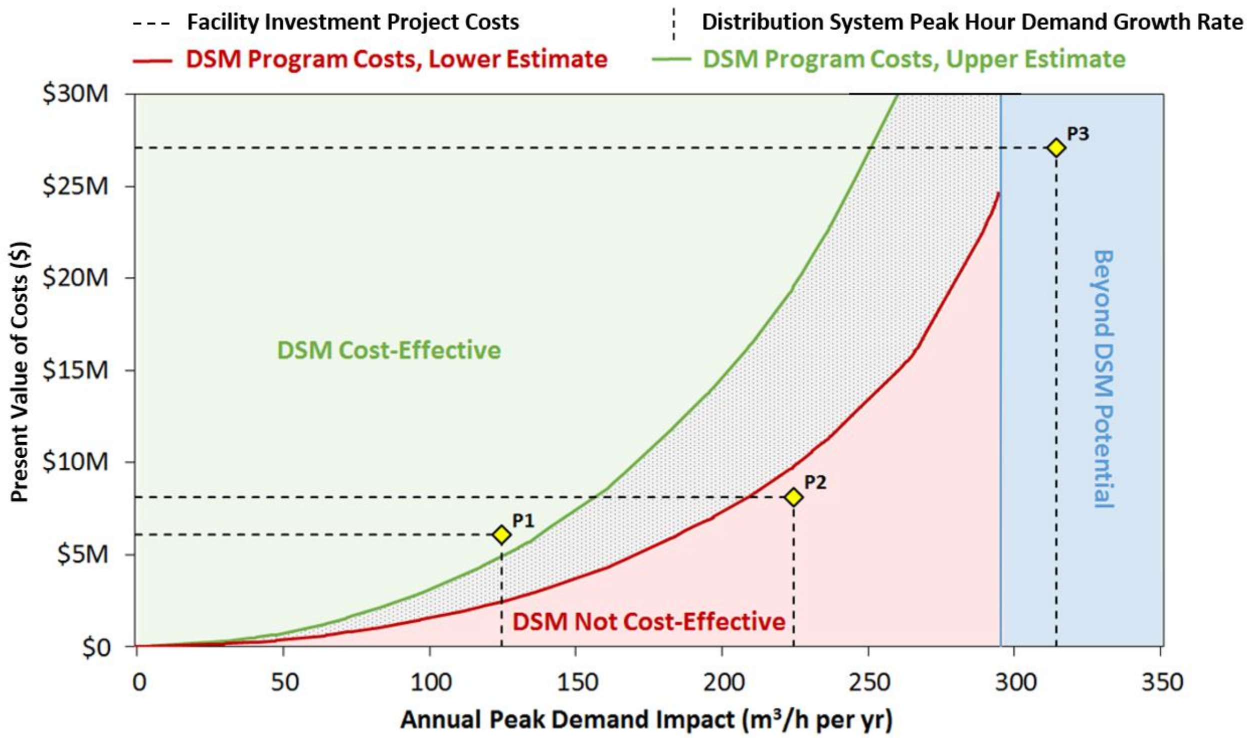
Exhibit 104 recreates the approach shown in exhibit 102 to show that there are three broad outcomes possible when comparing the costs of a geo-targeted DSM program to the costs of a facility investment project:

- **P1:** In this outcome, the geo-targeted DSM program can offset growth in peak hour demand sufficiently to defer the planned facility investment. The PV cost of the geo-targeted DSM program is projected to be less than the PV cost of the planned facility investment at the expected peak hour demand growth rate.
- **P2:** In this outcome, the geo-targeted DSM program can offset growth in peak hour demand to the extent necessary to defer the planned facility investment, but the PV cost of the geo-targeted DSM program is projected to be greater than the PV cost of the planned facility investment
- **P3:** In this outcome, the geo-targeted DSM program is incapable of reducing peak hour demand to the extent necessary to defer the planned facility investment

Each of these potential outcomes is further illustrated below in the following three case studies.[116]

[116] Note that the case studies are not linked to pilot studies in Deep River/Ingleside.

Exhibit 103: Comparing Alternative Facility Investments with Geo-Targeted DSM Investment for a Distribution Company



Case Study 1: Geo-Targeted DSM Costs Less than Planned Facility Investments

Exhibit 104 presents the geo-targeted DSM supply curve for a distribution system located in Enbridge's Central region, where 48% of the peak hour demand is attributed to residential customers, and the remaining 52% to commercial customers. The current peak hour demand from the distribution system is approximately 30,000 m^3/h and is growing at an average rate of 158 m^3/h per year (or 0.5%). Based on information provided by Enbridge, the peak hour demand growth will need to be accommodated by a facility investment project that is anticipated to have a capital cost of approximately $8,200,000 for the installation of 3.2 km of an NPS 12 steel high-pressure pipeline.

For this case study, geo-targeted DSM appears to be a cost-effective. This result is shown in Exhibit 104, where it can be seen that the PV of the planned facility investment project is approximately $6.7M, while it is estimated that a geo-targeted DSM program can provide the necessary annual peak hour demand savings of 158 m^3/h for a PV cost ranging somewhere between $3.7M and $4.9M.[117]

The cash flows for each scenario are displayed in Exhibit 105, where it can be seen that annual expenditures of $379,000 on geo-targeted DSM until 2033 would result in a total PV cost of ~$4.3M while maintaining the peak hour demand below the capacity of the existing distribution pipeline.

[117] This range of geo-targeted DSM program costs corresponds to the points on the green line and the red line along the vertical dotted line corresponding to 158 m^3/h.

Exhibit 104: Comparing Facility Investment with Geo-Targeted DSM in Enbridge's Central Region (Case Study 1)

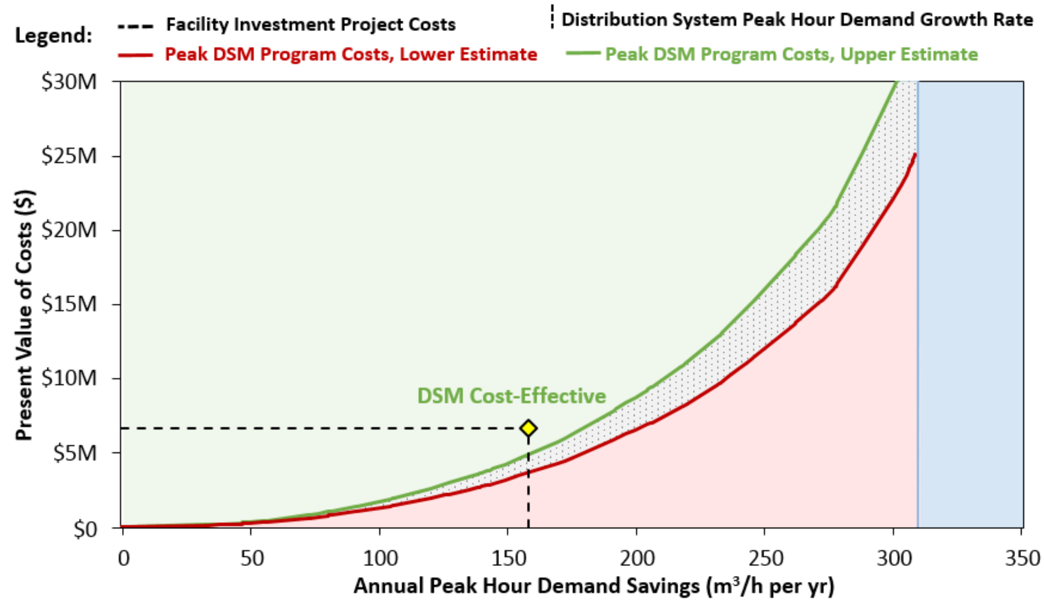
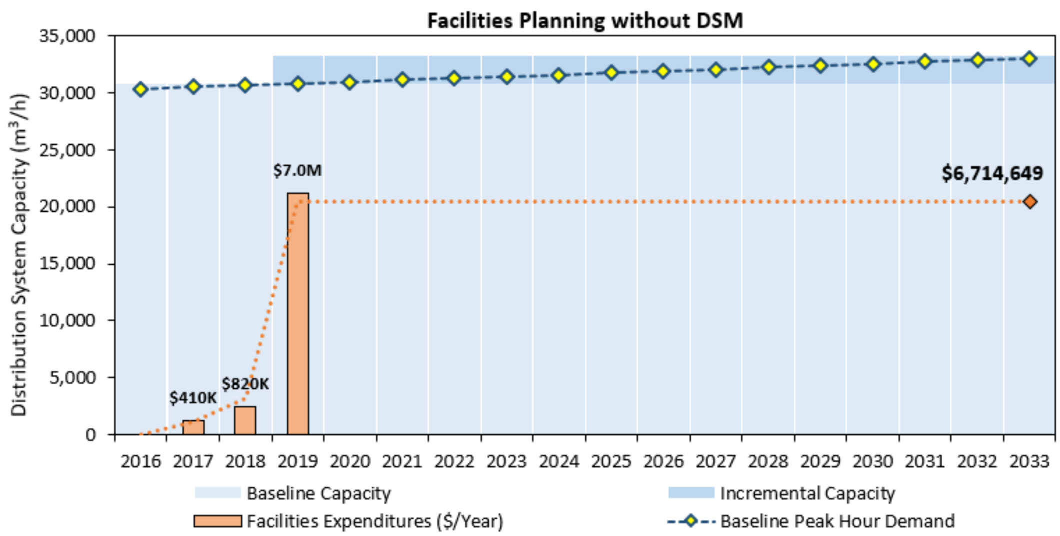
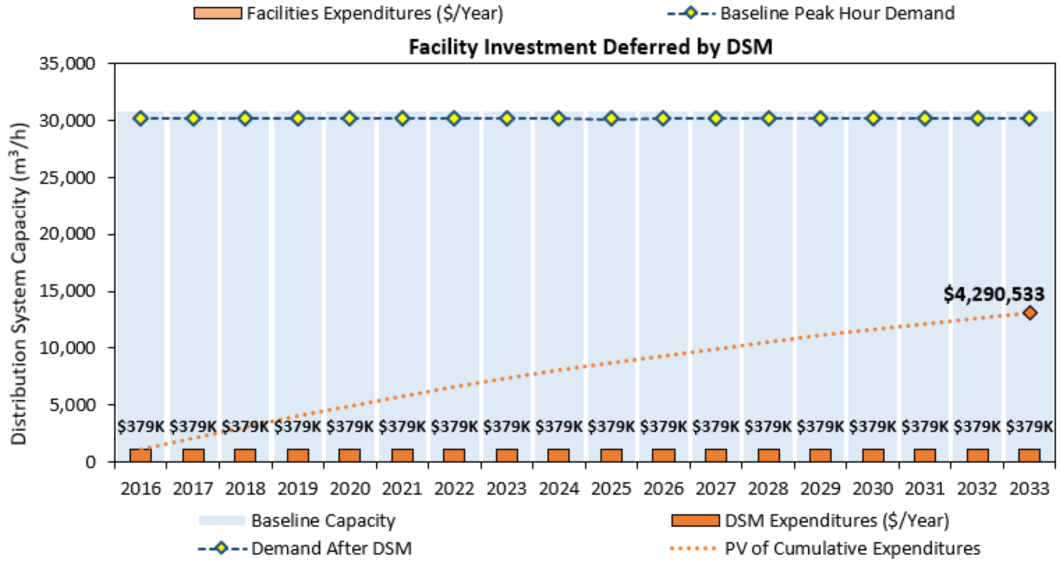


Exhibit 105: Comparison of Facility Planning Cash Flows with and without Geo-Targeted DSM (Case Study 1)





Case Study 2: Geo-Targeted DSM Costs More than Facility Investment Project Costs

Exhibit 106 presents the geo-targeted DSM supply curve for a distribution system located in Union Gas' North region, where 58% of the peak hour demand is attributed to residential customers, while commercial and industrial customers account for 38% and 4% of peak hour demand, respectively. The current peak hour demand from the distribution system is approximately 26,100 m^3/h and is growing at an average rate of 194 m^3/h per year (or 0.7%). Based on information provided by Union Gas, the peak hour demand growth will need to be accommodated by a facility investment project that is anticipated to have a capital cost of approximately $690,000 for the installation of 1.3 km of an NPS 6 steel 6895 kPa pipeline.

This case study provides an example of a situation where a geo-targeted DSM program would not be a cost-effective option for deferring a planned facility investment. Although ICF's analysis suggests that a geo-targeted DSM program would have enough potential to offset this growth, Exhibit 107 shows that such a program is estimated to have a PV cost in the range of $7.2M to $9.6M, while the planned facility investment has a PV cost of only $568,000. This result is also illustrated in Exhibit 107, where it can be seen that annual expenditures of $731,000 on geo-targeted DSM until 2033 would result in a total PV cost of ~$8.4M while maintaining the peak hour demand below the capacity of the existing distribution pipeline.

