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January 15, 2018

VIA COURIER AND RESS

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, Ontario
M4P 1E4

Dear Ms. Walli:

Re: Ontario Energy Board
EB-2017-0127 / EB-2017-0128 – DSM Mid-Term Review
Submission of Enbridge Gas Distribution Inc.

In accordance with the Ontario Energy Board's letter issued on June 20, 2017, enclosed please find the submission of Enbridge Gas Distribution Inc.

Please contact the undersigned if you have any questions.

Sincerely,

(Original Signed)

Bonnie Jean Adams
Regulatory Coordinator

Attach.

DEMAND SIDE MANAGEMENT MID-TERM REVIEW

EB-2017-0127/0128

SUBMISSION FROM ENBRIDGE GAS DISTRIBUTION INC.

January 15, 2018

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Introduction

1. In its letter issued on June 20th, 2017 the Ontario Energy Board (OEB) set out the scope for the Mid-Term Review of the 2015-2020 Demand Side Management (DSM) Framework. The scope separated the Mid-Term Review into two parts. The first part was a limited review of the overall Framework with respect to Cap and Trade (C&T) programs, which Enbridge Gas Distribution Inc. (Enbridge) filed its comments on September 1st, 2017. The second part had two requirements; the first was to submit studies and reports on specific topics, which Enbridge filled on October 1st, 2017. The second requirement was to submit studies, reports and comments on various topics on January 15th, 2018, which form the basis of this submission.

2. This submission is organized into parts that align with the requests from the Board that are applicable to Enbridge. In addition Enbridge has included an update on two specific programs, the Home Energy Conservation Program and the Savings By Design Programs, as well as a general update on the Company's efforts to collaborate.

3. Throughout the submission, Enbridge has proposed several enhancements for the Board's consideration. A summary of these are included in Section 11, Table 7 for ease of reference.

Section 1: Adaptive Thermostats Integration with Electric Utilities

4. In the Multi-Year Plan (2015-2020), Enbridge proposed an adaptive thermostats program that provided a rebate of $75 towards the purchase of one eligible thermostat per customer. Adaptive thermostats respond to a customer's behaviour and can be controlled remotely through a customer's smart device. The Company built a very cost-effective budget of $876,371 for the program year 2016 to cover

the costs of customer incentives, marketing and other program administration costs.

5. In the Decision, the Board applied a 10% increase to all targets effective 2016. This compromised the Company's ability to reach its targets as the customer incentive budget did not proportionality increase by 10%. In order to reach its targets the Company would have to use the funds intended for marketing in order to pay the customer incentives required to reach target achievement. Considering the program was new to the market and the technology was not yet widely adopted, marketing was expected to be a crucial component of the program's success.

6. To generate cost-efficiencies and free funds to enhance the customer incentive as a means to move the market, the Company sought a collaborative agreement with Toronto Hydro to deliver an adaptive thermostats program to shared customers. This agreement would also satisfy the Board's direction to explore "an integrated program with electricity utilities related to adaptive thermostats[1]." Adaptive thermostats control a home's heating temperature in the winter and for many homes central air conditioning in the summer which creates an opportunity for both gas and electric savings. The dual-fuel savings created by adaptive thermostats made for an ideal technology to explore within an integrated CDM and DSM program offering.

7. There are approximately 450,000 single family households in the City of Toronto that have both natural gas heating and electric central air-cooling who are eligible for the adaptive thermostats incentive. By collaborating to incent these customers, both utilities would realize cost savings by avoiding duplication of administrative

[1] DSM Mid-Term Review (EB-2017-0127 and EB-2017-0128), Ontario Energy Board, June 20,2017

work, rebate module purchases, tracking and fulfillment work, marketing and promotional efforts, and customer service functions.

8. Toronto Hydro received approval from the IESO for collaboration funding on March 11th, 2016 and Enbridge and Toronto Hydro entered into an Integrated Program Delivery Agreement (IPDA) with a launch date set for October 2016. The IPDA was intended to become the Companies standard agreement for collaborative delivery with other electric utilities going forward.

9. Enbridge delivered its adaptive thermostat program by offering an enhanced $100 on-bill rebate to participating customers across Enbridge franchise area. For participating customers that have central cooling, Toronto Hydro contributed a $50 incentive towards their $100 rebate, thereby offsetting $50 per participant for Enbridge.

10. Through this agreement, Enbridge covered the costs of the rebate modules and provided on-bill rebate service for Toronto Hydro including management of the back-end portal tool used to track, invoicing and incentive payments. By Enbridge providing the on-bill credit service, customers benefited from having a single point of contact for this incentive. Enbridge then invoiced Toronto Hydro bi-monthly for each unit incented by the utilities.

11. Enbridge used the manufacturer portal to collect all customer application information and used it for tracking, invoicing Toronto Hydro, and fulfillment of on-bill credit through a Stakeholder Relationship Management (SRM) systems that provides customer relationship management capabilities for DSM programs. Information was applied by tracking and reporting through Data Analysis Reporting and Tracking Systems (DARTS) in order to capture the total gas and electric savings.

12. The partnership with Toronto Hydro created a streamlined approach with a focus on a simplified and positive customer experience. The participant would simply purchase and install the adaptive thermostat, set up their account with the manufacturer and apply for the rebate online. Due to Enbridge's existing infrastructure this program was easy for Toronto Hydro to "piggy-back" onto and created a template for other electric LDC's to follow suit.

13. This collaborative delivery model proved to be the least disruptive in the marketplace by avoiding customer confusion on who was providing the rebate, and the rebate amount itself. Currently nine (9) devices are eligible to participate in the collaboration agreement as Toronto Hydro has approved all but one manufacturer as an eligible model. All new models that are added to the Enbridge program are sent to Toronto Hydro well in advance to approve the device as an additional eligible model.

14. Enbridge and Toronto Hydro also collaborated on deploying marketing materials to promote the Adaptive Thermostats program, including brochure inserts, landing pages, 'take-ones' and direct mail. By leveraging the trust customers have in the Enbridge and SaveONenergy brands, the joint marketing efforts saw an increase in website source traffic, thus demonstrating a higher awareness and participation in the program.

15. The enhanced $100 incentive for the City of Toronto which launched in October of 2016 provided the utilities with only two (2) months in the year to incent participants. Due to the small window of time to promote the enhanced incentive, only 2,026 units were incented for 2016 out of a target of 5,000.

16. For 2017, final results have yet to be counted, however as of late November 2017, 4,860 units were incented for 2017, meaning the utilities are well on track of reaching and exceeding the target of 5,000 units. To ensure momentum continues, Toronto Hydro was granted permission from the IESO to accept more than 5,000 units for the remainder of 2017, thus allowing the utilities to exceed target and drive more results.

17. For the 2018 program year Enbridge and Toronto Hydro are currently in negotiations to extend the terms of the IPDA. Originally when the IPDA was signed between Enbridge and Toronto Hydro, the Company intended to use the agreement as a template that would serve further collaborative efforts between Enbridge and electric utilities within the Enbridge franchise area to drive results across the province. The IPDA had a clear attribution policy whereby Enbridge claims gas savings, and Toronto Hydro claimed electric savings. Within the IPDA, Enbridge leveraged its existing infrastructure to process the customer rebate, providing a single point of contact and less confusion for the customer, while benefiting from the combined strength of the Enbridge and Save ON Energy brands.

18. However, on December 13, 2017 the GreenON launched another Smart Thermostats Rebate program. This program is very similar to the Enbridge Adaptive Thermostats program and created a source of confusion in the marketplace about who is offering the rebate and uncertainty about the differences between the two offers.

19. The GreenON program exactly mirrors Enbridge's offering with three exceptions. First, the GreenON program is province-wide and extends to Ontarians outside of Enbridge's franchise area. Second, the offer provides a $100 cheque rather than an on-bill rebate, which may be more attractive to customers that are looking for

cash versus an on-bill rebate. Third, only select versions of the Nest and Ecobee models (approximately 5) are eligible through the GreenON program whereas the Enbridge program currently offers 12 models. To the benefit of ratepayers, Enbridge's list of eligible models continues to grow as manufactures add more models at various price points to the market and Enbridge maintains the infrastructure to support it.

20. The customer experience has changed with the introduction of the GreenON offer in the marketplace. Multiple rebate offerings in the market have created confusion for customers and do necessarily offer a competitive "choice" to the benefit of the consumer. Rather, the Company believes that since the two programs in market are very similar, a good use of funds would be to coordinate the offers by collaborating and offering a richer incentive using one utility as the program administrator. Through a collaborative effort, the customer would benefit from a single source of contact, a straightforward rebate process, and a richer incentive, thus driving results.

21. Enbridge is currently working with GreenON and the IESO to collaborate on a joint program, which will improve cost effectiveness, deliverability, and customer satisfaction.

<u>Section 2: Prioritization of Market Transformation Programs</u>

22. Enbridge and Union Gas were directed by the Board to respond to the following request:

> For the mid-term, the OEB would expect the utilities to provide an internally-derived summary of market needs to demonstrate how the selected Market Transformation programs were prioritized and targeted to close those gaps[2].

[2] EB-2015-0029/EB-2015-0049, Decision and Order, January 20, 2016, p. 33

23. Enbridge is well connected with its customer base. The Company is continually communicating with customers and stakeholders to understand their evolving energy efficiency needs. As part of this on-going dialogue, the Company has identified market needs in energy literacy, energy use behaviours and new construction. In the Company's 2015-2020 DSM Plan, select programs such as behavioural and customer bench marking offers were proposed as programs that aligned well with the Market Transformation objectives as set by the Board in the DSM Framework[3]. Despite the above mentioned program offers' fit within the Market Transformation agenda of the Framework, the Board ultimately rejected the offers for other reasons.

24. Behavioural programs have been successful in other jurisdictions throughout North American and the Company believes that this success can be replicated in Enbridge franchise area. Although the behavioural program applied for in the Multi-Year Application was rejected by the Board, the Ministry of Energy (MOE) has partnered with the Enbridge to deliver a behavioural program through the Green Investment Fund (GIF). Learnings from this initiative will be used to inform any potential future programming in the post-2020 DSM Framework.

25. Enbridge Gas Distribution is currently experiencing an annual growth rate of approximately thirty thousand new buildings (all sectors) per year. Given this growth rate, the new construction market is an important priority for Enbridge's DSM offerings. Constructing new homes to use energy efficiently provides long term energy savings and corresponding GHG reductions. If not captured during new construction, it could be many years and possibly decades, before higher energy efficiency retrofits are implemented at significantly higher cost. As a result,

[3] EB-2014-0134, Filing Guidelines to the Demand Side Management Framework for Natural Gas Distributors (2015-2020), December 22, 2014, p.13-14

Enbridge believes both the residential and commercial new construction programs are high priority market transformation initiatives.

26. As part of the Savings by Design programs, the Company is in regular communication with the new construction industry. This on-going dialogue has helped to identify market needs that will drive the highest level of energy efficiency for the new construction industry. Today, builders are saying that home buyers are not asking for premium priced energy efficient homes, but that their primary interest is simply to own an affordable home. In short, the market demand from the majority of prospective homebuyers for premium energy efficiency homes is moderate. As a result, to influence the new construction market, the energy efficiency program focus needs to be directed to influencing builders to build energy efficient affordable homes. That said the Company recognizes the need to remain agile and responsive to the quickly changing market place.

27. On-going dialogue with builders, municipalities and property owners and property managers has confirmed that the Integrated Design Process (IDP) adds substantial value and positively influences higher levels of energy efficiency. An IDP involves bringing a multi-disciplinary team of experts together for a design charrette at the early design stage to undertake a holistic review of all building envelope and mechanical systems with the goal to optimize energy efficiency performance. More specifics are outlined in Section 9.2 of this submission.

Section 3: Open Bill Access

28. In the DSM Multi-Year (2015-2020) Application, the Company outlined a series of events that influenced its decision not to develop an On-Bill Financing Program

(OBF)[4]. In the Decision, the Board agreed with the Company's position and acknowledged it did not view

> access to financing as a critical deterrent to customers participating in conservation programs. Therefore, the utilities should not assume the role of providing financing to their customers[5].

29. The Board however was encouraged by Enbridge's existing Open Bill Program (OBP), noting its several advantages for customers while avoiding negative risks to the utilities profile. The Board directed Union Gas to work with Enbridge to establish a similar capability on its bills, and directed Enbridge to "expand access to third parties to use the utility bill for conservation related services"[6].

30. The Company worked with Union Gas to support development of an Open Bill Access program for their customers. Details of Union Gas's Open Bill Access program can be found in its January 15th, 2018 Mid-Term Submission (EB-2017-0127).

31. Enbridge began offering the Open Bill Access program in 2009 and it continues to this date. The program is comprised of two components: Billing Services and Bill Insert Services. Enbridge offers Billing Services to third parties (including financing institutions) whereby Enbridge allows the third party billing to appear on the customer's bill. Enbridge then collects the amounts payable on behalf of the participating third party for a small fee. Bill Inserts Services allows third parties to advertise in the Company's residential customer paper and electronic billing.

32. The Open Bill Access Program has been in operation for 9 years and provides billing and collection services to over 130 HVAC and energy services vendors

[4] EB-2015-0049, Enbridge Multi-Year DSM Application (2015-2020), Exhibit B-4-3
[5] EB-2015-0049, Decisions and Order, January 20th, 2016, p.54
[6] EB-2015-0049, Decisions and Order, January 20th, 2016, p.55

across Enbridge's franchise territory. In 2016, the Company added 27 new participants to the program as it sought to expand participation as broadly as possible across the industry. To encourage participants to join the Open Bill Access program, the Company distributes promotional materials to contractors, retailers, industry associations, and advertisers at trade shows, and relies on the positive word of mouth among third party participants.

33. The Company is still receiving and accepting new participants each year, with 15 new participants joining in 2017. The requirements to join the program are easy and do not pose barriers to joining. Requirements include a basic background check (confirming legal entity and basic financials), confirmation of good standing with the Better Business Bureau and Ministry of Consumer Affairs, a documented customer complaint management process, and a $2,500 deposit. The Company believes that these requirements create an easy to access program that is inviting to potential third party participants of all types.

Section 4: Out-Come Based Metrics

34. In s9.2 of its January 2016 Decision and Order , the Board made the following observation:

> The OEB generally considers outcome -based performance standards to be the most relevant and appropriate when determining the success of a given activity. Lifetime natural gas savings should continue to be the primary goal of the gas utilities' DSM program efforts. Additional outcome-based metrics might be included on performance scorecards to ensure that the programs have been designed in an efficient manner and are providing the results that support the primary goal of DSM: to reduce overall natural gas consumption. The OEB suggests that the gas utilities work with stakeholders to develop options for additional outcome-based metrics for consideration at the mid-term review[7].

[7] EB-2015-0049 (2016), Decisions and Order, Ontario Energy Board, p.65

35. Enbridge acknowledges the Board's suggestion, as well as the merits and implications of outcome-oriented, performance-based metrics ("PBM"). In comparison to gas savings expressed in annual (m3) or lifetime cumulative cubic metres (CCM), PBMs provide an alternate understanding and measurement of the effects of DSM on society.

36. Prior to and during the 2015-2020 DSM Plan proceedings, Enbridge and the Board heard recommendations from intervenor groups advocating for the development and addition of PBMs to the Company's DSM scorecard. In its Decision, however, the Board largely approved Enbridge's proposed metrics, namely:
    - Cumulative natural gas savings (Custom and prescriptive projects, and other offers)
    - Residential deep savings participants (Home Energy Conservation)
    - Project Applications (Low-income New Construction)
    - Schools enrolled (School Energy Competition)
    - Participants (Run-it-Right; Comprehensive Energy Management)
    - Builder participants and homes built (Residential Savings by Design)
    - New developments (Commercial Savings by Design)
    - The Board also established a 10% productivity improvement factor for all Market Transformation and Performance-Based metrics.

37. As part of its on-going attention to performance improvement and in preparation for the Mid-Term proceeding, Enbridge examined its current suite of programs to better understand whether alternate or additional metrics are appropriate at this time. A sample of the PBM's Enbridge considered included:
    - customer feedback
    - usage
    - beliefs / values

- satisfaction scores
- records
- operational
- maintenance
- purchase
- travel
- utility bill
- measurement / metered (in person or automated)
- total building gas consumption
- total building gas cost
- total building water consumption
- total building water cost
- gas consumption per site area
- gas consumption per occupant
- gas consumption per litre of hot water
- litres of hot water per occupant
- metric ton CO_2e / site area
- gas consumption per hour, day, week, month, year
- cost per cumulative cubic metre
- cost per metric ton CO_2e

38. Beyond the significant cost and logistical / administrative challenges associated with developing and installing time-of-use, interval “smart” metering infrastructure across Enbridge’s franchise area (mostly involving residential customers), Enbridge’s analysis of the benefits of metered consumption data does not present a convincing case for DSM at this time. Although using metered data is possible, it does not necessarily equate to greater certainty for DSM. The Company maintains

continuing to use engineering assumptions is still the most simple, least expensive and practical method for DSM at this time.