Exhibit 106: Comparing Facility Investment with Geo-Targeted DSM in Union Gas' North Region (Case Study 2)

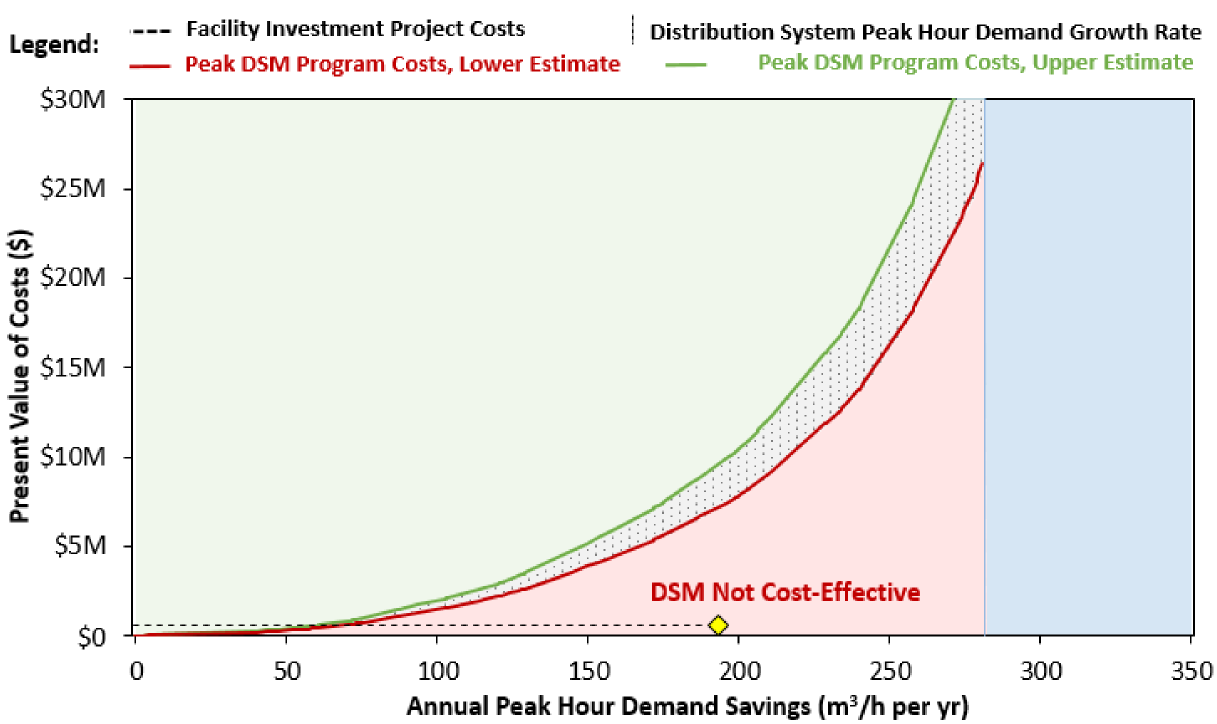
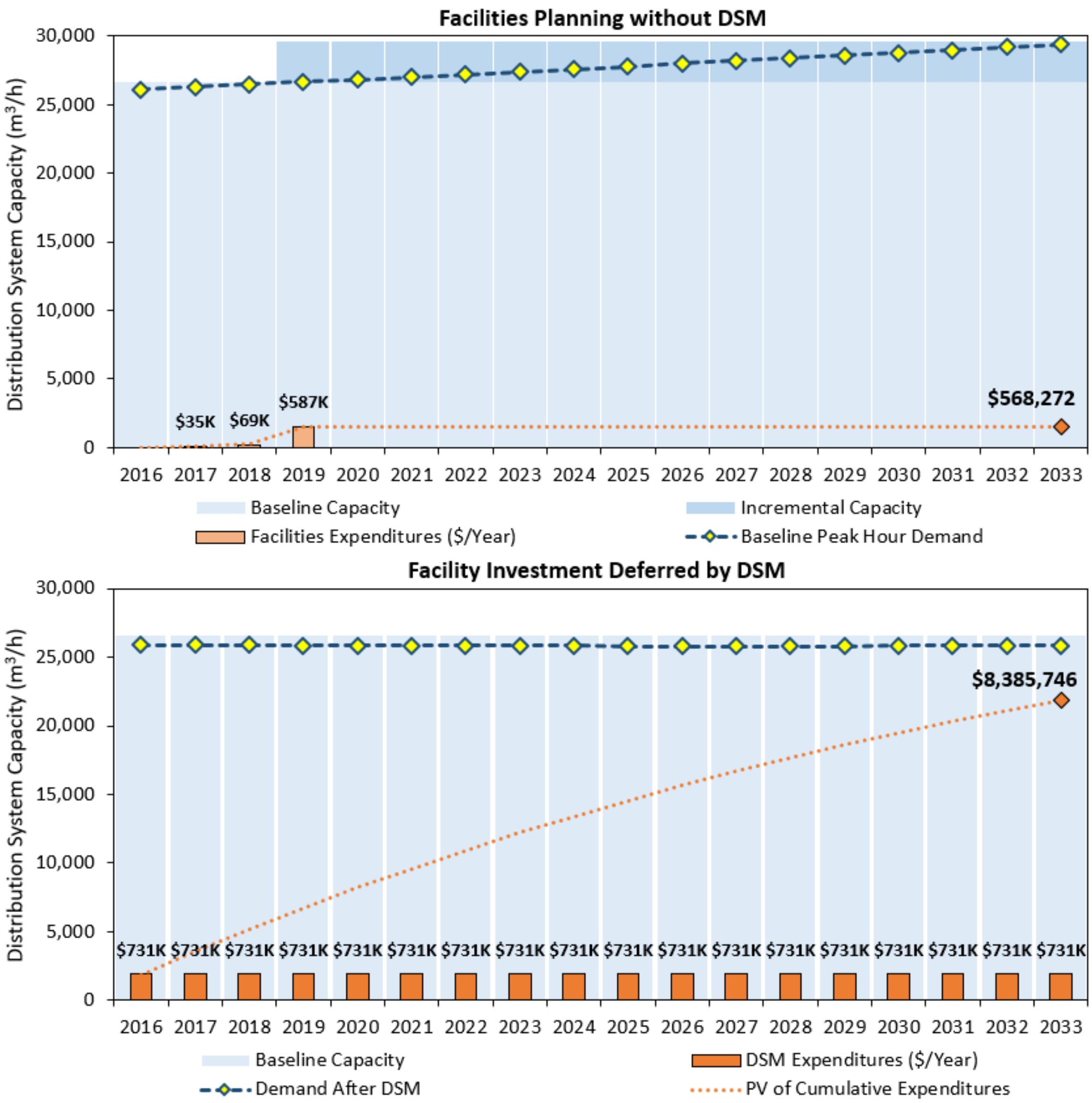


Exhibit 107: Comparison of Facilities Planning Cash Flows with and without Geo-Targeted DSM (Case Study 2)

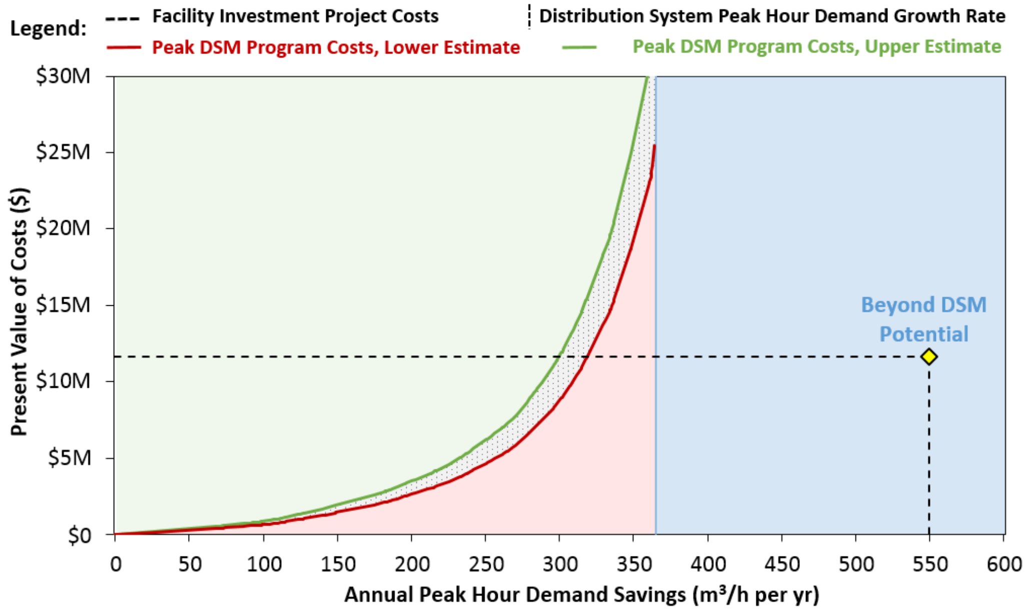


Case Study 3: Geo-Targeted DSM Unable to Fully Defer Facility Investment Project

Exhibit 108 presents the geo-targeted DSM supply curve for a distribution system located in Union Gas' South region, where 43% of the peak hour demand is attributed to residential customers, while commercial and industrial customers account for 24% and 33% of peak hour demand, respectively. The current peak hour demand from the distribution system is approximately 16,900 m^3/h and is growing at an average rate of 550 m^3/h per year (or 2.6%). Based on information provided by Union Gas, the peak hour demand growth will need to be accommodated by a facility investment project that is anticipated to have a capital cost of approximately $14,100,000 for the installation of 7.6 km of an NPS 12 steel 6160 kPa pipeline.

In this scenario, there is not be enough DSM potential to offset the peak hour demand growth placed on the distribution system. ICF's analysis suggests that a geo-targeted DSM program would only be capable of offsetting growth by 366 m^3/h annually (or 1.7%).

Exhibit 108: Comparing Facility Investment with Geo-Targeted DSM in Union Gas' South Region (Case Study 3)



Although the 2.6% annual growth rate in peak hour demand prohibits a complete deferral of the planned facility investment, it is still possible to cost-effectively delay the project by one year by implementing a geo-targeted DSM program featuring only the most cost-effective measures at the beginning of the supply curve. The cash flows for the planned facility investment are compared to one and two-year deferrals in Exhibit 109.[118,119] Whereas a one-year deferral is cost-effective, a two-year deferral would require an additional $171K in annual DSM expenditures, rendering the deferral cost-ineffective.

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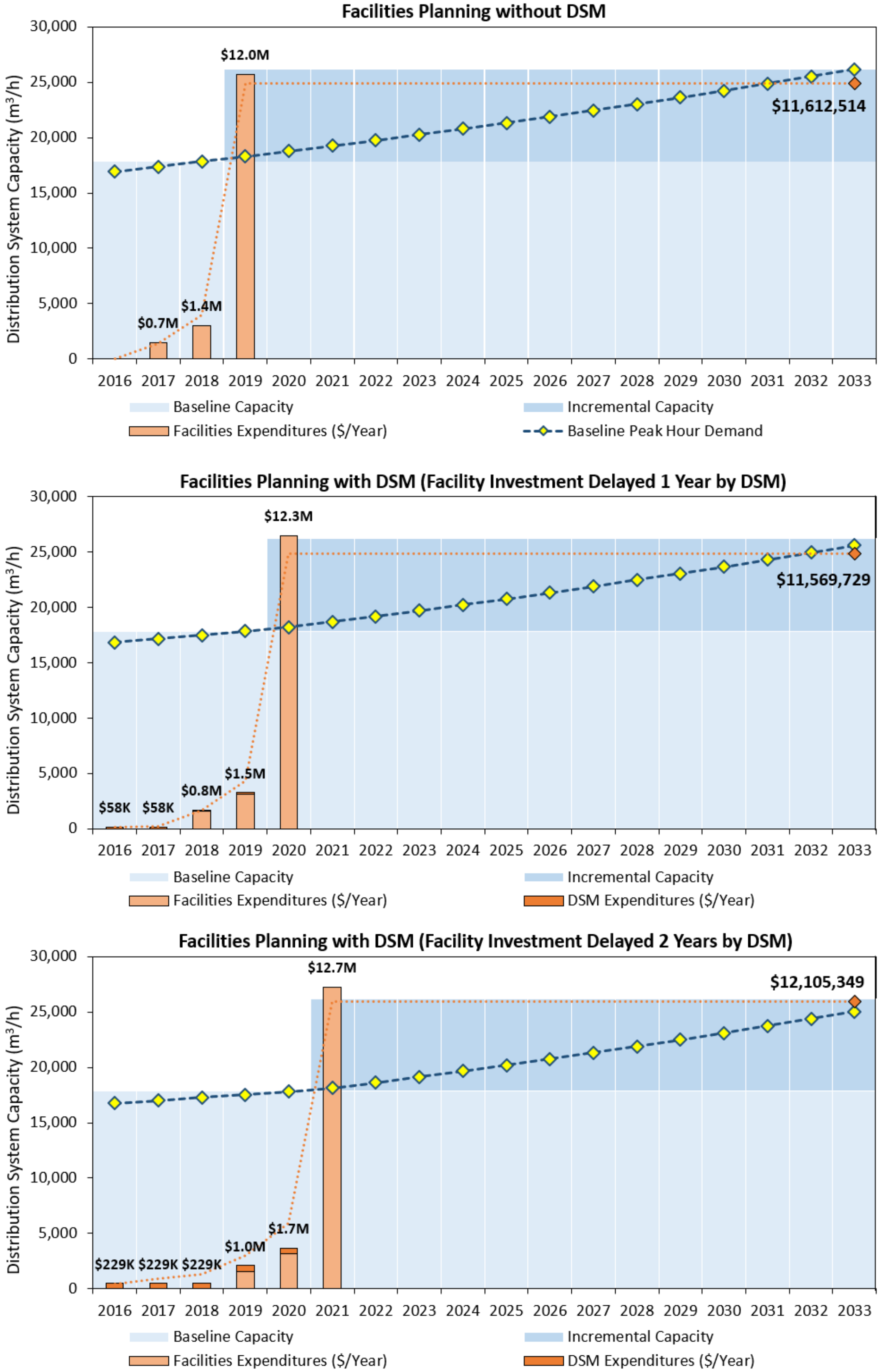
[118] Note that the capital costs of facility investments are assumed to increase by 3% for each year the project is deferred.
[119] Because annual DSM expenditures are significantly smaller than facility investments, it is difficult to discern the dark orange bars denoting DSM spending in Exhibit 109. For clarity, the center chart in Exhibit 109 (1 year delay of facility investment) shows annual DSM expenditures of $58K between 2016 and 2019 (inclusive), while the bottom chart (2 year delay of facility investment) shows annual DSM expenditures of $229K between 2016 and 2020 (inclusive).

Exhibit 109: Comparison of Facilities Planning Cash Flows with and without Geo-Targeted DSM (Case Study 3)



5. Intersection of Facilities Costs and DSM Supply Curves

The DSM supply curves reflect ICF's best current assessment of the costs and savings on peak hour demand available from DSM programs, while the geo-targeted DSM supply curves reflect the potential cost of serving incremental demand growth via investments in new facilities. As indicated in the DSM supply curve analysis results, there are a number of facility investments where the incremental cost of reducing load using geo-targeted DSM programs may be lower than the incremental cost of the facility when compared strictly on a \$ per m^3/h of incremental capacity provided. Hence, ICF's analysis of the potential for geo-targeted DSM to reduce peak hour demand growth suggests that under certain circumstances, there may be potential to reduce facility investments using geo-targeted DSM programs.