39. As such, the Company believes the current set of program metrics continue to appropriately and reliably report performance in DSM. Enbridge continues to foster relationships with customers and business partners to keep a pulse on how DSM is being experienced. This helps inform whether a change in metrics is needed to better reflect effects of DSM in the Company's franchise area. For the remainder of the 2015-2020 Plan Enbridge proposes to use its existing metrics, and will revisit new PBM's at the post-2020 Framework.

Section 5: Target Adjustment Mechanism (TAM) and Other Scorecard Enhancements

40. In the Report of the Board: Demand Side Management Framework ("Framework"), the Board provided guidance on how the gas utilities should formulate annual and long-term natural gas savings targets for 2016 to 2020 (2015 was a rollover of 2014 targets)[8]. The Board stated that the "natural gas utilities possess a significant amount of relevant and critical information that will allow them to appropriately develop and propose performance targets…and that the gas utilities will rely on their… experience-to-date and projected market opportunities and constraints to inform the development of their annual and long-term natural gas savings targets."[9] Adopting this approach, Enbridge developed targets based on real market experience that were aggressive and appropriate for the program activities planned in its DSM Multi-Year (2015-2020) Plan.

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[8] EB-2014-0134, Report of the Board Demand Side Management Framework for Natural Gas Distributors (2015-2020), December 22, 2014, p. 37

[9] EB-2014-0134, Report of the Board Demand Side Management Framework for Natural Gas Distributors (2015-2020), December 22, 2014p. 12

41. During the Multi-Year DSM proceeding, some intervenors commented that the Companies proposed targets were "not sufficiently aggressive"[10]. The Board responded by increasing the Company's 2016 targets by 10%, without a proportional increase in budget, and applied a target adjustment mechanism (TAM) that would formulaically reset the 2017-2020 targets; inclusive of productivity factors. The TAM would calculate new targets based on the dollar spent per cubic meter (or similar) of savings achieved in the prior year to produce new targets that reflected the cost-efficiencies found in the prior year.

42. The Company will demonstrate in this evidence that the Board's new approach to target setting has resulted in unwelcome implications for the Company's ability to deliver DSM. Pursuant to the Board's direction in the Mid-Term Review Letter, "Union and Enbridge [are] to provide suggestions on appropriate changes to the target adjustment formula.[11]" In this evidence, the Company outlines the implications produced by the 2016 10% target increase and adjustment formula. In response, Enbridge proposes a set of enhancements that will support a more practical application of the TAM and target setting; thus improving program delivery. The Company offers further enhancements to the scorecard, resulting from the requirements as set previously by the Board in the October 1st, 2017 submission.

Budget Implications

43. In the Multi-Year (2015-2020) DSM Application, the Company proposed annual targets for 2016 – 2020 developed from the Company's expertise and 20 year experience delivering DSM. The corresponding budgets for each program reflected the target to ensure that an adequate amount of funds would be available to

[10] EB-2015-0029/49, Decision and Order, January 20, 2016, p.66
[11] DSM Mid-Term Review (EB-2017-0127 and EB-2017-0128), Ontario Energy Board, June 20, 2017

promote the DSM activities, drive results, and fund the incentives owed to participants. However, the 10% target increase in 2016, as directed by the Board, without a proportional increase in budget created a fundamental mismatch between the incentive budgets required to support the target and the approved budget available.

44. Articulated in the Company's previous Written Comments to the Board on February 3rd, 2016, Enbridge emphasized for the Board the unintended consequence of this target increase using the example of the Home Energy Conservation (HEC) program offer. The participant target for 2016 was increased by 10% resulting in 751 more participants. Within the HEC offer customers can receive up to $2,100 in incentives for energy audits and upgrades. The increase in target meant that approximately $7.9 million unbudgeted amounts would be needed for the incentive payments to pay additional participants over the course of the 5 year Plan.

45. Consistent with the comments made by the Company in its February 3rd Written Comments, Enbridge notes for the Board that one of the implications of increasing target without increasing budget, is that the Company becomes forced to borrow funds from other programs. The result has been a shift in focus and attention towards certain programs and sectors at the expense of others.

46. The Company understands the Board's intention was to drive the Company to be more cost-effective while pursuing aggressive results yet the distinction was not made between the financial incentives to be paid to participants and the cost of operating the program. Incentive payments to participants are fixed amounts that cannot be altered to achieve cost-efficiencies without compromising the success of a program. To realize cost-efficiencies, without decreasing incentives, the Company's only method would have been to find efficiencies in the Administration and Overhead (A&O) budget.

47. However, the Board's method of removing the associated A&O costs of the rejected program offers left little to no cost-efficiencies to be found in the current A&O budgets. While the Company agrees that it was appropriate to remove the A&O costs of a rejected program from the budget, the Board made adjustments to the utilities' A&O budgets which were mathematically commensurate to the offer's program budget instead of proportionately commensurate to the actual contributing A&O costs of each respective rejected offer. This approach resulted in an overall reduction of A&O costs that were greater than what was needed to deliver the rejected program offers.

48. Specifically, the Board reduced Enbridge's 2016 Overhead budget by $1.06 million; $1.015 million of which was removed from the Company's Market Transformation and Energy Management (MTEM) Overhead budget. It is important to recognize that the majority of the reduction in program budget which drove the Board's reduction of Enbridge' s A&O budget related to the cancellation of the Company's My Home Health Record (MHHR) program; a program delivered largely by a third party. The MHHR program was responsible for only a minimal portion of Enbridge's A&O costs, certainly far less than the $1.015 million removed. Enbridge suggested to the Board in its February 3rd Written Comments that, rather than reduce the MTEM A&O budget by a mathematically derived $1.015 million due to this program's cancellation, the budget should be reduced by MHHR's contribution to A&O costs. As noted in evidence, the A&O budget for this program was only $337,000[12]. In its Revised Decision and Order dated February 24, 2016, this relief was still not addressed.

[12] EB-2015-0049, Enbridge Gas Distribution, Written Comments and Draft Accounting Order, February 3, 2016, p.15

49. To manage the fundamental mismatch between budgets and target the Company looked for strategies to mitigate the budget deficit and continue to deliver programs that produced meaningful results. As outlined above, Enbridge was forced to re-direct funds at the expense of others in order to pay the participant incentive amounts owed to achieve target and keep program momentum throughout the year. For example, to maximize results the Company believed that it best served ratepayers by allocating funds away from the Small Commercial New Construction pilot to more mature offers that were currently in market. The Company believed the value for ratepayers was more certain by not launching the pilot in 2016, and instead using that budget to pursue results in other program offers that had been fully designed, launched, and evaluated for cost-effectiveness.

50. For clarity, although the Framework contemplates 30% budget mobility[13], the distinction should be made behind the motivation to move budget in this circumstance. The Company, in many scenarios in 2016 and 2017, shifted budget to compensate for a lack of incentive dollars to achieve target; versus solely in the pursuit of continuing momentum for an exceptional program year.

51. As stated in the Company's September 1st, 2017 submission, the Company proposed that either a 10% budget increase or a 10% target decrease should be applied to the 2018 sales year to help restore the budget and target balance[14]. In this submission, the Company is proposing that should the Board the 10% budget increase that 10% total annual program budget be included effective January 1st, 2018; as shown in Appendix C: Revised Enbridge Budgets 2018-2020. The Company proposes that this 10% budget increase be reflected as a line item that can be spent on the programs that require an increase in incentive budget to

[13] EB-201-0134, Filing Guidelines to the Demand Side Management Framework for Natural Gas Distributors (2015-2020), p.15
[14] EB-2017-0128, DSM Mid-Term Review, September 1st, 2017, p.25

continue achievement, such as HEC. This flexibility is consistent with the budget mobility permitted under the DSM Framework and enables the Company to achieve target and continue momentum for programs throughout the year without diverting attention to one offer at the expense of others[15].

52. It is important to highlight the fact that this proposed 10% increase in program budget could not be used for overhead. It would be available solely to cover program costs like the customer incentives payable to the increased number of program participants.

53. A 10% increase in budget, however, is only part of the solution to realign budgets and targets. Due to the effects of the TAM, target setting is now unpredictable, and can become out of sync with the budget required to meet the new heightened, and sometimes artificial, levels of target.

Target Implications

54. In the Decision, the Board agreed with the utilities that setting long term targets is particularly challenging given the evolving energy policy objectives within Ontario. The Board also noted that "setting firm targets for 2016 to 2020 is particularly challenging given the dramatic increase in program funding and the introduction of new [DSM] programs[16]." The Company proposed reasonable, yet aggressive targets in the Multi-Year Plan, however the Board directed instead that the utilities adopt a target adjustment mechanism (TAM) that would formulaically re-set annual targets based on the previous year's results; thus eliminating fixed targets for the Plan.

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[15] EB-2014-0134, Filing Guidelines to the Demand Side Management Framework for Natural Gas Distributors (2015-2020), December 22, 2014, p.15
[16] EB-2015-0029/49, Decision and Order, January 20th, 2016, p. 69

55. As stated earlier, the TAM reflects the cost-efficiencies found in the previous year's results, and sets the new targets based on cost per cubic meter (or similar), escalated by a productivity factor. This formula does not account for changes in the marketplace that can occur in a given year, nor does it acknowledge the law of diminishing returns. For mature and specialized offers, each year is more difficult than the last to achieve more results as the level of effort must increase, thus becoming more expensive. For example, in year one a program may have achieved target using less budget, and the TAM interpreted this success as a sustainable cost effective program, thereby calculating an even higher target for the following year. For most programs, this escalation year over year is not sustainable in the market place, as the outcomes from year one is not a predictor of the outcomes of year two or year three.

56. A key point which must be identified is that regardless of the cause, if a target increase changes the total customer incentives payable given an objective of more participants, the funding for the increase in customer incentives must exist. If the same levels of customer incentives paid in year one which resulted in a successful year are to be paid out in year two, the increase in customer incentives must be added to the program budget. Reducing the level of customer incentives is not a cost efficiency measure but rather is more likely to significantly reduce the program's success.

57. For example, in 2016 the Low Income New Construction program (LINC) target was 6 participants (inclusive of the 10% increase). In 2016 however, funds from the program were diverted to other programs to compensate for the lack of incentive budget required in that year. As a result, the LINC budget is shown as "underspent." As this program was new to market, with multi-year payouts, the program did not require the entire budget in year 1, because it included budgeted

amounts for incentives payable in future years. As there is no current accounting mechanism to roll these amounts over into future years where it is needed, rather than return the unpaid amounts, they were diverted to programs that needed budget in that year.

58. For the LINC program, the Company's pre-audited calculation using the TAM shows a massive swing in target that jumps to 28 Project Applications for 2017. In the Companies Multi-Year Plan, the original LINC targets escalated annually by 2 additional projects per year (i.e. 2016 = 5 projects, 2017 = 7 projects, 2018 = 9 projects). These targets were based on the Company's best available knowledge of what was realistic in this marketplace. For example, government funded low income housing developments do not increase substantially year after year. Even more important is that the 2017 budget is not enough to support 28 Participants and therefore the Company would not have the funds to fulfill its obligation to participants and achieve 100% target. In fact the Company does not have the ability to reach even the 75% lower thresholder of 21 project applications. There is simply no scenario in which Enbridge would earn DSMI. Consistent with the sentiments expressed in the Company's September 1st Submission, any pure rational economic actor would walk away from this scenario and refocus efforts on other programs to reach performance targets[17].

59. The increase in target for the LINC program is exacerbated by its multi-year incentive payout schedule. Programs with deferred incentive payouts that span several years require proper multi-year budget management to ensure that the funds are available when the participant is owed the incentive. Absent the Demand Side Management Participant Incentive Deferral Account (DSMPIDA) that was not acknowledged by the Board in the Decision, the Company has no mechanism to

[17] EB-2017-0128, DSM Mid-Term Review, September 1st, 2017, p.18

carry-over budget to ensure that incentive funds are available when they come due. This is especially detrimental to the Company's ability to deliver if the targets are inflated from 6 to 28. There simply will not be enough budget to sustain that level of achievement – especially, without a mechanism to carry-over budget and manage payouts appropriately. This scenario is counter to the provisions provided by the Board in the Framework:

> The Board acknowledges that DSM targets and DSM budgets are closely related. In order to have a reasonable expectation that a particular target is attainable, a corresponding budget that has appropriately taken the targeted level of activity into account is necessary. It is important to consider the impacts both targets and budgets have on each other. In the event that the budget is not sufficient, the targeted goals may be inappropriate and overall results will be less than expected[18].

60. The massive target increases (compared to what the Company can achieve within the approved budget) creates a scenario that despite the Company's strongest efforts, there is no possibility of earning DSMI for the program offer. The DSM Framework must give the Company a reasonable opportunity to earn DSMI to make all DSM program offerings a good business decision. Ensuring the utilities are properly motivated is good for ratepayers by encouraging the Company to pursue a range of program offers with broad impacts and benefits for a society that has a price on carbon emissions.

61. The TAM in its current state gives little to no reason for the Company to spend efforts on the Low Income portfolio, as the new targets are unreasonable and unsustainable. For the Company to earn DSMI in program offers with unreasonable targets means that the Company's only recourse in a world with TAM is to underperform in one year knowing that it will produce a reasonable target the following year (e.g. low achievement divided by high cost produces a low cost effectiveness value, producing low target for the following year). This is not a

[18] EB-2014-0134, Demand Side Management Framework for Natural Gas Distributors (2015-2020), p.14

gaming of the formula; it is simply the foreseeable necessary consequence of the inevitable impact of the current TAM.

62. The Company does not believe in gaming the TAM, nor does it want to turn attention to one sector at the expense of another in order to improve the earnings prospective from a portfolio basis. The Company wants to successfully deliver each program, which will have lasting impacts in each sector. However, the TAM in its current state reduces the earnings potential in some program offers and dis-incents the Company from pursuing such program offers.

63. Further, the use of the TAM as instructed by the Board in its Decision is not practical in application. In the Decision the Board states that "verified LRAM savings" must be used as the input into the TAM calculator[19]. At the time of the Decision, the Board had yet to fully take over the evaluation and audit process, and could not have foreseen how delayed the process would come to be. As a result of substantial evaluation delays, the Company is not able to apply the verified LRAM savings into the TAM calculator to get next year's targets in a reasonable timeframe. For example, 2016 results have not been finalized, and therefore at the time of this submission (January 15th, 2018), the Company still does not know true 2017 targets.

Proposed Enhancements

64. In response to the issues identified above, the Company has prepared a set of enhancements to the target adjustment mechanism to improve the Company's ability to deliver maximum achievement for ratepayers.

[19] EB-2015-0029/0049, Decision and Order, January 20th, 2016, Schedule C

Programs with Deferred Incentive Payouts to be Exempt from the TAM

65. Programs with deferred incentive payouts are challenging to manage from the perspective of the program administrator because the targets do not align with the budget payout. Participants enroll in a program, and subject to the rules and structure of the program, typically do not claim their incentive until three to five years later. The Company needs to manage the annual budget to account for participants that will claim incentive payouts in future years.

66. From the perspective of the TAM, for a program year where participants have not claimed incentive payouts, the budget will be “underspent”, thus appearing to be more cost-effective than the cost per participant (or similar) actually is. In other words, the TAM calculator will interpret this “underspend” as a cost-effective spend, when in truth the spend is simply deferred to a future year for payout to the participant (i.e. target) that enrolled in the present year. Using these inputs, the TAM calculator will produce targets that are artificially high/low and not reflective of the true cost per participant (or similar).

67. The Company proposes that programs with deferred incentive payouts be exempt from the TAM calculator. The TAM calculator is not appropriate for programs with deferred incentive payouts because the target and budget do not align, thus causing an artificial cost per participant (or similar) in the TAM. In its place, the Company has filed the fixed targets, as proposed in the Plan (escalated by 10% + annual 2% productivity factor), for each program with deferred payouts to ensure realistic targets for each program are set.

68. These fixed metrics have been filed in Appendix B: Revised 2018-2020 Metric Weightings. The Company continues to believe that the targets filed as part of the Multi-Year DSM Plan remain appropriate as the targets are achievable, yet

aggressive. However, in compliance with the Decision, the Company has inflated the fixed targets by 10%, and included an annual productivity factor of 2% effective 2018. While these increased targets have been a source of great concern to date, without the 10% increase in program budget as proposed, these increases would likely result in a material reduction or in some cases the end of some programs for want of funding. With the 10% increase in program budget and fixed targets going forward, Enbridge believes it can maintain a full portfolio of these types of programs. These fixed targets going forward will ensure that these programs have targets that are realistic and not artificially inflated further due to the deferred budget payouts. Were the Company to attempt to achieve the artificially heightened targets it would require that the Board increase the budgets substantially.