However, there are several factors that should be considered when making a project-specific comparison of the cost of geo-targeted DSM and the cost of new facilities. These include:

- Other benefits of facilities projects
- Reliability of DSM programs to reduce peak hour demand
- DSM penetration rates
- Size of the geo-targeted community
- Magnitude of expected peak hour demand growth to be served relative to the capacity of the planned facility

These factors allow for the characterization of the types of projects where geo-targeted DSM programs may be effective. Each of these factors is discussed below:

1) **Other benefits of facilities projects*:*** Many facilities projects provide additional reliability and flexibility to the natural gas distribution system in addition to increasing capacity, and most projects are designed to maximize these benefits. For projects where system reliability and flexibility are a significant factor in project design, the cost of the project needs to be allocated between the increase in capacity and the other project benefits, meaning that a geo-targeted DSM program that does not provide similar benefits would be of less value than the avoided facility project.

2) **Reliability of DSM programs to reduce peak hour demand:** To be useful in reducing facility investments, geo-targeted DSM programs must achieve the same level of reliability as the facility investments they are designed to reduce. In the short term, the uncertainty regarding the cost and reliability of geo-targeted DSM programs limits the Gas Utilities' ability to rely on geo-targeted DSM programs during infrastructure facilities planning. As the Gas Utilities implement and evaluate the in-field pilot projects designed to measure the peak hour demand savings of the DSM programs, and the results of pilot programs in other jurisdictions become available, the level of certainty regarding the potential for DSM to reduce facility investments will increase, and the level of risk associated with DSM as an alternative to infrastructure will decline.

   However, until the reliability of geo-targeted DSM programs as an alternative to facility investments is confirmed by pilot projects, the Gas Utilities will need to address DSM performance risk. Potential approaches to addressing this include:

- Plan to install more DSM than may be necessary in order to ensure that if the DSM programs underperform, the utility system remains sufficient to meet requirements
- Implement the geo-targeted DSM programs at an accelerated schedule to ensure that if the required reductions in peak hour demand are not achieved, the Gas Utilities still have sufficient time to build the necessary infrastructure
- Ensure that the progress of the geo-targeted DSM programs (i.e., measure participation, impacts, etc.) are sufficiently monitored on an on-going basis.

3) **DSM penetration rates**: ICF's analysis of DSM potential indicates that the cost of geo-targeted DSM programs will increase as the desired penetration rate for the program increases, and that there is likely to be a maximum cost-effective level of DSM program penetration. ICF's analysis also suggests that, on average, the achievable potential for annual peak hour demand savings is in the range of 1.2% of peak hour demand. As summarized in Section 1.2, ICF's analysis of the Gas Utilities' facility investment data revealed that, when measured by the amount of incremental capacity being added, only about 14% of Enbridge's planned facility investments fall below 1.2% annual peak hour demand growth, while only approximately 17% of Union Gas' planned facility investments fall below this critical level of growth. While facilities projects in areas with growth above this threshold can be temporarily deferred by DSM, they cannot be avoided indefinitely. It should also be noted that, aside from the limitations imposed by annual peak demand growth rates, the viability of geo-targeted DSM programs is further reduced by the fact that DSM may not be economical in all situations, especially for facility investments with lower than average capital costs.

4) **Size of the geo-targeted community**: As with all DSM programs, geo-targeted DSM programs will benefit from economies of scale. There are certain minimum requirements to set up an effective geo-targeted DSM program, including direct program costs, measurement and evaluation costs, and marketing and promotion costs. On a cost per program participant basis, all of these costs are likely to decline as the number of participants increases. As a result, as facility investments decline in size of capacity being added, the cost per m^3/h of peak hour demand savings is expected to increase, and smaller projects are unlikely to be cost-effective.

5) **Magnitude of expected load growth to be served relative to the capacity of the planned facility**: Facility investment costs tend to increase in a stepwise fashion. For example, if a new pipeline of any given size is insufficient to meet expected peak hour demand growth, the next option available to the utility is likely to be an increase in the pipe diameter. The incremental capacity provided by the next largest diameter of pipe tends to be much greater than the incremental cost of the larger diameter pipeline. As an example, increasing pipe diameter from 8 to 12 inches would typically increase the incremental capacity provided by the project by 125%, while costs would typically increase by about 10%.

   As a result, facilities that are sized to provide the lowest cost solution capable of meeting the expected peak hour demand growth can add significantly more capacity than is expected to be required with a relatively small incremental cost. Geo-targeted DSM programs are much more likely to be cost-effective when the expected peak hour demand growth is significantly less than the amount of capacity added by the project, rather than a facility investment where the expected load peak hour demand growth completely utilizes the capacity of the planned project. For example, a geo-targeted DSM program designed to reduce peak hour demand sufficiently to allow an NPS 12 pipe to be reduced to an NPS 8 pipe is more likely to be cost-effective if the expected peak hour demand growth is only slightly greater than the amount of capacity that could be provided by the NPS 8 pipe, as compared to a project where the full capacity of the NPS 12 pipe is expected to be utilized.

Hence, geo-targeted DSM programs are most likely to be both cost-effective and practical when the expected peak hour demand growth is only marginally greater than the threshold necessary to trigger a new investment or to require a larger size diameter pipeline. Projects that are expected to barely meet projected requirements are less likely to be cost-effectively reduced by geo-targeted DSM.

VI. Conclusions and Recommendations

This study provides a comprehensive assessment of the potential to use broad-based and geo-targeted DSM as part of facilities planning. The study includes a review of industry experience, an overview of the facilities planning process, an assessment of the potential impact of DSM programs on peak hour demand, the potential to use DSM to reduce new investments in utility infrastructure, and a review of the policy changes that would facilitate the incorporation of DSM into the facilities planning process. The primary conclusions of the study were developed based on the findings discussed earlier in this report, and are summarized below.

1. Industry Experience using DSM to Reduce Facility Investments

ICF's review of existing DSM programs at North American gas utilities in other jurisdictions (documented in Section II) found that little to no activity has been undertaken that was designed to reduce natural gas transmission and distribution costs using targeted DSM and demand response (DR). In addition, the measured data needed to determine the potential impacts of DSM on new facilities requirements is generally unavailable. Overall, the review of industry experience found that:

1) 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. ICF's review of existing DSM programs in other jurisdictions found that no activity has been undertaken that was designed to reduce facility investments using targeted DSM and DR.
   - 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 this study was initiated in October of 2016, a few gas utilities have begun to consider these impacts. However, these efforts remain in the very early stages.
   - Gas utilities in other jurisdictions have 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.[120]

2) ICF also assessed activity in the electric power industry. While some progress has been made in that industry to defer transmission and distribution costs using targeted energy efficiency, differences in utility cost structure, duration of peak period requirements, and availability of data on DSM impacts leads ICF 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.

   The differences between the electric and natural gas systems include:

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[120] Note that, to date, no natural gas utilities have actually measured the impact of DSM programs on peak period demand.

- The electric industry can achieve greater infrastructure cost savings from similar DSM and DR measures, due to the higher cost infrastructure of the industry. The principal infrastructure reduction is generating capacity. Reducing peak electricity demand translates readily to lower generation and the avoidance of building new power plants.
- The difference in risk tolerance between the industries for capacity shortage also increases the attractiveness of DSM and DR for infrastructure reduction in the electric industry relative to the natural gas industry.
- The ability to accurately measure the impact of DSM due to the advanced metering capabilities of electric utilities reduces the risk associated with a reliance on DSM to displace electricity infrastructure. The lack of metered customer data makes estimating peak hour demand savings difficult for gas utilities and increases facilities planning risks.

2. Assessment of the Potential to Reduce Facility Investments

2.1 Critical Elements of the Facilities Planning Process

Section III of this report provides an overview of the facilities planning process. However, there are a few important principles that impact the potential for DSM programs to reduce facility investments. These include:

1) **The primary goal of facilities planning is to ensure that the utility infrastructure is reliable.** Facilities must be of sufficient size and installed at the appropriate time to provide reliable natural gas service during peak demand periods[121] at system design conditions consistent with reasonable costs. Failure to meet peak period demands imposes considerable safety risks, and could result in loss of gas supply to firm utility customers during extreme cold conditions, leading to societal and economic costs to the utilities and their customers. As a result, the Gas Utilities have economic and societal incentives to develop infrastructure based on upside uncertainty in the forecast rather than downside uncertainty.

2) **The facilities planning process requires significant lead time.** The principal facilities are pipelines, often in urban settings, that entail high costs and potential local disruption. This requires significant advance planning to ensure that facilities are available by the time that they are needed. The facilities planning process is designed to identify expected

[121] The peak demand period for facilities planning used in our analysis is the peak hour, which typically occurs during the morning period between 7 and 9 a.m. For planning purposes, the peak period demand is projected based on design day weather conditions, which typically occur on the coldest anticipated winter day, or design day. The duration of the peak period considered in the planning process depends on the type of infrastructure being evaluated. For individual service connections, the peak period used to size the service connection should be sufficient to meet the maximum customer demand. For certain facility investments serving a limited number of customers, the peak period used for facilities planning may need to be as short as 15 to 30 minutes, while larger transmission assets may be planned based on a longer time frame, potentially a 24-hour design day.

requirements about five years prior to the time the capacity will be needed to allow sufficient time for the project planning and design, regulatory review, and construction to be completed.

3) **There are significant economies of scale associated with the construction of facility investments.** The cost of the incremental unit of capacity declines as the size of the project increases due to efficiency in planning, right-of-way and easement availability, mobilization costs, and labour and materials costs. As a result, downsizing a specific project is likely to lead to only modest cost savings. In addition, if a project proves to be undersized relative to future system growth, additional facility investments are likely to be much more expensive than increasing the size of the initial project.

4) **Facilities costs vary widely depending on specific circumstances:** The ability to cost-effectively reduce facility investments through the use of targeted DSM programs depends on the cost of the infrastructure that can be reduced, which varies significantly based on the size of the project, the characteristics of the existing system, and the areas impacted by the project. As a result, the cost-effectiveness of DSM programs as an alternative can differ widely for different facility investments.

2.2 Potential for Targeted DSM to Impact Distribution Facility Investments

This study has focused on distribution facility investments; large scale transmission facilities (such as Union Gas' Dawn Parkway where investment is driven primarily by contractual support for the project) and projects such as the Enbridge GTA (which was driven primarily by the need to upgrade the gas distribution system rather than by growth in demand) were outside the scope of this study.[122]

Due to the lack of industry experience, and the absence of measured data on DSM peak period load impacts, ICF conducted most of its research into the potential for DSM to impact distribution company infrastructure requirements by extrapolating existing data on DSM program impacts from annual consumption to peak hourly demand based on building modeling, and other theoretical analysis. While we view the analysis as robust, there remains uncertainty, particularly on the cost and reliability of using DSM to reduce distribution facility investments. Hence, our conclusions should be treated as preliminary until additional research is completed.

The assessment of the potential for DSM to impact facility investments is reviewed in Sections IV and V of this report. ICF's primary conclusions are summarized below.

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[122] Most transmission system investments are being driven by firm transportation (FT) customer demand. In-franchise FT customer demand is less amenable to DSM than general services demand, and many FT customers are unwilling to release capacity even if demand declines due to the potential lack of availability of capacity, or higher cost of capacity in the future. Ex-franchise customer demand would not be amenable to utility DSM programs. To the extent that general services demand served by these facilities could be reduced through DSM, the demand for new transmission facilities cold be reduced; however, given the relatively small share of general service demand growth driving most transmission projects, the potential for DSM programs to delay or reduce investments in transmission infrastructure is expected to be limited.

1. **DSM can impact peak hour natural gas demand and natural gas demand growth.** ICF's analysis indicates that many, but not all, DSM measures can be expected to have measurable impacts on peak hour natural gas demand:
    - In general, industrial measures are most cost-effective at reducing peak hour demand, followed by commercial and residential sector measures.
    - Space heating is important from a peak hourly demand perspective, even in the industrial sector. Measures that result in space heating savings, such as air sealing, insulation, central heating systems and boiler measures, contribute disproportionately to peak hour demand savings.
    - Adaptive thermostats lead to annual gas consumption savings but initial analysis shows that this measure may increase peak hour demand since HVAC systems are recovering from temperature setback during this period.
        - Residential building modeling indicates that adaptive thermostats lead to a significant increase in peak hour demand. This occurs because the thermostats aim to raise building temperature quickly to compensate for the lower nighttime temperature setting.
        - Commercial building modeling suggest that adaptive thermostats lead to increases in peak hour demand as well, but the impact is much smaller than in the residential sector due to the lower applicability of the measure in the commercial sector and the diversity of operating schedules in the different types of commercial building types considered.
        - Adaptive thermostats also lead to increased demand during other non-setback hours on the peak day since it can take several hours to heat up a building's entire thermal mass.
    - At least a portion of the demand impacts from other measures with a controls component may not be coincident with peak hour demand.
    - Modeling of tankless water heaters suggests that they can increase peak demand for an individual customer during the relatively short periods that they are in use. However, when impacts are considered on an hourly basis and aggregated across many customers within a community (i.e., such that the diversity of water usage profiles are considered), tankless water heaters are expected to lead to peak hour demand reductions.
    - Based on ICF's building modeling, DSM is not expected to shift the timing of the peak hour demand from the period of significance (peak period #2) to another time.

2. Based on ICF's initial assessment of the potential to reduce peak hour demand using DSM, it appears possible that some facility investments may be reduced through the use of targeted DSM.
    - ICF's analysis suggests that geo-targeted DSM programs would have the potential to offset peak hour demand growth by up to about 1.2% per year, before consideration of DSM program and measure costs.
    - ICF's analysis suggests that DSM may be able to cost-effectively reduce facility investments in certain situations where annual peak hour demand growth is relatively low and project costs per unit of peak hour demand are relatively high.

3. Based on ICF's initial assessment of the likely costs of reducing peak hour demand using DSM, the number of facility investments that appear likely candidates for being delayed or reduced in size by targeted DSM is expected to be limited.
   - Opportunities to reduce facility investments in a cost-effective manner through the use of geo-targeted DSM are likely to be limited because the cost of geo-targeted DSM programs are higher than many facility investments.
   - The maximum penetration rate of DSM programs appears likely to be lower than the rate of growth in most of the areas where a significant share of new facility investments are indicated. More than 80% of the Utilities' planned investments are intended to serve regions where load growth exceeds the DSM potential threshold of 1.2% per year. Hence, ICF's analysis of the Gas Utilities' initial facility investment plan suggests that, even before cost considerations, DSM potentially could avoid less than 20% of the Gas Utilities' planned investments
   - As a result, DSM programs targeted at facility investments in these regions may be able to delay a specific project, but are unlikely to be able to eliminate the need for the facility investment altogether. The cost-effectiveness of geo-targeted DSM programs decreases as the delay in project implementation becomes shorter.
   - There is likely a minimum size for facility investments where geo-targeted DSM programs could be cost-effectively implemented due to DSM program development, implementation, and monitoring costs.