Fixed Net to Gross Value

69. Previously, as directed by the Board, the evaluation process related to DSM programs had been a function that the gas utilities had managed, with input from stakeholders included throughout the process. For the Multi-Year DSM (2015-2020) Framework the Board concluded that it was instead "in the best position to coordinate the evaluation process throughout the DSM framework period"[20] in collaboration with the gas utilities, supported by stakeholders with technical expertise. The Multi-Year Guidelines further specified that "the Board will take on the coordination function of the EM&V process."[21]

[20] EB-2014-0134, Report of the Board, DSM Framework for Natural Gas Distributors (2015-2020), December 22, 2014, p. 30
[21] EB-2014-0134, Filing Guidelines to the DSM Framework for Natural Gas Distributors (2015-2020), December 22, 2014, p. 15

70. The Board subsequently issued two letters on August 21, 2015 and March 4, 2016 which further outlined the new evaluation process and the transition of the activities of the TEC to the OEB. Another letter from the Board dated March 4, 2016 outlined the transition of the, then current, ongoing DSM evaluation activities from the TEC. Before the formation of the EAC, and the hiring of an Evaluation Consultant, a number of important evaluation activities were already underway. Among several key projects, the Custom Commercial and Industrial Net-to-Gross (NTG) study was in progress. The TEC had previously completed a Request for Proposal ("RFP"), initiated a selection process, and had contracted DNV GL (previously DNV Kema) ("DNV") in May 2015 to complete the study. The TEC had resolved that "the primary objective of this project is a transparent, reputable study that produces strong, credible, and defensible NTG ratios to be used on a go-forward basis[22]."

71. In April 2016, the Board selected the Evaluation Contractor. The May 5, 2016 email outlined that the OEB Staff had engaged DNV GL as the OEB's Evaluation Contractor. It indicated that among the EC's responsibilities, DNV would oversee the annual verification of the 2015 DSM program results, including preparing a Final DSM Results Report.

72. The 2015 EM&V process took approximately 18 months (it should be noted however that in this timeframe the NTG study was not completed, as the spillover component of the study is as yet incomplete). Under the new OEB Staff led EM&V process, almost 22 months after the end of the utilities' 2015 program year, the OEB issued two reports on October 16th, 2017, developed by the OEB's Evaluation Contractor, DNV GL, providing 2015 Demand Side Management (DSM) verification results.

[22] Measurement of NTG Factors for Ontario's Natural Gas Custom Commercial and Industrial DSM Scope of Work for Ontario Natural Gas Technical Evaluation Committee (TEC), dated March 2, 2016, p.

73. The Company uncovered a number of errors made by the EC in its calculation of verified 2015 DSM program results including its determination of DSM shareholder incentive. Enbridge communicated these concerns to Board Staff and the EC on November 20, 2017. The EC has since acknowledged these errors, which has also been communicated to the EAC. The EC is expected to update its report with the corrected values.

74. The problems and delays were not specific to 2015, and in fact have had a domino effect on 2016 EM&V process. On March 15th, 2017, Enbridge received a letter notifying the Company that the 2016 Draft Evaluation report would be delayed from April 1st, 2017 to "one month following the OEB's release of the 2015 results[23]." The Board noted that pushing back the 2016 EM&V process would allow the gas utilities to "incorporate any relevant findings from the 2015 evaluation process." The Board did not release the 2015 evaluation results until October 16th 2017, and therefore the 2016 Draft Evaluation Report was not filed until November 16th 2017.

75. These are substantial delays uncommon to the past utility-led EM&V process, and have produced significant challenges for the Company, including not having verified results as inputs into the TAM within a reasonable timeframe. The sequence of events detailed above is illustrative of a dysfunctional EM&V process. The delays resulting from the shifting accountability to the Board has led to a series of unfortunate delays that are compounded year over year, providing instability to the Multi-Year Plan. The delays not only affect the Clearance of Accounts, but it impacts the Company's ability to properly plan for the following year.

[23] Letter of the Board: 2016 DSM Draft Evaluation Report, Ontario Energy Board, March 15, 2017

76. For illustrative purposes, the following is the TAM formula provided by the Board in the Decision to annually adjust targets for the 2017 Resource Acquisition scorecard:

2016 metric achievement (LRAM natural gas savings) / 2016 actual program spend without overheads x 2017 budget without overheads x 1.02[24]

77. The Board instructed that "metric achievement is equal to the final verified program results following the annual program evaluation[25]." In practice, this means the Company is retrospectively calculating targets due to the substantial delays in determining verified savings. To retrospectively apply targets means the Company is offering programs blind. This is unfair to the utilities who need to know at the beginning of the program year what the sales targets are to ensure they properly expend marketing efforts and resources to respective programs.

78. Further demonstrated in the narrative above, is a burdensome process that requires dedicated resources and additional costs to a lengthy evaluation process and annual net to gross studies. An annual net to gross study is unnecessary, as the methodology currently employed by the Board is antiquated and does not reflect the current policy environment in which energy programs are run. To reiterate the points made in the September 1st submission, applying "inaccurate free-ridership rates, acts as a significant impediment to abatement activities at exactly the time when policy makers, market players, and customers are working to maximize abatement[26]."

[24] EB-2015-0029/49, Decision and Order, January 20th, 2016, Schedule C
[25] EB-2015-0029/49, Decision and Order, January 20th, 2016, p.72
[26] EB-2017-0128 DSM Mid-Term Review Comments of Enbridge Gas Distribution, September 1st, 2017, p. 23

79. A fixed net to gross value modernizes the evaluation process, and provides the stability the Company needs to operate effectively for the benefit of ratepayers by streamlining the EM&V process. Articulated in the Company's September 1st Mid-Term Submission, establishing "a fixed rate would have the dual benefit of creating a stable, fair, and transparent business environment that is required in order for the utilities to continue to deliver successful results, while maintaining the inclusion of net to gross for the purpose of calculating cost-effectiveness and reporting on the energy saving outcomes of DSM activity[27]."

80. The Company is of the position that to comply with the Board's direction of using verified savings as an input into the TAM, a fixed net to gross must be applied. Enbridge therefore recommends applying a fixed net to gross adjustment of 70-80% (or a free-ridership rate of 20-30%) for programs other than Low Income, which should be subject to 100% net to gross (0% free-ridership). This is consistent with the input assumptions filing, and consistent with the rates applied by the IESO for CDM programming[28].

<u>Consistent Productivity Improvement Factors</u>

81. In the Decision, the Board applied two sets of productivity improvement factors to be calculated as part of the TAM. For offerings in the Resource Acquisition program scorecard, and offerings in the Low Income program scorecard, a productivity factor of 2% is applied within the TAM. For offerings within the Market Transformation and Energy Management program scorecard, a productivity improvement factor of 10% is applied within the TAM. The Board applied the productivity factors to "promote continued efficiency in program delivery.[29]"

[27] EB-2017-0128 DSM Mid-Term Review Comments of Enbridge Gas Distribution, September 1st, 2017, p. 21
[28] EB-2017-0128 DSM Mid-Term Review Comments of Enbridge Gas Distribution, September 1st, 2017, p. 21
[29] EB-2015-0029/49, Decision and Order, January 20th, 2017, p. 69

82. The Board explained that the productivity improvement factor be "more aggressive for MTEM metrics as these programs tend to be newer programs with more opportunity for improvement[30]." The Company is already naturally incented to maximize achievement per dollar spent and the compounded productivity factor creates further stress to the already inflated targets. As previously noted by the Company in its Written Comments' of February 3rd, 2016, the Residential and Commercial Savings By Design and the Run it Right programs are mature offerings that have been in the market for several years. These are not net new programs in untapped markets with exponential potential and room for improvement. The reality of the market is such that there are only so many eligible buildings for the programs and a higher productivity factor will not change this.

83. The Company proposes that the 10% productivity factor that is applied to the MTEM program be reduced to 2% to be consistent with the RA and LI program offerings.

Scorecard Enhancements

Revised Metrics and Targets

84. The Company submits that programs with deferred incentive payouts be exempt from the TAM for the reasons outlined within that section. In its place, the Company has proposed that the following programs have fixed targets effective 2018 to 2020:

- SBD Commercial – New Developments Metric
- SBD Residential – Builders and Homes Built Metrics

[30] EB-2015-0029/49, Decision and Order, January 20th, 2017, p. 70

- School Energy Competition – Schools Metric
- Run it Right - Participant Metric
- Comprehensive Energy Management - Participant Metric
- Low Income New Construction - Participant Metric

85. The fixed targets proposed in Appendix A: Revised Enbridge Scorecards and Targets 2018-2020 are the targets filed in the Company's DSM Multi-Year Plan, inflated by a 10% increase and multiplied by a 2% annual productivity factor to remain consistent with the treatment applied in the Board's Decision and the Company's proposal in the section above.