3. Summary of Information Needs

3.1 Policy and Planning Changes Needed to Facilitate Use of Targeted DSM to Reduce Facility Investments

Facilities planning and DSM planning processes are currently independent of each other and operate under different regulatory structures. Given the range of differences between the existing DSM planning process, and the needs and objectives of the facilities planning process, it is likely that implementation of geo-targeted DSM will require a specific planning and regulatory framework, and be developed for the express purpose of reducing natural gas infrastructure.

Integrating the potential for DSM to reduce infrastructure requirements into the facilities planning process will require changes in policy, as well as changes in the facilities and DSM planning processes. ICF's primary conclusions include:

1. Changes in Ontario energy policy and utility regulatory structure would be necessary to facilitate the use of DSM to reduce facility investments. These changes would include:
   - Cost recovery guidelines for overlapping DSM and facilities planning and implementation costs, and criteria for addressing DSM impact risks.
   - Approval to invest in, and recover the costs of the AMI necessary to collect hourly data on the impacts of DSM programs and measures.
   - Changes in the approval process for DSM programs to be consistent with the longer lead time associated with facilities planning.

- Clarification on the allocation of risk associated with DSM programs that might or might not successfully reduce facility investments.
- Guidance on cross-subsidization and customer discriminations inherent in geo-targeted DSM programs that do not provide similar opportunities to all customers.
- Guidance on how to treat conflicts between DSM programs designed primarily to reduce investment in new infrastructure and DSM programs designed to reduce carbon emissions or improve energy efficiency.
- Guidance on how to treat uncertainty associated with energy-efficiency programs outside the control of the Gas Utilities that impact peak hour and peak day demand.

2. There are a number of differences between the DSM and facilities planning processes that must be reconciled to factor in geo-targeted DSM to reduce facility investments.
   - Differences in risk and reliability criteria, cost-effectiveness criteria, program assessment and planning timeframes.
   - The linkages between DSM planning and facilities planning are currently passive rather than active, and are not sufficient to actively integrate geo-targeted DSM programs into the facilities planning process.
   - Underestimating facilities requirements can lead to significant operational problems (e.g., widespread customer outages during cold weather), leading to a risk adverse planning process for facility investments. Given the lack of data on the actual impacts of DSM measures on peak hour demand, DSM is generally considered a high-risk alternative to facility investments that would be inconsistent with facilities planning criteria.

4. Recommendations for Additional Research

The use of DSM to reduce facility investments remains relatively untried and untested. While ICF has identified areas where there is potential to use DSM to reduce facility investments, there remains uncertainty in both the potential and the cost of achieving that potential. There is little to no actual measured data on DSM program impacts on peak period demand for natural gas, and there are no real world examples that ICF can point to that indicate that DSM can be used effectively for this purpose.

As a result, the fundamental disconnect between the limited risk acceptable to the Gas Utilities in the facilities planning process and the lack of information on the ability of DSM to reliably reduce peak period demand needs to be addressed before the Gas Utilities would be able to rely on DSM to reduce facility investment as part of the standard utility facilities planning process.

- The lack of actual measured hourly data at the customer level creates uncertainty in the evaluation of the potential to use DSM to reduce facility investments and increases the risk (and cost) of using DSM to reduce facility investments.
- The lack of reliable implementation cost data for geo-targeted DSM programs makes accurate cost comparisons between facilities and DSM difficult.

Hence, one of the most important conclusions from this study is that ***additional research is necessary before the Gas Utilities would be able to rely on DSM to reduce new facility***

investments as part of the standard utility facilities planning process. This research needs to include:

- **Collection of hourly demand data:** The collection and evaluation of measured hourly demand data at a customer level to more accurately assess the impact of DSM measures and programs on peak period demand is needed to determine the cost and implementation potential of DSM measures and programs. This will require AMI and automated meter reading (AMR) capability. Until actual hourly data is available, the Gas Utilities will not be in a position to accurately determine the potential cost-effectiveness of using DSM as an alternative to facility investments.
- **Assessment of the reliability of using geo-targeted DSM to reduce peak hour demand growth:** The risk associated with relying on DSM to reduce peak hour demand is one of the major difficulties in using DSM to reduce facility investments. ICF expects that development of specific in-field pilot studies that test the ability of the utility to offset peak hour demand growth using DSM pilot programs will be the best approach to resolving these issues.
- **Assessment of the cost of geo-targeted DSM implementation:** The cost per participant of implementing geo-targeted DSM programs is expected to be higher than the costs of implementing system-wide DSM programs. The additional costs are based on the smaller program scale associated with geo-targeted DSM programs, the tailored nature of these programs, and the need for additional monitoring and evaluation. Based on available information, and on our experience with DSM program implementation, these costs are estimated to be 1.5 to 2 times higher than typical DSM program costs. However, until actual data from in-field pilot studies is available, the actual increase in costs will be unknown. The magnitude of these costs may determine whether or not geo-targeted DSM programs can be cost-effective.

Appendix A Utility Transition Plan

Transition Plan

January 2018

Table of Contents

Introduction:

Integrated Resource Planning ("IRP") refers to a multi-faceted planning process that includes the identification, preparation, and evaluation of all realistic supply side and demand side options in order to determine the least cost for customers and lowest risk approach to addressing transmission and distribution infrastructure ("infrastructure") requirements. This could include a review of a variety of different low carbon options such as energy efficiency to defer existing regional and local infrastructure; the impact of net zero ready subdivisions; distributed energy resources (i.e. renewable natural gas); community energy planning; and the least cost lowest carbon solutions. IRP could also focus on the interplay of these various energy options and the subsequent impact on infrastructure to meet system demand.

The Enbridge / Union Gas IRP Study upon which this Transition Plan is based, considers a component of Integrated Resource Planning, specifically, if and how the implementation of Demand Side Management ("DSM") may be used to defer or eliminate the need for infrastructure development. ICF, a well-known energy conservation consulting firm was engaged by the utilities to undertake the study. The findings from ICF's work are summarized in Table 1 below and explained in more detail in the Executive Summary, these findings have been helpful to the utilities in developing this Transition Plan. The findings also point to the necessity for more insight, including the completion of the currently underway in-field case studies in order to come to any definitive conclusion about traditional DSM's role in supply planning. Over time, IRP may evolve to consider other scenarios that provide cost effective, safe, reliable and low carbon impact solutions.

Regardless, the utilities paramount obligation is to deliver safe and reliable energy to our customers. As such, a measured and fact-based approach is critical to any planning considerations.

Table: 1

	IRP Study Conclusions:
1	Based on ICF's initial assessment of the potential to reduce peak hour demand using DSM, it appears possible that some infrastructure investments may be reduced through the use of targeted DSM.
2	Changes in Ontario energy policy and utility regulatory structure would be necessary to facilitate the use of DSM to reduce infrastructure investments.
3	Changes in utility planning processes would be necessary to facilitate the use of DSM to reduce infrastructure investment.
4	Additional research is necessary before the Gas Utilities would be able to confirm DSM could reduce infrastructure investments.

This document serves as the utilities' Transition Plan and outlines the roadmap for IRP development over the next few years. As with any roadmap it is intended to be a starting point for clarity around activity and outcomes, but is anticipated to evolve. The utilities are undertaking case studies to test in field the conclusions of the IRP study and inform the transition to IRP as well. In addition, to the activities outlined in this Transition Plan, the utilities continue to analyse and plan for traditional infrastructure requirements, low carbon solution development including behind-the-meter options, and energy efficiency results.

Background – The Regulatory History of IRP and DSM in Ontario:

IRP has been considered in the regulatory environment in Ontario since the early 1990s. In 1991, the Ontario Energy Board ("the Board") issued a Discussion Paper prior to commencing a generic proceeding into Least Cost Planning (later renamed Integrated Resource Planning).

Although the supply and demand side options considered within IRP can be quite broad, in recent years, much of the discussion has focused on the impacts of Demand Side Management (DSM) and energy efficiency. Between 1995 and the present, the gas utilities in Ontario have engaged in DSM activities, generating significant natural gas savings and have provided passive infrastructure savings by reducing demand in a broad based system wide context.

Specifically, attention was given to energy efficiency's potential role, in the context of geo-targeted infrastructure planning during EB-2012-0451 the Enbridge GTA Reinforcement Project.

The 2015-2020 DSM Multi-year Plan Decision directed that:

> "Enbridge and Union to work jointly on the preparation of a proposed Transition Plan that outlines how to include DSM as part of future infrastructure planning activities. The utilities are to follow the outline prepared by Enbridge, and should consider the enhancements suggested by the intervenors and expert witnesses. The Transition Plan should be filed as part of the mid-term review""

Further, in the OEB direction letter dated June 20, 2017, with respect to the DSM mid-term review, the Board directs the utilities in the second requirement due January 15, 2018, and as outlined on page 4 "to submit a transition plan to incorporate DSM into infrastructure planning activities."

Transition Plan Purpose:

This Transition Plan serves to meet the Board's filing requirement, and is a companion document to the IRP Study Executive Summary Report. The Transition Plan lays the pathway for considering IRP over the coming several years focusing in the shorter term on the specific role of energy efficiency in supply planning and in the longer term may serve as a foundation for a broader approach to IRP. The utilities believe this roadmap will aid in the coordination between distribution planning processes and analysis, and low carbon alternatives including energy efficiency.

Transition Plan Objectives:

As noted above, the Board directed the utilities to file an IRP Transition Plan as part of the DSM Mid-Term Review that "outlines how to include DSM as part of future infrastructure planning activities"[1].

The Transition Plan's objectives are to:

- Identify the process phases that the utilities will move through to ensure implementation of a formalized IRP process including DSM as per the Board's direction,
- Indicate how the utilities will internally organize to ensure that DSM is a consideration in infrastructure planning,
- Indicate an internal governance structure to ensure the implementation of an IRP planning process.

IRP Study Scope /Outline:

The Enbridge / UG IRP Study provides insight on what IRP may include for natural gas utilities, how it may function, and some analysis on possible outcomes. The utilities recognize that Integrated Resource Planning will require more formalized consideration to optimize safe, reliable, cost effective and low carbon energy solutions for our customers.

The IRP Study assesses if and how energy efficiency can be leveraged by Enbridge and Union Gas to potentially avoid, defer or reduce future geo targeted gas infrastructure investment. In the future, treating IRP with a broader brush by introducing not just a binary discussion around demand and supply planning for natural gas, but also a diversified range of energy solutions and scenarios that may include energy efficiency, demand response, renewable energy or distributed energy systems among others, may be necessary to contribute towards carbon reduction targets. Broader IRP planning may constitute a next phase to this transition and analysis work.

The Study as scoped focused on three areas of overlap (intersections) between DSM planning and infrastructure planning:

Intersection 1: Broad based DSM and Distribution Infrastructure Planning
Intersection 2: Subdivision and New Community Planning
Intersection 3: Targeted DSM and Reinforcement Projects

Planning Processes:

The utilities DSM and Infrastructure planning processes are currently informally integrated and to move to an IRP process, these two processes would require a more systematic, formalized and comprehensive integration.

DSM Planning Process: The utilities DSM planning processes and programs reflect the Board's DSM Framework, and related Decisions, as well as continuous improvement driven by the utilities learnings over time. The Board's DSM Framework measures and incents reduction of annual gas consumption throughout Ontario, with the ultimate goal being to ensure that savings are verified and achieved efficiently while customers receive "the greatest and most meaningful opportunities to lower their bill by reducing consumption."[2] Put another way, DSM focuses on broad based annual savings across the

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[2] Report of the Ontario Energy Board 2015-2020 Natural Gas DSM Framework Page 1

franchise areas that drive maximum bill reduction, versus a jurisdictionally bound, peak hour load reduction to influence supply planning.

Currently, the natural gas DSM plans inherently account for potential savings in system wide infrastructure created by DSM savings through avoided distribution costs. Avoided costs include costs such as capital for distribution infrastructure and operating costs, avoided demand-side costs such as operation costs, and storage costs, transportation tolls and demand charges. As part of the IRP Study there are considerations given to determining the avoided reinforcement distribution costs on a geo targeted basis, as this helps to inform the potential of DSM to defer infrastructure, also sometimes referred to as active (geo targeted) deferral.

Infrastructure Planning: Infrastructure planning is based on a long term load forecast intended to identify potential system constraints leading to incremental infrastructure requirements and to develop these plans prior to the need for new infrastructure. The primary goal of infrastructure planning is to ensure that the utilities' infrastructure is sufficiently robust to provide reliable and safe natural gas service that meets the design condition peak hour requirement forecast, consistent with reasonable costs. The utilities are also bound by certain design parameters with respect to its natural gas distribution and transmission systems, these design parameters ensure the safe and reliable delivery of natural gas to its customers.

The impact of broad based DSM programs on infrastructure investment is inherently captured in the infrastructure planning process. Historical gas throughput is used as a base to predict future consumption and is updated each year. These historical forecasts include changes in gas usage resulting from implementation of historical DSM measures, as well as other natural conservation factors such as improved building codes, and higher energy efficiency standards for natural gas equipment. The infrastructure plans do not explicitly factor in future projections of DSM program effects on peak day or peak hour demand. Network analysis and infrastructure planning adjusts its forecast in gas demand on a regular basis to ensure trends are reflected in the most recent results. Reinforcements are only executed when needed and the scope is adjusted as required. To put this into context the reinforcement expenditures for both utilities, on average over ten years, is approximately 13% - 15% of the total forecasted capital expenditures.

Previous and Current Planning Processes:

DSM and infrastructure planning processes have occurred somewhat independently in the past for both utilities. These processes have worked well and have provided for both the accurate management of DSM budgets and annual / cumulative savings targets on one hand, and the infrastructure planning process that has allowed for a robust, safe and reliable distribution system on the other. Both of these planning processes support the Ontario Energy Board's Consumer Charter which amongst other Consumers rights, indicates that Consumers have the rights to a safe and reliable service, as well as the right to access available energy conservation programs.[3]

[3] https://www.oeb.ca/consumer-protection/how-we-protect-consumers/consumer-charter

Moving forward, IRP affords the utilities the opportunity where appropriate to coordinate and integrate the processes between demand and supply in infrastructure planning. A more systematic IRP process may require new and evolved processes as well as incremental resourcing or technology infrastructure such as installation of advanced metering infrastructure to provide automated metering. The utilities are committed to a transition to IRP and see the opportunities from a due diligence and continuous improvement process model, recognizing that benefits may result from both the review and integration of the various planning processes. As more is known about how energy efficiency, demand response and carbon policy impact the natural gas distribution system, outcomes may not be as straightforward as anticipated. For example, if there is a GHG reduction program that decreases annual load but at the same time increases peak hour, infrastructure requirements may need to adjust to ensure the safe and reliable delivery of natural gas to customers. In particular, the IRP Executive Summary outlines that adaptive thermostats decrease annual electric and gas load, but actually increases winter peaking load for the natural gas utilities. This means that while carbon reduction goals are being met, incremental infrastructure may be needed to meet the higher winter peaking requirements

Future Integrated Planning Processes:

Continued analysis and monitoring of DSM programs and higher energy efficiency equipment, as well as any subsequent impacts of these initiatives on peak period demand should be conducted and factored into infrastructure requirement planning and forecasting processes.

The current in-field case studies being completed in the market by both utilities will further inform the IRP Study findings by creating more understanding of the impacts of broad-based DSM programs and technologies on peak hour demand. Using this information, the utilities will be able to make informed decisions, based on cost benefit analysis using the appropriate avoided distribution costs to more accurately identify those infrastructure projects that have a potential to be deferred by the implementation of targeted DSM programs. Where possible, alternative lower carbon energy solutions may be considered. All of this would need to be done with consideration to customers' energy bill impacts.

The utilities recognize that the certainties required for infrastructure planning on actual peak hour demand resulting from higher efficient equipment will need to have a high degree of accuracy. The utilities will consider further research including load research and technology assessment and analysis to ensure that there is an ongoing continuous improvement cycle of the information and assumptions used in the IRP process.

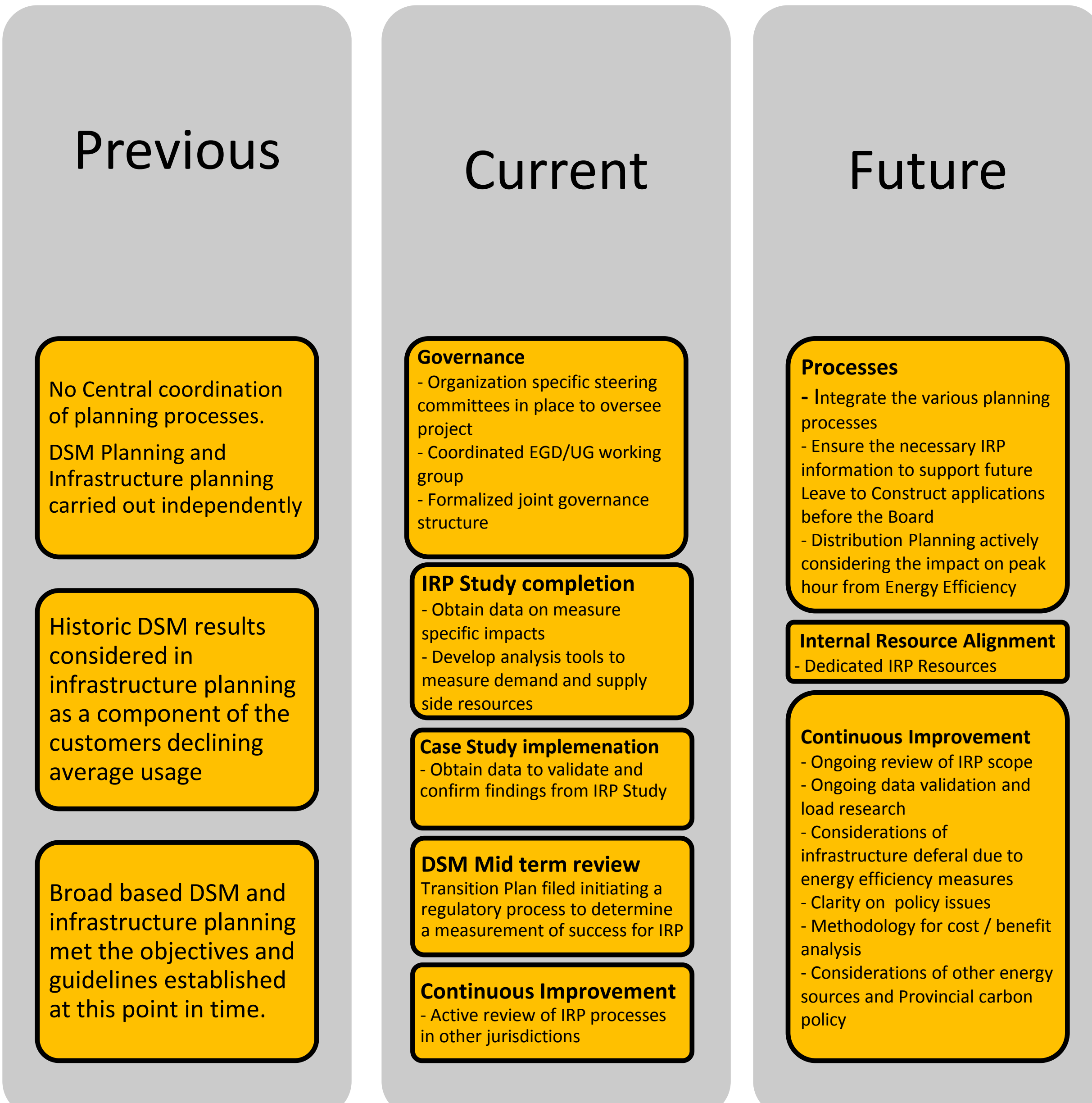
In order to stay abreast of industry best practices, the utilities will monitor on a continuing basis, industry best practices and the enhancements to Natural Gas IRP in North America as well as participate in and / or establish industry and utility groups that are looking at Natural Gas IRP, and broader energy pathway discussions. Moving forward into an IRP model affords the opportunity to review, coordinate and integrate processes between demand and supply in infrastructure planning.

Underscoring all of these activities will be the evolution and implementation of the Province's climate change and related carbon policies and spending, recognizing that the Government's priority of reducing

GHG emissions may necessitate consideration of IRP priorities and processes. The dynamics between energy efficiency's impact on peak demand and the distribution system, versus the annual savings and reduced GHG emissions would need to be fully understood. Put another way, there will need to be consideration given to whether there is alignment moving forward around carbon planning and integrated resource planning, and if there is not alignment, which will take priority?

Elements of the planning processes are identified in Figure 1, highlighting the progression of planning from its previous process to the utilities current IRP activities and future considerations.

Figure 1:



Integrated Resource Planning Transition Roadmap:

The Transition Roadmap initially spans over the next few years to accommodate the desktop review/paper portion of the IRP Study, the anticipated regulatory process and the more time intensive in-field case studies.

Phase 1 – 2017:

- IRP Study ongoing,
- Joint utility Working Group created pre-2017, remains in place to support implementation of the IRP Study completion and ensure timelines and deliverables completed,
- Joint utility Steering Committee assembled to provide governance and oversee implementation of IRP Study,
- IRP in-field case studies designed and initiated,
- AMR metering installed in case study areas in time to record winter customer usage patterns.

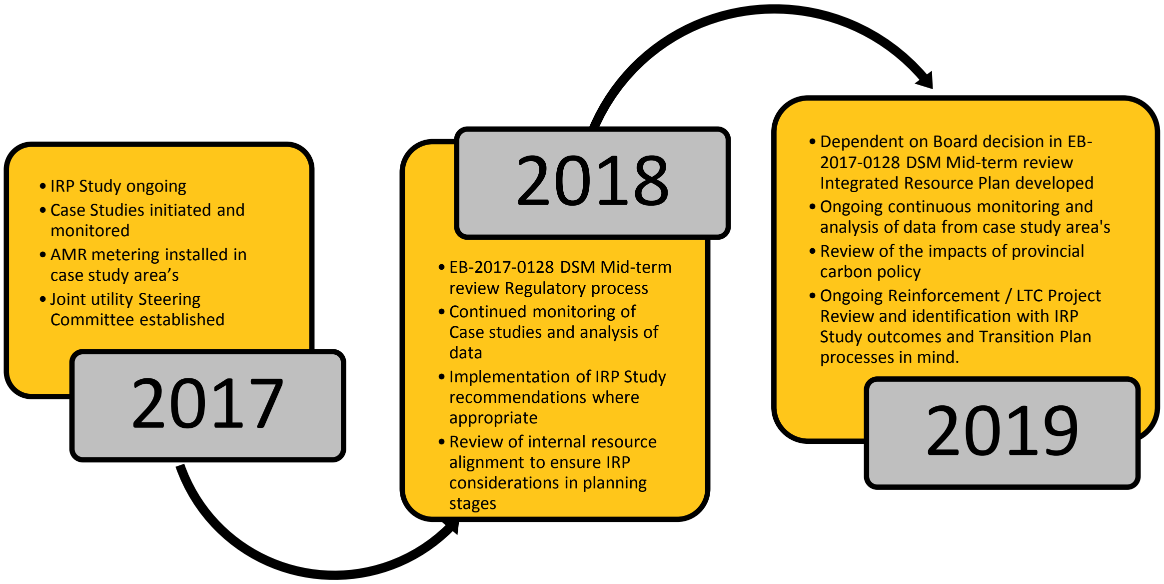
Phase 2 – 2018:

- IRP Study Executive Summary and Transition Plan filed during EB-2017-0128 DSM Mid-term review, joint utility Working Group to support and participate in all regulatory processes related to the Transition Plan and IRP Study,
- Continued monitoring and analysis of in-field case study findings, reviewing both DSM participants and non-participants,
- Identification of resourcing and infrastructure necessary to implement any IRP Study recommendations,
- Implementation of IRP Study recommendations that do not require additional resources or infrastructure where appropriate,
- Monitoring of Provincial carbon policies and funded energy efficiency programs, CDM activity, to identify if any, the impacts on infrastructure planning and design.

PHASE 3 - 2019:

- Dependent on the direction received from the Board during the EB-2017-0128 DSM Mid-term review, begin process of developing an Integrated Resource Plan which may include identifying necessary resources, data or enabling technology infrastructure requirements,
- Continued consideration of scope of IRP,
- Continued monitoring and analysis of data gathered from AMR metering from in-field case studies where DSM measures have been and are still being installed,
- Ongoing Reinforcement / LTC Project Review and identification with IRP Study outcomes and Transition Plan processes in mind,
- Consideration of the impacts of Provincial carbon policies, programs and regulations.
- Continued monitoring (and possible completion) of in-field IRP case studies.

Figure 2:



Governance Structure:

A key component of the integration of IRP at the utilities is ensuring that the senior management of both utilities is engaged, informed and aware of the IRP roadmap and phases to implementation. In moving forward with the IRP Study implementation, and to ensure continued collaboration a joint Utility IRP Steering Committee made up of Vice Presidents from both organizations will provide oversight, policy direction, and advise on an appropriate organizational structure in keeping with greater corporate goals.

The primary function of the joint IRP Steering Committee will be to oversee completion of the IRP Study in the short term, and provide long-term stability for IRP development at the utilities.

The IRP Steering Committee will be tasked with approving major IRP related development elements such as:

- Deliverables as identified in the IRP Study,
- Ensure the objectives meet the OEB requirements and customer/stakeholder interests,
- Budget, ensuring that effort, expenditures and changes are appropriate to ensure IRP integration,
- Risk management strategies, ensuring that strategies to address potential issues with the IRP processes have been identified, estimated and approved, and that the issues are regularly re-assessed,
- Understand how IRP aligns with corporate objectives, and,
- Define what success looks like and ensure measures are implemented which track progress.

Summary and Next Steps:

This Transition Plan outlines how the utilities will move forward with development and implementation of IRP including consideration for its ongoing governance. A summary of results of the IRP Study are included in the Executive Summary, along with information on next steps for future consideration of the utilities.

Appendix B References: Review of Industry Experience

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STAFF INTERROGATORY # 14

INTERROGATORY

Ref: I.EGDI.SEC.1
I.EGDI.SEC.3

Preamble:
Enbridge says that "The growth information provided to ICF was originally the best available information at the time and was based on 2016 projections and included Hemson growth forecasts."

Question:
Did ICF rely exclusively on the growth information provided by Enbridge, or did it prepare an independent growth forecast?

RESPONSE

ICF relied on the growth information provided by Enbridge.

STAFF INTERROGATORY # 15

INTERROGATORY

Ref: I.EGDI.SEC.1, Attachment 2, page 2

Preamble:
Enbridge indicates that its Long Range Planning (LRP) methodology changed between 2016 and 2017/2018, and that the updated methodology used updated information from more timing and geographically relevant Developer and Municipal plans. For example, Enbridge says the franchise-wide longer-term economic growth data provided by Hemson Consulting did not include information about possible high-rise developments."

Questions:
a) Please describe the key differences between Enbridge's 2016 and 2017/2018 LRP methodologies.
b) Please provide copies of the relevant Developer and Municipal plans.

RESPONSE

Enbridge believes it is important to first note that the preamble to this interrogatory does not accurately capture what was stated in evidence at the evidentiary reference noted. The evidence at this reference reads: "For instance, in the Bathurst LTC, information (i.e. additional data points) around possible high rise development that was not fully factored in Hemson's longer-term view of growth was built into the planning forecasts."

a) Enbridge's 2016 LRP was developed relying largely on long term organic growth forecasts provided by a third party. The 2016 LRP did not consider or incorporate specific development proposals which can aid in refining forecasts on a short-term basis. Improvements made in the 2017/18 LRP layers on development proposal data to inform short term system needs while still relying on third party data to inform long term customer growth. Please also see the response to OEB Staff Interrogatory #18 found at Exhibit I.EGDI.STAFF.18.

b) Information derived from the plans noted above is housed directly in the Company's GIS systems. The plans requested are numerous (estimated at approaching 80) and include all submitted proposals, ranging from significant commercial developments to minor alterations to single-family residences. As a result, the requested material is not readily available and would require significant time and effort to retrieve. Further, the Company submits that these plans indicate only the existence of proposed short term developments which in and of themselves do not inform a long term forecast nor do they translate directly into a natural gas load requirement. In light of the effort required to retrieve these significant materials and their questionable relevance to this proceeding, the Company respectfully declines to fulfill this request.