Revised Metric Weightings

86. In the Mid-Term Requirements, the Board directed Enbridge to move the Run It Right (RiR) program to the Resource Acquisition Scorecard. The Company filed the Run It Right program in the Multi-Year DSM Plan with a CCM and Participant metric that were split between Resource Acquisition (RA) scorecard and Market Transformation and Energy Management (MTEM) scorecard. The Company complied with the direction in its October 1st Submission, and agreed to move the MTEM Participant metric to the RA scorecard[31]. In that submission, the Company outlined its intention to submit a scorecard revision, and subsequent redistribution of scorecard weighting, in this January 15th, 2018 Submission.

87. The same request was made of the Comprehensive Energy Management Program (CEM). The participant metric as filed in the MTEM scorecard was also directed by the Board to be moved into the RA scorecard. The Company outlined its

[31] EB-2017-0128 DSM Mid-Term Review Comments of Enbridge Gas Distribution, October 1st, 2017, p.30

agreement in the October 1st, 2017 Submission, with a commitment to revise the scorecards as part of this submission.

88. As demonstrated in Appendix B: Revised 2018-2020 Metric Weightings, the RiR and CEM participant metrics have been moved to the RA scorecard. As a result, the metric weightings have been adjusted within the RA and MTEM scorecards to reflect the change. RiR and CEM have been given a new weighting of 7.5% each, and the other RA offers have been deducted an appropriate amount to equal 100% on a Program Scorecard basis. Similarly, the MTEM programs have been allocated more weight to compensate for the loss of the two metrics of RiR and CEM to create a balanced weighted scorecard.

Revised Shareholder Incentive Weightings

89. In 2016 and 2017, the Run it Right and CEM Programs were measured in two ways. First, to recognize the importance of driving engagement and participation a participant metric are captured within the MTEM program scorecard. Second, the CCM metric captured the natural gas savings and are already included within the RA program scorecard. Therefore, to comply with the Board's direction the Company moved both the RiR and CEM participant metrics to the RA program scorecard.

90. Moving both the RiR and CEM program and participant targets to RA resulted in a reallocation of budget from MTEM to RA. The Company is proposing that the corresponding re-distribution of scorecard weighting be appropriately valued for the remaining MTEM programs.

91. As outlined in the Company's October 1st submission, as a function of the total incentive available to the Company to deliver DSM, the relative value of the MTEM

Program, even before this recent change removing RiR and CEM from the MTEM scorecard, the scorecard weighting in the Company's view was below an appropriate level. The Company understands the Board's reasoning to not approve programming it deemed not consistent with the DSM Framework, however, the Written Response Enbridge filed on February 3, 2016 remains valid in the Company's submission;

> Enbridge submits that the unintended consequence of removing the several MTEM offerings which contributed only modestly to the MTEM shareholder incentive, and then adjusting the allocation of the shareholder incentive to MTEM by the decrease in budget rather than the rejected offerings metric weighting, results in the disproportionate decrease in the MTEM shareholder incentive thereby devaluing the continuing MTEM programs[32].

92. The American Council for an Energy Efficient Economy (ACEEE) views Market Transformation (MT) as a key component of a DSM portfolio. The value is demonstrated by the fact that American Council for an Energy Efficiency Economy (ACEE) has held an annual National Symposium on MT since 1999[33] and covers this topic in a number of papers[34]. In light of the importance of these market transformational programs as outlined in the DSM Framework and given the clear priorities of the Government of Ontario, (Cap & Trade, CCAP, the Conservation Directive, etc.), Enbridge believes MTEM should be appropriately valued and weighted to ensure Company focus[35].

93. Using the methodology used in the 2016 scorecard to weight the shareholder incentive per program, the loss of two metrics on the MTEM scorecard resulted in the MTEM Program becoming undervalued on a portfolio basis. The Company therefore proposes that the Board approve a different methodology to rebalance

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[32] EB-2015-0049, Multi-Year Demand Side Management Plan (2015-2020) Written Comments, February 3, 2016, p.3

[33] https://aceee.org/conferences/2010/mt-past

[34] https://aceee.org/portal/market-transformation

[35] EB-2014-0134 "Filing Guidelines to the Demand Side Management Framework for Natural Gas Distributors (2015-2020), December. 22, 2014, p.13

the value between the program scorecards, and to ensure that the MTEM programs are appropriately valued given the Board's requirement to move offerings[36]. By valuing the MTEM appropriately, the Company has reduced the RA weighting slightly to allow for a fair distribution of among all three programs that reflects the value each offer provides to its participants. It is imperative that the programs are appropriately valued to ensure that the Company has incentive to offer all program offerings for the benefit of ratepayers. The Company is proposing a revised MTEM weighting for 2018-2020 of 20%.

94. This approach is consistent with the previous values assigned to the programs in the previous Frameworks. As demonstrated in Table 1, Market Transformation in years 2012-2014 was given a more balanced and fair valuation among all programs.

Table 1 – 2012-2014 Shareholder Incentive Weightings per Program[37]

	2012	2013	2014
Resource Acquisition	61.64%	58%	58%
Low Income	22.73%	23%	23%
Market Transformation	15.64%	19%	19%
Total	100%	100%	100%

95. The Revised Shareholder Values can be found in Appendix B: Revised 2018-2020 Metric Weightings.

[36] DSM Mid-Term Review (EB-2017-0127 and EB-2017-0128), Ontario Energy Board, June 20, 2017
[37] EB-2012-0394, Exhibit B-1-2, p.2, Enbridge Gas Distribution Update to the 2012 to 2014 Demand Side Management Plan, February 28th, 2013

Budgets

96. In the Decision, the Board requested that the Company propose 2018-2020 budgets for the Energy Leaders Initiative and the Energy Literacy Fund pending the success of the 2016 and 2017 program years. As detailed in the October 1st, 2017 Submission, the Company was able to incent deeper measures through the Energy Leaders Initiative, and was able to promote enhanced energy literacy among Ontarians using available funds through the Energy Literacy Fund.

97. The Company therefore, is proposing that the same level of funding approved for 2016 and 2017 remains appropriate for 2018-2020. The Company has added the following budgets to the remainder of the Multi-Year Plan (2018-2020), as shown in Appendix C: Revised Enbridge Budgets 2018-2020:

Table 2: Energy Leaders and Energy Literacy Budget Proposals (2018-2020)

	2018	**2019**	**2020**
Energy Leaders Initiative	$400,000	$400,000	$400,000
Energy Literacy Fund	$500,000	$500,000	$500,000

98. Pursuant to the recommendation made by the Company in its September 1st, 2017 Submission, and as mentioned in Section 5 above, the Company believes should the Board approve a 10% budget increase that it would be most appropriate to add 10% budget of the total annual program budget as a line item for the remainder of the Multi-Year Plan. The Company recommends that in practice, the 10% is annually derived from the total program budget and appears as a line item on the Company spreadsheet, entitled “Customer Incentive Fund.” Importantly, this 10% increase will not increase overheads. It only makes more funding available to meet customer incentives.

99. As mentioned in Section 5, the fund will only be used to support programs that require additional budget to fund the incentives owed to participants in efforts to reach higher targets. This fund will help to reduce the stress put on the incentive budget to stretch to meet higher targets, as there are no cost-efficiencies to be found in customer incentive payouts. This will also help ensure that the Company is not forced to borrow too much budget from one program at the expense of another and help the Company to manage its obligations while striving for maximum achievement.

100. The Company will calculate the Customer Incentive Fund from 10% of the total annual program budget, and will ring-fence the funds to only be spent on customer incentives should the existing approved budget of a program not be enough to support target. All budget enhancements can be found in Appendix C: Revised Enbridge Budgets 2018-2020.

Table 3: Proposed Annual Customer Incentive Fund

Year	2018	2019	2020
Total	$5.5M	$5.6M	$5.7M

Section 6: One Integrated Program with the IESO

101. Enbridge has successfully delivered its Home Energy Conservation (HEC) program, formerly called the Community Energy Retrofit (CER) since 2012. In 2012 the program had a few hundred customers, and by 2015 participation spiked to 5,500. The program was so successful in 2015 that it had to be shut down mid-way through the year due to oversubscription, causing the Company to run out of incentive dollars. The Company re-applied for this program as part of its Multi-Year DSM Plan and was approved with an enhanced program budget enabling the Company to regain momentum in the program until 2020.

102. The HEC program uses a holistic approach, offering prescriptive and custom measures for residential customers who fuel their home with natural gas. The program offers meaningful engagement with customers through energy audits and recommendations for retrofits and other measures to help improve the energy performance of the home. Participants see lower energy bills, reduced carbon emissions, and improved home comfort.

103. Since delivering the program in 2012, Enbridge has built capacity in the marketplace for energy auditors, contractors, and manufacturers. The Company has developed expertise, relationships and infrastructure with a wide ranging network of industry partners, equipment suppliers, HVAC contractors and market participants.