STAFF INTERROGATORY # 16

INTERROGATORY

Ref: I.EGDI.SEC.1, Attachment 2, page 3

Preamble:
Enbridge says that the area of impact considered in the planning process was expanded to account for increased growth in upstream development contributing to lower inlet pressures downstream. Enbridge provided a map illustrating the extents of the revised area of impact.

Questions:
Please provide a list of all pressure regulating stations off the high-pressure system serving the revised area of impact. For each station, please:
a) Identify its minimum allowable inlet pressure.
b) Provide ten years of history with respect to the lowest inlet pressure it experienced in each year.
c) Provide its forecasted minimum inlet pressure for each of the next five years assuming the Project is not constructed in any of those years.

RESPONSE

a) The stations identified below feed into the network in question. While this interrogatory asks for the minimum allowable inlet pressure (a design constraint) at each station, the Company's safe and reliable operation instead relies on the network in its entirety operating nominally at 55 psig. As a result, the technical specifications of each station itself are individually not relevant. What is relevant for the purposes of operations is the Forecasted Minimum Inlet pressure for 2017/2018 for each station. These are provided below. The figures below are the expected inlet pressure at design day, which is more representative of the operational status of the downstream network. Please see the response to OEB Staff Interrogatory #18 found at Exhibit I.EGDI.STAFF.18 for further discussion of this matter.

Station Name	2017 Forecast Min.Inlet (psig)
Parkview & Doris	94
Bayview & Byng	140
Bayview & Sheppard	137
Carpenter & Steeles	158
Faywood & Wilson	137
Sheppard & Kenaston Gdns	137

b) This information is not readily available for the purpose of fulfilling this request within the timelines provided and will not be provided. Further, consistent with the response at a), the inlet pressures of specific stations is of questionable relevance given the need to maintain pressures on each network as a whole.

c) Once the Company's forward-looking analysis indicates pressures below an acceptable level future modelling activity ceases and a solution is considered. As such, Enbridge has not undertaken such a forecasting exercise as it would be of little value. This is because once the forward looking analysis has detected pressures below an acceptable level, it is understood that with future growth, this unacceptable level will only get worse.

STAFF INTERROGATORY # 17

INTERROGATORY

Ref: I.EGDI.SEC.1, Attachment 2, pages 1 and 3

Preamble:
The May 2018 briefing refers on page 1 to an average load growth rate of 158 m^3/h per year and on page 3 to 153 m^3/h (as forecasted at the time the ICF Report was prepared).

Question:
Which number was used as the growth forecast at the time the ICF Report was prepared, 158 or 153?

RESPONSE

The ICF IRP Report was prepared on the basis of 158m^3/h per year.

STAFF INTERROGATORY # 18

INTERROGATORY

Ref: I.EGDI.SEC.1, Attachment 2, page 2

Preamble:
The May 2018 briefing states that "The [Bathurst] reinforcement was submitted as an output of the 2016 LRP and included in the approved capital portfolio for 2018 based on the 2016 LRP numbers."

Questions:
a) When did the Project receive internal approval for inclusion in the 2018 capital portfolio?
b) At the time it was approved, what analysis had Enbridge undertaken of the feasibility of using DSM to defer or reduce the need for the Project?

RESPONSE

Enbridge is concerned that there may be some confusion about the planning process which was followed and the Company's use of its LRP methodology. It should be stated at the outset, that the steps taken leading up to the determination of need, the design of the project, the internal approval process and the use of demand growth forecasts has been the same in respect of the Bathurst Reinforcement as Enbridge has followed in respect of other projects.

As is well known, facility and asset management planning is undertaken using various time horizons. The Company is always looking at longer term forecast needs 10 to 20 years out and at the same time, it is mindful of short term needs as well. Not surprisingly, as the planning horizon lengthens the degree of accuracy and level of detail decrease. Conversely, as the time horizon shortens the specificity and reliability of forecasts and the depth of analysis increases.

In respect of the Bathurst Reinforcement project, Enbridge recognized several years ago that forecast low inlet pressures could in the future cause network pressure concerns in an area of Toronto downstream of the Parkview & Doris Station. As can be seen in the response to Board Staff Interrogatory #16, the 2017 forecast inlet pressure at the station is demonstrably lower than the pressures of other stations identified. The forecast inlet pressure of 94 psig is below the 100 psig threshold which the Company strives to maintain for stations on this network. With inlet pressures forecast below this level, preliminary consideration of a reinforcement project in the area commenced.

The concern associated with low inlet pressure is that it will result in a reduction in the volume of gas which is being moved through the system which puts at risk the Company's ability to meet customer demand downstream. As well, low inlet pressure at an upstream station can have a negative cascading effect on downstream station operations.

As with all reinforcement projects of this nature, the planning and design of the project starts at a higher, less detailed level at first. Stated differently, once need has been identified, a high level solution is developed having a view to relevant factors for the purposes of obtaining internal approvals to proceed further. It is only after internal approvals have been received and internal resources secured that detailed planning and design specification work commences in earnest. This work necessarily involves a more in-depth consideration of routing and location options in addition to the area of influence. It is with this more precise information that more accurate and reliable demand growth forecasts are generated. It is certainly not uncommon for there to be differences, sometimes material, between original estimates generated in the early planning stages and those generated as part of the final detailed project design and specifications work.

In the planning and development of the Bathurst Reinforcement project, Enbridge followed the same logical progression of steps, starting first with the identification of need as it does for the design and planning of all of its reinforcement projects. There is nothing unique about the Bathurst Reinforcement project other than the fact that an earlier iteration of the project was considered by ICF as part of its IRP Report. Again, this original iteration of the project and the growth forecasts generated at that time were based on Enbridge's 2016 LRP which was developed relying largely on long term organic growth forecasts provided by a third party. The 2016 LRP did not consider or incorporate specific development proposals which assist in the refining of forecasts on a short term basis. It should be noted that combining short term development information and long term growth forecasts was and is a technically challenging process. Enbridge had recognized the value of combining this information some time ago, but was only able to accomplish this task recently to inform the 2017/2018 LRP.

After ICF was provided with the original growth forecast, the above noted improvements were made to the 2017/2018 LRP which layered on development proposal data to inform short term system needs. This is in addition to receiving and relying on third party data in respect of longer term customer growth. The changes made to the 2017/2018 LRP are continuing to be used in respect of all project planning. The objective of making the changes to the LRP was to increase the accuracy of forecasts moving forward.

As noted earlier in evidence, the planning process involves far more than an aggregating of all of the current development proposals submitted to a municipality. Such an approach would be inappropriately narrow and short term in scope. While short term information is relevant, it is critical to also consider longer term forecasts. This as noted in evidence and above is accomplished by combining a short term, narrow view of system needs based upon known developments in the area with a long term, geographically specific customer growth forecast generated by the complex methodology of a third party expert. The combination of short term development knowledge, long term growth forecasts, and a greater understanding of the impact of upstream development on low inlet pressures in the area led to the final forecast relied upon by this Application.

While Enbridge relies upon the most recent forecast of peak load growth in the area for the purposes of this Application, Enbridge notes that there are numerous publicly known trends which suggest it should not be surprising that the peak load growth in the area is trending upwards. Recent amendments to the official plan and announcements regarding rapid transit proposals along Steeles Avenue point to an increase in the density of the area. Such changes can have a snowball effect on growth in an area, as densification attracts the interest of developers who themselves bring about further densification in time. Some of this can be seen in the map that was provided as attachment #2 to Exhibit I.EGDI.SEC.1 and which was reproduced in Enbridge's Reply Submission. Please also see Exhibit I.EGDI.SEC.21. Meeting this forecast demand and having a view to the inlet pressure concern identified above, Enbridge has determined that the Bathurst Reinforcement project must necessarily proceed.

a) The Project received internal approval in August 2017.

b) At the time of approval Enbridge had provided inputs relevant to the Project to ICF to inform the IRP Report but it had yet to receive the conclusions of the IRP Report. Given that the need for the Project had been established on a <u>technical</u> basis, the Company was not in a position to delay planning efforts in the hopes that the IRP Report might indicate that DSM could be a cost-effective alternative on a <u>conceptual</u> basis. Please see Exhibit I.EGDI.SEC.28 for further discussion of this subject.

STAFF INTERROGATORY # 19

INTERROGATORY

Ref: I.EGDI.SEC.1, Attachment 2, page 3
Enbridge Reply Submission, page 3

Preamble:
The May 2018 briefing includes a table comparing the growth forecast relied on by ICF and Enbridge's updated growth forecast. The briefing explains that "the area of impact considered in the planning process was expanded", and includes a map showing the expanded area of impact. Enbridge's Reply Submission states that "The growth forecasts which support the Project relate to the area noted (the orange polygon) on this map."

Questions:

a) Please clarify whether the initial growth forecast of 153 m^3/h related only to the smaller area or impact (the red polygon) whereas the revised forecast of 590 m^3/h relates to the expanded area (the orange polygon).
b) Similarly, please clarify whether the initial forecasts for new residential, commercial and apartment attachments, as shown in the middle column of the table, related to the red polygon whereas the updated forecasts, as shown in the right-hand column, relate to the orange polygon.
c) Does Enbridge have recent historical data (e.g. last five years) for load growth in the red polygon and the orange polygon? If so, please provide it.

RESPONSE

a) For clarity, as indicated on the map provided in the response to SEC Interrogatory #1 found at Exhibit I.EGDI.SEC.1 Attachment 2, page 3, a larger version of which was reproduced as an attachment to Enbridge's Reply Submission, the red polygon refers to the high pressure mains upstream of the Project, along which growth is forecast to contribute to low inlet pressures. The orange polygon located at the same reference represents the area of intermediate pressure networks which will benefit from, or have contributed to the need for, the Project. Neither the red, nor orange polygons on this map represent the previous, smaller area of impact used as the basis for information provided to inform the IRP Report. Both polygons together represent the area which has necessitated and will benefit from the Project.

b) Please see a) above.

c) Please see the response to SEC Interrogatory#3 found at Exhibit I.EGDI.SEC.3 for Net Annual Customer Attachments and Average Annual Consumption by customer type for the area relevant to the Project.

STAFF INTERROGATORY # 20

INTERROGATORY

Ref: I.EGDI.STAFF.9
I.EGDI.SEC.1, Attachment 2
I.EGDI.SEC.5

Preamble:
In response to OEB staff interrogatories, Enbridge indicated that it considered geo-targeted DSM as an alternative to the construction of the Bathurst Reinforcement Project. However, geo-targeted DSM was determined to not be viable.
In the ICF IRP Executive Summary filed in response to SEC interrogatories, ICF concluded that "it may be more cost-effective to launch [a] geo-targeted DSM program than to install the reinforcement project".
Enbridge says that the growth information provided to ICF was originally the best available information at the time. Subsequent to the 2016 Natural Gas Conservation Potential Study prepared by ICF, Enbridge obtained updated information.

Questions:
a) Please describe the types of geo-targeted DSM offerings that were considered for use on the Project at the time of the ICF report and explain how these differ from Enbridge's current suite of DSM offerings. In the response, please comment on:
   - Where efficiencies or gas savings may have been realized?
   - Whether financial incentives or new pricing schemes may have been required?
b) In the months between the time when ICF identified geo-targeted DSM as potentially being cost-effective (in or around January 2018) and the time Enbridge revised its growth forecast (in or around May 2018) did Enbridge explore any specific geo-targeted DSM programs for the Project area? If so, which ones?
c) Did Enbridge engage ICF or any other expert consultant after the updated growth information became available in order to reassess the suitability of DSM with respect to the Project? Please explain.
d) Please indicate if scenarios were considered by Enbridge or ICF in which geo-targeted DSM could be used to redesign the Project (e.g. use a shorter or smaller diameter pipeline) or defer the Project for some period of time (e.g. one or two years).

RESPONSE

a) ICF leveraged the results of the 2016 OEB Conservation Potential Study for the purposes of its report. The measures identified in the potential study were considered in the analysis for the IRP Study and the Bathurst St case study, with the exception of adaptive thermostats as this technology is shown to increase peak hour demand. ICF estimated that the cost of implementing geo-targeted DSM programs would be in the range of 1.5 to 2 times more expensive than implementing broad based DSM programs.

b) Given Enbridge's high level analysis showing that geo-targeted DSM could not reduce the peak demand sufficiently to defer the project, further micro analysis was not deemed a prudent expenditure of resources and was therefore not undertaken.

c) Prior to receiving Procedural Order No. 2 issued on November 12, 2018, neither ICF nor any other consultant was asked to reassess the DSM conclusions made regarding the Bathurst Reinforcement. However in an effort to be responsive and address any uncertainty that may exist, on November 20, 2018 Enbridge requested that ICF review the DSM conclusions utilizing the updated load and budget costs for the Bathurst LTC project. The results of ICF's further analysis can be found in the attached memo. As can be seen, ICF's review of the project using updated load and budget costs resulted in ICF concluding that DSM could not cost effectively offset or defer the project.

d) Please see response to b and c) above.

MEMORANDUM

To: Fiona Oliver-Glasford, Suzette Mills, Enbridge Gas Distribution

From: Mike Sloan, John Dikeos, and Dan Bowie, ICF

Date: November 22, 2018

Re: Updated Results: Bathurst LTC Project Case Study

Background:

On November 20, 2018, Enbridge Gas Distribution Inc. (EGD) requested that ICF provide updated exhibits pertaining to "Case Study #1" in ICF's IRP Report.[1] Although not explicitly indicated in the report, this case study referred to the Bathurst LTC project. The following updated inputs for the Bathurst LTC project from the 2017/18 Long Range Plan shown in the table below were provided to ICF for this case study. The original inputs to the analysis for Case Study #1 (i.e. Bathurst (IRP Case Study)) are shown for comparison purposes:

Metric		Bathurst (IRP Case Study)	Bathurst (LTC Application)
Estimated Facility Investment Cost ($)		$8,200,000	$9,147,651
Baseline Peak Hour Demand (m^3/h)	Residential	14,487	44,439
	Commercial	15,855	60,416
	Apartments	*5,438*	*32,921*
	Other Commercial	*10,147*	*27,495*
	Industrial	0	4,367
	TOTAL	**30,342**	**109,222**
Average Annual Peak Hour Demand Growth	(m^3/h)	158	590
	(%)	0.50%	0.52%

ICF used these revised inputs to re-run the Case Study #1 analysis for the Bathurst LTC project. It should be noted that this analysis represents a hypothetical situation in which the refined

[1] ICF, "Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment – Final Report", completed on behalf of Enbridge Gas Distribution and Union Gas Limited, pp. 154-155, May 18, 2018.