104. On June 10th, 2016 the Ministry of Energy released a directive to the IESO making modifications to the Conservation First Framework. The directive instructed that the "IESO shall, in consultation with Distributors, centrally design, fund and deliver… a province-wide whole home CDM pilot program for residential consumers ("Whole Home Pilot Program") [and that] "the IESO shall, where appropriate, deliver Centrally-Delivered Programs in coordination with natural gas distributors."

105. In the fall of 2016, the IESO engaged Enbridge and together the two entered into negotiations to coordinate a province-wide delivery for a whole home pilot (WHP) program offering residential consumers options in a one-step application for gas and electric savings.

106. The objective is that the IESO would leverage Enbridge's existing HEC infrastructure to deliver the program, and layer on electricity measures into the

existing suite of prescriptive and custom gas measures. The WHP program would be delivered on the back of the current HEC program leveraging Enbridge's current energy auditors and sales team, marketing plans, tracking and reporting, and customer relationships. The pilot launch date was scheduled for Q2 2017 and contemplated operating until the first of either 8,000 participants enrolled or December 31st 2017. The program was so successful however, that the program has been extended to June 30th, 2018.

107. The pilot responds to customer demands of creating a simple one-stop shop with one program in the market that coordinates both electric and gas savings. This gives the customer greater choice and flexibility to choose the measure mix right for their home and budget. The pilot includes a single point of intake and assessment conducted by Enbridge's existing energy auditors. Customers are offered a variety of gas or electric measures eligible for incentives, and the customer receives a single rebate cheque for both gas and electric savings.

108. For customers to have access to the electric incentives offered through the WHP, they must first qualify for HEC by completing a pre- and post-audit, installing two measures and reach an annual fuel savings of at least 15% as part of the standard qualification process for HEC. Participants will not have access to the electric incentives unless they are abiding by HEC eligibility criteria.

109. Home energy assessments are delivered by Service Organizations approved by Enbridge, and energy auditors receive additional training to capture the appropriate data points, educate the consumer on energy savings and identify eligible electric measures. Incentives for electricity measures available through the pilot will be in addition to the existing incentives currently available through the SaveONenergy Programs. The Heating and Cooling incentives available through SaveONenergy will also be offered in the WHP giving participants access to all available incentives

through one transaction. Electric incentive levels will stay consistent with what is offered through local electric LDC programming.

110. To make the pilot province-wide, homes outside of the Enbridge franchise area are serviced through Enbridge's current Transfer Payment Agreement (TPA) with the Ministry of Energy (MOE) for its Whole Home Retrofit Program (WHRP) as funded through the Ministries' Green Investment Fund (GIF). The WHRP, launched in November 2016, offers fuel-agnostic incentives to customers inside and outside of Enbridge franchise area. In other words, the program offers incentives to participants whose primary heating fuel is either oil, wood, or propane.

111. For participants with electricity as their primary heating source, they now have access to the HEC program, as well as the electric offering from the WHP with funding provided by the IESO. Together, the HEC DSM program, the WHRP funded by the MOE and the WHP funded by the IESO collectively support a province-wide program that delivers the Home Energy Conservation program. This ensures accessibility of incentives to homeowners who fuel their home with natural gas, oil, wood, propane and/or electricity; in other words, a fuel agnostic program.

112. Homes within Enbridge franchise area that are heated with natural gas receive gas incentives through the HEC program, and incentives for electric measures are offered through the WHP program. Homes fueled with natural gas outside of the Enbridge franchise area receive incentives for gas measures through the WHRP (GIF Funded) program, and incentives for electric measures are offered from both the WHRP and WHP.

113. Air-source heat pumps installed as a second core measure in the Home Energy Conservation Program are incented by the WHRP program (GIF Funded). Homes

outside of the Enbridge franchise areas whose primary heating fuel is propane, wood, or oil receive core electric and fuel-agnostic incentives through WHRP and optional electric incentives through WHP.

Optional Electric Incentives listed below:	
ENERGY STAR Fridge - $75	ENERGY STAR Freezer - $75
ENERGY STAR Dehumidifier - $30	ENERGY STAR Window Air Conditioner - $25
ENERGY STAR Washing Machine - $75	Upgraded Gas Furnace with ECM - $250
Upgraded Central-Air Conditioner with a CEE Tier 2 - $400	Various Incentive Amounts are also available for the installation of an Air-Source Heat Pumps (for electric-homes only) – up to $4,000

114. Homes within the Enbridge franchise area that do not have natural gas and are heated electrically have access to the incentives available through the HEC program and the optional electrical incentives offered in the WHP (as funded by the IESO). The IESO provides homes that are primarily electrically heated and wish to fully participate in the HEC program with the same incentives as would be provided gas customers should they fulfill the program requirements.

115. There is also an education piece when a customer calls their preferred Service Organization to book an energy audit or to learn more about HEC. When a customer calls the Service Organization, they are asked a series of questions to determine their pre-eligibility before an initial audit is booked with the homeowner (i.e. age of home, upgrades homeowner is considering, willingness to consider a second upgrade, etc.)

116. As mentioned above, Enbridge leveraged its current network of energy auditors to conduct home energy assessments and collect data. Enbridge also provided back-end process and issues payments for gas and electric incentives to customers. Enbridge is responsible to invoice the IESO for electric incentives paid. Enbridge provides customer support to participants through its existing customer service channels. Enbridge also undertakes tracking and reporting, sharing monthly tracking reports with the IESO.

117. Due to the inclusion of electric measures, there were modifications made to the current program administration process. The changes to the program materially increased workloads making the program a challenge for the Company's existing internal resources. The administrative process for manually inputting data, training employees, and implementing wholesale changes to the existing administrative processes taxed the Company's already limited resources.

118. This being said, the pilot program offered an opportunity for cost-sharing and alleviated some program costs from the Company's current program budget allowing the Company to stretch program dollars further to achieve more results. The IESO contributed program start-up costs to help support program management, marketing, administrative costs, training employees, training Service Organizations, etc. and provide on-going financial support for monthly reporting

needs, EMV, etc. The IESO covers the full-cost of marketing materials targeted to electrically heated homes.

Section 8: Integrated Resource Planning

119. During the EB-2012-0451 proceeding which involved the GTA Reinforcement Project, aspects of Integrated Resource Planning ("IRP") and the role of DSM in infrastructure planning were raised. In its Decision the Board found that:

> In light of the evidence presented, the Board concludes that further examination of integrated resource planning for gas utilities is warranted. … this review is particularly timely given the recent provincial Long Term Energy plan. Further information on how the Board will examine gas integrated resource planning will be released in due course[38].

120. In December 2013, the Minister of Energy issued a Long Term Energy Plan for Ontario, stating that: "The Ministry will also work with the Ontario Energy Board (OEB) to incorporate the policy of Conservation first into distributor planning processes for both electricity and natural gas utilities[39]".

121. The Minister's Directive to the Board in March 2014 with respect to the DSM Guidelines indicated that:

> By January 1, 2015, the Board shall have considered and taken such steps as considered appropriate by the Board towards implementing the Government's policy of putting conservation first in Distributor and Gas Distributor infrastructure planning processes at the regional and local levels, where cost-effective and consistent with maintaining appropriate levels of reliability[40].

122. The 2015-2020 DSM Framework issued by the Board on December 22, 2014 directs the gas utilities to each conduct a study no later than in time to inform the mid-term review of the 2015-2020 DSM Framework[41].

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[38] EB-2012-0451 Decision, January 30, 2014, pp. 46/47
[39] Ontario Ministry of Energy, Long Term Energy Plan, p. 4
[40] Minister's Directive to the Ontario Energy Board, 467/2014, March 26, 2014, s. 5, p. 3
[41] EB-2014-0134 Report of the Board: Demand Side Framework for Natural Gas Distributors (2015- 2020), p. 36

123. The Framework further required the utilities to file, as part of their 2015-2020 Multi-Year DSM Plan, a document which included a preliminary scope of the study it planned to conduct and a preliminary transition plan that outlined how the gas utility planned to include DSM as part of its future infrastructure planning efforts[42].

124. In response to these requirements, Enbridge included a Draft outline of the scope for the IRP Study which included the approach and method that Enbridge would undertake. This draft scope of work was included as EB-2015-0049 Exhibit C, Tab 1, Schedule 3.

125. In the Board's Decision it was further acknowledged that: "As indicated in the DSM framework, it is appropriate that the gas utilities study and submit a methodology for assessing the appropriate role for DSM as part infrastructure planning at the mid-term DSM review[43]."

126. During the course of the EB-2015-0049 DSM Multi-Year Plan proceeding and in the final decision of the Board, the Board's consultant "Synapse", Intervenors and expert witnesses suggested enhancements to the Enbridge study proposal, Enbridge included those enhancements in the final scope of work.