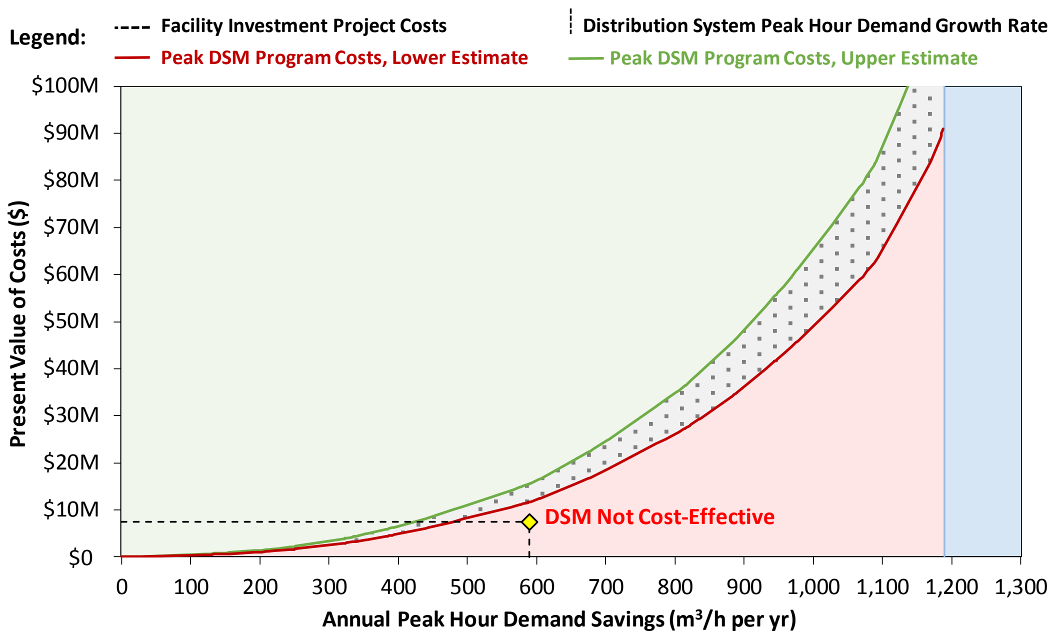
inputs could have been leveraged to evaluate the feasibility and cost-effectiveness of a potential geo-targeted DSM program.[2] ICF did not make any changes to the timeline for project implementation, and DSM implementation and evaluation. Hence the revised analysis is directly comparable to the analysis in the IRP study, and the change in results reflects the change in the size and cost of the project, rather than a change in project timing.

The text and accompanying exhibits from the IRP Report have been updated below, with updates to text indicated in red.

Updated Results:

Exhibit 1 presents the geo-targeted DSM supply curve for a distribution system located in Enbridge's Central region, where 55% of the peak hour demand is attributed to commercial customers, 41% to residential customers, and the remaining 4% to industrial customers. The current peak hour demand from the distribution system is approximately 109,000 m³/h and is growing at an average rate of 590 m³/h per year (or 0.52%). Based on information provided by Enbridge, the peak hour demand growth will need to be accommodated by a facility investment project that is anticipated to have a capital cost of $9,147,651 for the installation of 3.2 km of an NPS 12 steel high-pressure pipeline.

Exhibit 1: Comparing Facility Investment with Geo-Targeted DSM in Enbridge's Central Region (Case Study #1)



For this case study, geo-targeted DSM does not appear to be cost-effective. This result is shown in Exhibit 2, where it can be seen that the PV of the planned facility investment project is approximately $7.5M, while it is estimated that a geo-targeted DSM program can provide the necessary annual peak hour demand savings of 590 m³/h for a PV cost ranging somewhere between $11.7M and $15.6M.[3]

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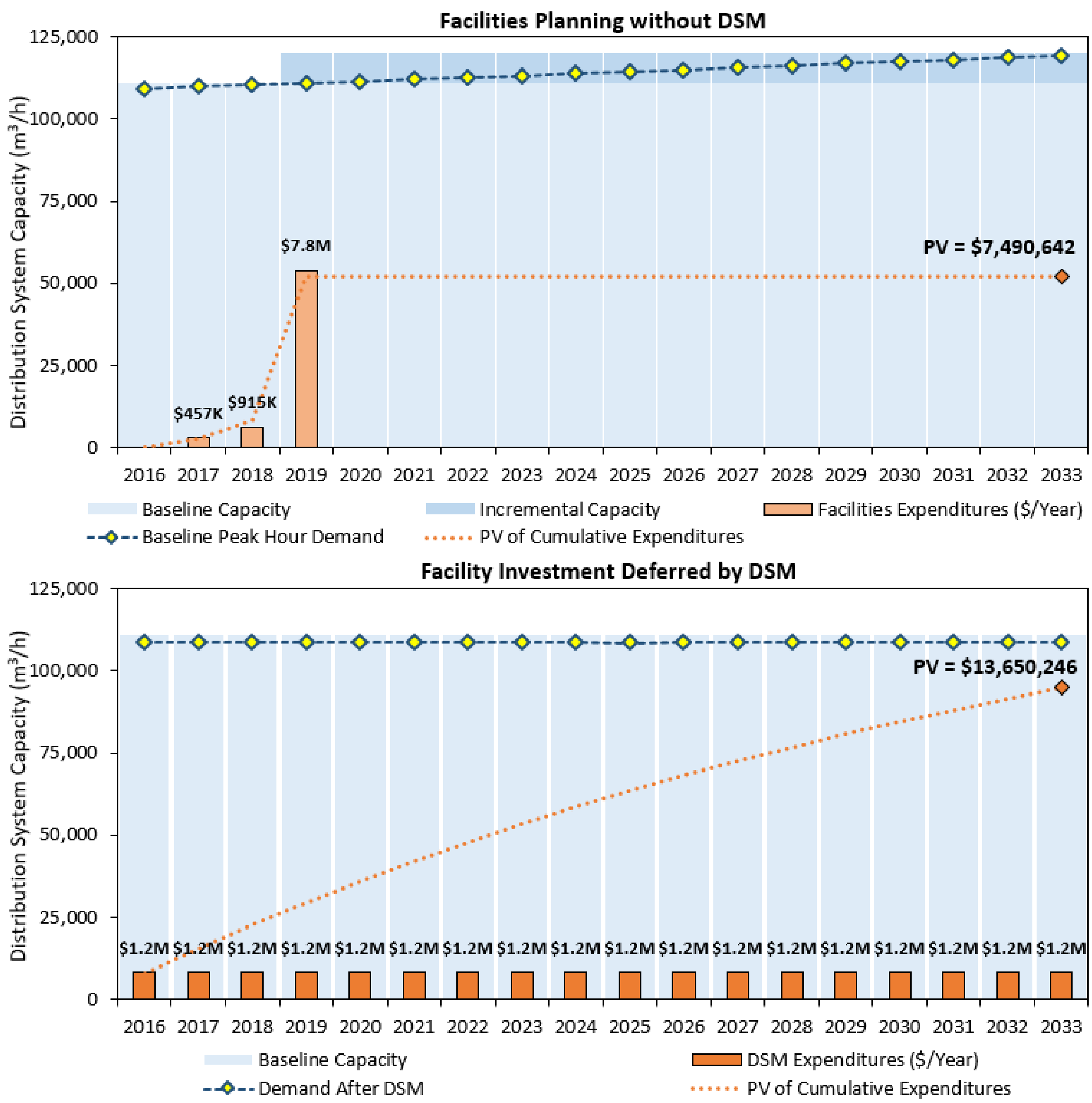
[2] Due to the current risks and uncertainty associated with DSM-driven facilities deferral, as discussed in the IRP Report, a minimum 3-year planning horizon is recommended when evaluating the potential of DSM-driven infrastructure deferral. This would allow EGD to begin implementing and monitoring the impacts of a geo-targeted DSM program well in advance of the anticipated in-service date of the otherwise needed facilities investment.

[3] *This range of geo-targeted DSM program costs corresponds to the points on the green line and the red line along the vertical dotted line corresponding to 590 m³/h.*

The cash flows for each scenario are displayed in Exhibit 2, where it can be seen that annual expenditures of $1.2M on geo-targeted DSM until 2033 would result in a total PV cost of $13.65M while maintaining the peak hour demand below the capacity of the existing distribution pipeline.

Exhibit 2: Comparison of Facility Planning Cash Flows with and without Geo-Targeted DSM (Case Study #1)



SEC INTERROGATORY # 12

INTERROGATORY

Ref: SEC.1, Attach 2, p. 3, version attached to Reply Submissions

Question:
With respect to the map of the area served:

a. Please divide the increased demand of 4,370 m3/h over the ten year planning period between the high pressure area along Steeles, Bayview and Parkview, and the intermediate pressure area in the rest of the polygon.
b. For each of the main load increases assumed between the first estimate and the second estimate of load, please
   i. identify where on the map the additional load is expected, and when if that is known, and
   ii. explain why the load was not included in the original forecast.

RESPONSE

a) In the 2017 LRP demand is split roughly 11% / 89% between HP and IP networks respectively. Due to the differences in methodology between the 2016 and 2017/18 LRP's it not possible to conclusively determine a direct comparable divide for the 4,370 m^3/h figure cited above.

b) Please see the map located in the response to SEC Interrogatory #1 found at Exhibit I.EGDI.SEC.1, Attachment 2, page 3 as reproduced in a larger format in Enbridge's Reply Submission.

   i. On this map, each of the small pink coloured polygons are proposed developments that are received by Enbridge from, in this case, the City of Toronto. If the polygon lies beside an orange coloured pipe, the polygon is fed by an IP network. If the polygon lies beside a blue coloured pipe, the polygon is likely fed by the adjacent HP network. Each polygon has its own timing for load addition based on scope and chronology of the project derived from information provided by the project proponent.

   ii. Please see the response to OEB Staff Interrogatory # 18 found at Exhibit I.EGDI.Staff.18.

SEC INTERROGATORY # 13

INTERROGATORY

Ref: SEC.1. Attach 1, p. 5 of 49

Question:
Please explain why the SAG did not including any representatives of environmental or customer groups, despite the Applicant's knowledge that those groups had a direct interest in geo-targeted DSM, and had experts knowledgeable in the subject.

RESPONSE

Enbridge, with input from ICF, planned to convene a Stakeholder Advisory Group drawn from a wide cross section of North American gas utilities, planners, DSM / CDM professionals and academic communities.

It was anticipated that this external review would bring a fresh, broad and objective perspective to this study and to help ensure the quality of the study across the several specialized fields involved. Individuals identified for the SAG were those who could offer new perspectives and industry experience helpful to move the dialogue forward in a constructive manner recognizing there are no experts in planning for or implementing natural gas IRP. Beyond the SAG, the Company notes that there have been and will be opportunities to discuss the material and receive intervenors' perspectives through DSM regulatory proceedings or other processes. The Stakeholder Advisory Group was struck with best practices in mind and to gain market and industry input into a nascent practice area given, as confirmed by ICF in its study, the very limited information available on targeted natural gas DSM to defer infrastructure.

Enbridge further notes that ICF determined that electricity industry IRP experience is of only limited value as an example to natural gas IRP.

> ICF's review of existing DSM programs at North American gas utilities in other jurisdictions found that little to no activity has been undertaken to directly reduce transmission and distribution costs using targeted DSM and Demand Response (DR). In addition, ICF found that the measured data on hourly natural gas consumption necessary to determine the potential impacts of DSM on new facilities requirements is generally unavailable.
>
> ICF also assessed activity in the electric power industry. However, differences in utility cost structure, duration of peak period requirements, and availability of data on DSM impacts lead ICF to the conclusion that geo-targeted DSM programs are likely to be more cost-effective for the electric industry than they are for the natural gas industry, and that

the electric industry experience provides only relatively limited value as an example for the gas industry.[1]

[1] Filed: 2018-01-15 EB-2017-0128 Enbridge Submission Appendix D Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment. Pg 6 of 49

SEC INTERROGATORY # 14

INTERROGATORY

Ref: SEC.1. Attach 1, p. 14 of 49

Question:
Please describe all steps taken by the Applicant to date to determine the impact of DSM programs (whether geo-targeted or otherwise) on peak day or peak hour demand.

RESPONSE

Enbridge completed the IRP Study and is field testing the conclusions to better inform the transition to IRP.

SEC INTERROGATORY # 15

INTERROGATORY

Ref: SEC.1. Attach 1, p. 33 of 49

Question:
Please provide all information provided to ICF on the load to be displaced by DSM in the Bathurst Reinforcement area, including all information on the size, sources, timing, and locations of load that needed to be displaced.

RESPONSE

Enbridge provided ICF the number of apartment, commercial, industrial and residential customers in the area of influence, the forecasted peak demand in the area of influence due to those customers, and the aggregate average yearly incremental demand based on forecasted customer additions over the next 10 years. Enbridge also provided the scope, information around the reason for the project, year required, and total estimated cost of the reinforcement at that time. Please see the response to OEB Staff Interrogatory #20 found at Exhibit I.EGDI.STAFF.20 Attachment 1, page 1 for the above noted values.

SEC INTERROGATORY # 16

INTERROGATORY

Ref: SEC.1. Attach 1, p. 33 of 49

Question:
Please provide all information provided to ICF relating to existing DSM programs in the Bathurst Reinforcement area, and the potential for additional DSM activities in that area.

RESPONSE

Enbridge did not provide further information to ICF related to existing DSM programs.

During 2016, ICF completed an OEB CPS study that focused on estimating the achievable potential for natural gas efficiency in Ontario from 2015 to 2030. The study was completed on behalf of the OEB and in consultation stakeholders including the Gas Utilities.

It was this base year (2014) from the OEB CPS that formed the starting point for the IRP Report analysis regarding the potential of DSM to defer infrastructure.

SEC INTERROGATORY # 17

INTERROGATORY

Ref: SEC.1, Attach 2, p. 2

Question:
Please provide the numerical data behind the two graphs on this page. If there is any data in the possession of the Applicant or ICF relating to the cost-effectiveness of the planned DSM aside from its comparison with the cost of the new facilities (for example, using the TRC Plus test), please provide that data as well.

RESPONSE

All of the data points supporting the above noted graphs can be found on the graphs themselves and on page 154 of the full IRP Report as filed at OEB Staff Interrogatory #13 found at Exhibit I.EGDI.STAFF.13 Attachment 1 under the heading "Case Study 1: Geo-Targeted DSM Costs Less than Planned Facility Investments". The way in which cost-effectiveness was analyzed and incorporated into the IRP Report is thoroughly described in the report's methodological explanations. The Company notes that the Board's Conservation Potential Study was leveraged by ICF in their preparation of the IRP Report.

SEC INTERROGATORY # 18

INTERROGATORY

Ref: SEC.1, Attach 2, p. 2

Question:
Please provide similar graphs using the new capital cost, load forecast, and timing, and inserting the expected DSM budget required to displace the new load growth expected. Please provide the numerical data behind those graphs as well. If this analysis has not been done, please explain why. If any analysis has been done, please advise what types of cost-effectiveness analysis have been included.

RESPONSE

Please see the response to OEB Staff Interrogatory # 20 found at Exhibit I.EGDI.STAFF.20 Attachment 1.

SEC INTERROGATORY # 19

INTERROGATORY

Ref: SEC.1, Attach 2, p. 2

Question:
Please provide full copies of the 2016 and 2017/18 Long Range Plans of Enbridge, and provide (if the information is not already contained within the documents) the material changes in methodology between the two plans, and the impacts of those changes.

RESPONSE

Please see the response to OEB Staff Interrogatories #15 and #18 found at Exhibit I.EGDI.STAFF.15 and Exhibit I.EGDI.STAFF.18 respectively for a description of the methodological changes between the 2016 and 2017/2018 Long Range Plans. The Company believes SEC's request to provide both plans in their entirety is outside of the narrow scope provided for in Procedural Order No. 2 issued by the Board in this proceeding.

SEC INTERROGATORY # 20

INTERROGATORY

Ref: SEC.1, Attach 2, p. 2

Question:
Please provide all additional information in the possession of the Applicant that supports the 386% increase in load from the first load forecast to the second, or would otherwise assist the Board in understanding the reasons for that increase.

RESPONSE

Please see the responses to SEC Interrogatory # 1 and OEB Staff Interrogatory # 18 found at Exhibit I.EGDI.SEC.1 Attachment 2, and Exhibit I.EGDI.STAFF.18, as well as paragraphs 11 and 13 of Enbridge's Reply Submission. As noted at these references the refinement of LRP methodologies and expansion of the area which necessitated and benefits from the Project are together responsible for the final forecast submitted in this Application.

SEC INTERROGATORY # 21

INTERROGATORY

Ref: SEC.1, Attach 2, p. 3, SEC.7

Question:
With respect to the commercial and apartment load growth in each of the old forecast and the new forecast:

a. Please identify on the map where the "additional data points" would be developed;
b. If the additional data points cannot be located on the map, please reconcile the built-up area served by the project with the high load growth forecast, and show that there is developable land in the area to accommodate the forecast attachments, and
c. Please provide a table, in the same format as SEC.3, showing the annual attachments expected by year in the forecast over the period 2020-2029.

RESPONSE

a) Please see the response to SEC Interrogatory # 12 found at Exhibit I.EGDI.SEC.12 b).

b) Not applicable; please see part a).

c) Please see Exhibit B, Tab 1, Schedule 1, page 1, table 1 of Enbridge's pre-filed evidence.

SEC INTERROGATORY # 22

INTERROGATORY

Ref: SEC.1. Attach 2, p. 3

Question:
Please confirm that the area served by this project does not include residential or other development in the Downsview Park development plan. If it does include any part of that development area, please provide details.

RESPONSE

Confirmed.

SEC INTERROGATORY # 23

INTERROGATORY

Ref: SEC.1. Attach 2, p. 4

Question:
Please explain why ICF was not asked to review their DSM conclusions relative to the Bathurst Reinforcement in light of the new information in the hands of the Applicant as to load and cost. Please provide copies of all communications between the Applicant and ICF related to the new information and its impact on their conclusion.

RESPONSE

Please see the response to OEB Staff Interrogatory #20 found at Exhibit I.EGDI.STAFF.20 Attachment 1 for a revised analysis completed by ICF using updated information relative to the Project. Please find as Attachment 1 to this interrogatory response an email communicating revised information regarding the Project to ICF.

From: Jeffrey Mazzei
Sent: Friday, November 23, 2018 2:24 PM
To: Fiona Oliver-Glasford
Subject: Fwd: Revised Bathurst LTC information

Begin forwarded message:

From: Jeffrey Mazzei <Jeffrey.Mazzei@enbridge.com>
Date: November 20, 2018 at 3:22:20 PM EST
To: "Dikeos, John (John.Dikeos@icf.com)" <John.Dikeos@icf.com>, "Sloan, Michael (Michael.Sloan@icf.com)" <Michael.Sloan@icf.com>
Cc: Suzette Mills <Suzette.Mills@enbridge.com>, Kent Todd <Kent.Todd@enbridge.com>, Neerajah Raviraj <neerajah.raviraj@enbridge.com>, Fiona Oliver-Glasford <Fiona.OliverGlasford@enbridge.com>, Cody Wood <Cody.Wood@enbridge.com>
Subject: Revised Bathurst LTC information

John and Mike,

Please see below for the numbers that apply to the new control volume for the Bathurst LTC.

Let me know if you have any questions. Thank you for your help.

	Ave m3/h/cust*	cust count**	m3/h
Apartment	123.3	267	32,921
Commercial	14.1	1950	27,495
Industrial	397	11	4,367
Residential	1.3	34184	44,439

total m3/h***	109,222	m3/h

LTC growth (over 10 yrs)****	590	m3/h/y

*=average peak demand at design day for that demand group as of 2018 CMM
**=count of customers in that demand group in affected area as of 2018 CMM
***=total peak hr demand in new control volume
****=10 year flow increase/10 = yearly demand growth in affected area

Jeff Mazzei, LL.M., P.Eng., CMVP
Long Range Planning Specialist
—

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SEC INTERROGATORY # 24

INTERROGATORY

Ref: SEC.1. Attach 2, p. 4, Reply submissions, para. 29

Question:
Please provide all analyses, studies, or other work done to support the conclusion that the "project [is] likely not possible to be affected by DSM".

RESPONSE

Please see the response to SEC Interrogatory # 1, found at Exhibit I.EGDI.SEC.1 Attachments 1 and 2, as well as the discussion of this throughout Enbridge's Reply Submission. Taken together, the above noted evidence, as emphasized in paragraphs 29 and 30 of Enbridge's Reply Submission, clearly demonstrate that the Project could not cost-effectively be deferred or delayed by way of geo-targeted DSM.

SEC INTERROGATORY # 25

INTERROGATORY

Ref: SEC.6, SEC.8

Question:
Please provide a copy of any order, formal determination, letter, or other communication from the City of Toronto restricting the Applicant's ability to carry out the Bathurst Reinforcement Project to within the period April 2019 to December 2019, or prohibiting the work on the project after December 2019.

RESPONSE

Please find attached to this interrogatory response an email communication from the City of Toronto regarding timing restrictions for completion of the Project due to other utility works. The email communication provided is supplementary to verbal communications between Enbridge and the City of Toronto in which Enbridge was informed that after utility works scheduled for the spring of 2020 were completed a multi-year moratorium on further work along Bathurst Street would be put in place.

From: Doodnauth Sharma [mailto:Doodnauth.Sharma@toronto.ca]
Sent: Wednesday, February 21, 2018 8:33 AM
To: Tracy Witney
Cc: Jaclyn Mui
Subject: [External] Re: Bathurst Reinforcement

Hi Tracy,

As previously mentioned, there is watermain work on Dufferin that will start in 2018 and finish in 2019, Enbridge work cannot start on Bathurst until all the lane restrictions on Dufferin are removed. At the moment Dufferin is scheduled to be completed in June 2019 but if the major underground works are completed earlier then Enbridge can start earlier. You will need to coordinate in year with the project leader, see T.O. INview. Enbridge currently has a June 2019 to December 2019 window to complete its work. In year coordination will be required if you will need to start earlier and finish later than 2019. If the watermain project will happen during the winter 2019, then they may finish earlier. Also, if no project is being done in the winter of 2020, Enbridge will be allowed to work in the winter to finish up its work. At the moment, Yonge Street will be under construction so it will be preferred if Enbridge can finish its major lane restriction works on Bathurst in 2019.

Thank you.
Doodnauth Sharma, M.Eng., P.Eng., PMP
Senior Project Manager, Major Capital Infrastructure Coordination Office
100 Queen Street West, 4th Floor, East Tower, City Hall
Toronto, ON M5H 2N2
Office: 416 397 0784
Fax: 416 397 4007
E: doodnauth.sharma@toronto.ca
https://map.toronto.ca/toinview/

SEC INTERROGATORY # 26

INTERROGATORY

Ref: SEC.11

Question:
Please confirm that the Applicant has not developed any scenarios to test how much it would cost to displace this project with geo-targeted DSM, nor what types of DSM programs would be required to achieve that result.

RESPONSE

Please see the response to OEB Staff Interrogatory # 20 found at Exhibit I.EGDI.STAFF.20 Attachment 1.

SEC INTERROGATORY # 27

INTERROGATORY

Ref: Reply submissions, para. 14

Question:
With respect to the issue of "low inlet pressures, please provide:

a. Details of the inlet pressures for "this network" assumed in the information provided to ICF, and today;
b. Details of the additional investigations or information that caused the change in inlet pressures assumptions;
c. A table comparing inlet pressures for this network with the inlet pressures for each similar network in the City of Toronto;
d. Confirmation that, when the initial analysis was done and provided to ICF, the statement "if the primary source feeding this network were to fail during the heating season, there is a risk of losing approximately 3100 existing commercial and residential customers" was not true at that time. If confirmed, please explain how that is possible;
e. Confirmation that adding a redundant source to any network will, generally speaking, increase reliability. Please explain how this addition of redundancy is different from others.

RESPONSE

a) ICF was not provided network details such as low inlet pressures at any time. Please see the response to OEB Staff Interrogatory #16 found at Exhibit I.EGDI.STAFF.16.

b) Inlet pressure assumptions have not changed throughout the course of project development.

c) Please see OEB Staff Interrogatory #16 found at Exhibit I.EGDI.STAFF.16. Beyond this response, Enbridge is of the view that this request is outside the scope of the 2 issues raised by the Board in Procedural Order No. 2. In addition, it is unclear what constitutes a similar network for the purposes of this response given that areas in the City have developed and are served by facilities that have been constructed in response to historic unique growth patterns that are not directly comparable and which now face different future growth forecasts. These realities make any attempted comparison of little value.

d) Not confirmed. As noted in the response to SEC Interrogatory #1 found at Exhibit I.EGDI.SEC.1 Attachment 2, page 4, “System flexibility needs are also a driver for the project, but [were] not included or valued in the ICF analysis which was strictly on a $ per m3/h of incremental capacity basis…”

e) Confirmed. Consistent with Enbridge’s past and present approach to the safe and reliable operation of its distribution system, the Company finds additional redundancy warranted given that “…the primary source feeding this network is having low inlet pressures”, as noted on page 1 of Exhibit B, Tab 1, Schedule 1.

SEC INTERROGATORY # 28

INTERROGATORY

Ref: Reply submissions, para. 30-36

Question:
Please confirm that, as a result of the outstanding policy issues yet to be addressed by the Board, the Applicant believes that it would not be appropriate for the Applicant to use geo-targeted DSM to defer or displace facilities projects at this time.

RESPONSE

Natural gas Integrated Resource Planning (IRP) involves many complicated processes and barriers. Enbridge is committed to continuing to take steps to study and evolve natural gas IRP. ICF's conclusions from the IRP Report find that "Integrating the potential for DSM to reduce infrastructure requirements into the facilities planning process will require significant changes in policy, as well as changes in the utility planning process."[1]

Although in the case of the Bathurst LTC it is evident from the high level analysis, and further confirmed by ICF in the response to OEB Staff Interrogatory #20 found at Exhibit I.EGDI.STAFF.20 Attachment 1, that geo-targeted DSM was not a viable solution, it is possible there could be other opportunities relating to future LTC projects. As a practical matter, Enbridge is looking to the Board for direction regarding the barriers and policy issues identified in the IRP Report prior to conducting more detailed analytical work which is anticipated to be resource intensive. This evolutionary approach to IRP is consistent with the final recommendations of ICF.

The Company wishes to highlight the significant gap remaining between the conceptual possibility of deferring or avoiding infrastructure investments through DSM, as explored thoroughly in the IRP Report, and technically implementing such alternatives in a prudent and cost-effective manner. Even had DSM conceptually proven to be a cost-effective alternative to the Project, which it has not, the Company would need to: (1) undertake a geographically specific conservation potential study; (2) based on this study, design DSM programs specific to the area in question; (3) apply to the Board to

[1] Filed: 2018-01-15 EB-2017-0128 Enbridge Submission Appendix D, Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment Page 46 of 49

receive approval for the necessary funding over and above currently approved DSM budgets; (4) successfully market the geo-tailored programs to customers; (5) monitor and oversee the implementation of energy efficiency measures; and, (6) conduct a robust evaluation and measurement program for a significant enough period of time to confirm the sufficiency of savings achieved and their impact on peak load. It is for this reason that ICF notes in the IRP Report that DSM must start implementation (not planning) 3 years ahead of the expected date for a facility investment project.[2] In Enbridge's view, even 3 years may be an underestimate of the time required to successfully roll out geo-targeted programs and have the necessary number of efficiency measures in place to achieve a material impact.

The status of natural gas IRP in Ontario, indeed in North America, is perhaps best stated by Enbridge's independent expert in their IRP Report:

> The use of DSM to reduce investments in natural gas facilities remains relative untried and untested. While ICF has identified areas where there is potential to use DSM to avoid infrastructure investments, there remains significant uncertainty in both the potential and the cost of achieving that potential. There is little to no actual measured data on DSM program impacts on peak period demand for natural gas, and there are no significant real world examples that ICF can point at to indicate that DSM can be used effectively for this purpose.
>
> As a result, there is currently a fundamental disconnect between the limited risk acceptable to the Utilities in the facilities planning process and the lack of information on the ability of DSM to reliability reduce peak period demand that will need to be addressed before the Utilities would be able to rely on DSM to reduce infrastructure investment…[3]

In order to bridge the gap between the conceptual and the technically practical, the Company recommends the initiation of a standalone consultation regarding IRP.

[2] Exhibit I.EGDI.SEC.1, Attachment 1, page 33
[3] Exhibit I.EGDI.SEC.1, Attachment 1, page 47