127. Additionally on June 22, 2016 there was a circulation of the final revised Integrated Resource Planning Study scope of work to the DSM Consultative prior to the release of the RFP. The Utilities further requested feedback from the DSM Consultative on the selection criteria to be used during the procurement and selection process.

[42] EB-2014-0134, Report of the Board: Demand Side Framework for Natural Gas Distributors (2015- 2020), p. 36
[43] EB-2015-0029 / EB-2015-0049, Decision and Order, January 20, 2016, p. 83

128. The correspondence indicated that the Utilities would be awarding the IRP Study contract based on the following criteria:

- Pricing: Competitiveness of rates
- Efficiency: Efficient delivery of services, ability to meet the schedule outlined in Scope of Services,
- Experience: Past experience with similar engagements, Regulatory experience, Composition of project team
- Meeting overall project requirements: As outlined in the Scope of Work

129. The Utilities received feedback from three intervenor groups on the selection criteria that would be used during the procurement process. Two of the respondents indicated that there should be a requirement to have Distribution planning experience in the selection criteria. This requirement was subsequently included. Another comment was to ensure that the study look at the relationship between DSM and Peak hour savings. This recommendation was already part of the study scope of work.

130. In the EB-2015-0049 Decision the Board instructed the utilities to have prepared a transition plan in time for the mid-term review:

> The OEB recognizes the challenge that it has given the gas utilities, to avoid new build by implementing selectively targeted DSM….The OEB directs 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[44].

131. The Board, in a letter dated June 20, 2017 regarding the DSM Mid-Term Review provided additional direction to the Utilities indicating that Union and Enbridge are

[44] EB-2015-0029 / EB-2015-0049, Decision and Order, January 20, 201, p. 84

"to submit a transition plan to incorporate DSM into infrastructure planning activities[45]" by January 15, 2018.

132. Enbridge appreciates the opportunities from a due diligence and continuous improvement model, as well as recognizing that there are many benefits and process alignments that will result from both the review and integration of the DSM and infrastructure planning processes. This implementation will be phased in over a period of time and informed by the outcomes of the Integrated Resource Planning study. As well, the ongoing in-field case study will include the installation of advanced meter reading capabilities that will help to ensure the accuracy and granularity of customer usage and peak hour savings necessary to inform and advise future infrastructure planning discussions. Future infrastructure planning discussions that include not only DSM opportunities but also perhaps behind-the-meter solutions may be enabled from installation of Automatic Meter Readers (AMR) thereby providing an inherent value not currently identified in the traditional feasibility analysis. More detail on the process phases and timeline is outlined in Appendix E: Integrated Resource Planning: Transition Plan.

133. Also attached as Appendix D is an Executive Summary of the IRP Study. This Executive Summary provides a summarization of the outcomes of the IRP Study and includes an overview of the:

- Review of Industry Experience;
- Natural Gas Facility Planning;
- Differences between Facilities and DSM Planning Criteria and Approach;
- DSM Impacts on Peak Day and Peak Hour Demand;
- Potential Impacts of DSM on Facilities Requirements ;
- Policy considerations;

[45] OEB letter dated June 20, 2017, Re: DSM Mid-Term Review (EB2017-0127 and EB-2017-0128) page 4

- Conclusions and recommendations.

Section 8: Demand Side Management Participant Incentive Deferral Account

134. In the Company's Multi-Year Application the Company proposed a Demand Side Management Participant Incentive Deferral Account (DSMPIDA) that would be used to record the variance between the approved budget in one year and the future incentive payments forecasted for those participants that enrolled[46]. This deferral account would allow the Company to best manage the budget for programs with multi-year incentive payouts and ensure the Company does not have to shut down programs prematurely.

135. In the Savings by Design (SBD) Residential program the builders that participate in the program have up to three years to build the homes and qualify for incentives. Incentives are only available to builders that can demonstrate the homes were built to the eligibility standards of the program. The SBD Commercial program is very similar, except builders have up to five years to claim incentives for the projects that meet the programs criteria. New to the Multi-Year DSM Plan, was the introduction of the Low Income New Construction program that also offers incentives to builders in the low income new construction housing market upon completion of the project.

136. The issue with the current means of accounting for these incentives is that while the program in the original year that the participant enrolled included in its budget all of the future potential incentives payable to that participate over the subsequent two to four years (i.e. the year of enrollment and the subsequent years for which they can qualify for an incentive) there is no mechanism to roll over the amounts

[46] EB-2015-0049 Enbridge Gas Distribution Inc., Argument in Chief, pg. 33

unpaid in year one and subsequent years into the year in which the incentive is paid out.

137. These unpaid incentives are being recorded as underspent on the program. This is inappropriate in that the obligations to pay incentives remain and the budgeted amounts were approved by the Board to satisfy these incentive payments. Under the current situation, Enbridge must either direct monies otherwise payable to future participants in subsequent years to the earlier enrolled participants who earn incentives in the year in question or direct monies from other programs to satisfy the incentives payable.

138. It should be recognized that the use of the DSMVA may not be appropriate as an alternative given its methodology. As well, Enbridge is of the view that use of the DSMVA is intended for promoting successful programs in a specific year not for substituting current year monies for formally approved budgets which were not used simply because not all approved costs were incurred in a particular year of a multi-year program.

139. As a result, it is self-evident that programs which are structured with multi-year incentive payout schedules are very challenging to manage as the budgeted amounts for incentives for a participant that qualifies in one year must be carried forward to when the incentive is actually claimed. Currently, the Company has no such mechanism to carry forward budget to ensure that funds are available to participants when they are ready to claim it. This is deeply troubling, in particular towards the end of the 5 year plan, as the Company does not have an approved budget post-2020 to fulfill its obligations to participants. Without a remedy, the Company must consider turning away participants towards the end of the Plan, as there is no account to hold funds for future payments.

140. Throughout the Multi-Year Regulatory Hearing, several intervenors inquired about the DSMPIDA and how it would operate; however none rejected its value, nor did any question its necessity. The only intervenor to comment was Energy Probe in its Final Argument which expressed concern that the out of period costs are being put into rates, especially given the changes to the Residential Savings by Design Program[47]. The response to this is simple. The proposed DSMPIDA does not put out of period costs into rates. It merely insures that budgeted costs approved by the Board are recorded in the year they are incurred.

141. The Company believes that it may be helpful if the methodology for the DSMPIDA was communicated more clearly so that intervenors and the Board would understand that no additional costs would be incurred by ratepayers due to the multi-year nature of the incentive payouts. In the deferral account, at the beginning of a program year the account would be credited the approved program budget collected from ratepayers for that program year. Some costs would be incurred that year from the program and would be spent appropriately. However, based on the number of participants that enroll in the program a certain amount of budget is forecasted to be used for future incentives. This amount would be held within the account, carried forward, and paid at a future date when the participant claims the incentive. The account will also be debited in that year for any payouts required from Year 1 participants who are ready to claim their earned incentives. The balance at the end of the year will be the amount forecasted to pay participants over several years, to be carried forward.

142. Currently, this mechanism does not exist. What does exist is a substantial rolling debt of potentially millions owed to participants that is growing every year the Company offers the programs. The Company requires either this deferral account

[47] EB-2015-0029, Final Submission Energy Probe Foundation, October 2, 2015, p. 35

or some other suitable mechanism to pay the funds required to meet its obligations to participants, and ensure the reputation and trust in the Company's successful DSM programming is not jeopardized. The alternative is that the Company will be forced to turn participants away or would require funds from future DSM plans post 2020, which are not currently approved. This is not to the benefit of ratepayers and participants.

143. For many years, Enbridge has offered two very successful, award winning SBD program streams: Residential and Commercial. They are well known within the industry and have contributed to the strong reputation and brand of Enbridge Gas Distribution in the energy efficiency world. As the utilities near the end of the Multi-Year Plan, a snowball of debt is accumulating and will become due. The Company does not want to jeopardize the success of this program, the programs reputation or the Company's trusted expertise, by not meeting its commitments. The Company has offered the SBD programs for many years, and has therefore accumulated potential large incentive payment obligations. Without this deferral account the Company has little to no recourse to correct this accounting challenge.

144. The Company is proposing that one DSMPIDA account be opened, with a subaccount for each program with a multi-year payout schedule. This will ensure that the approved program budget collected from ratepayers is held in the account and remains there until the participant has met the eligibility of the program and claims the incentive. All funds collected at the start of the program but not needed to pay incentives either in the current year or forecasted for future years, will be returned to the ratepayer at the annual Clearance of Accounts proceeding. Up to 30% of approved program budgets may be moved among programs, however the forecasted incentive amounts will be held in the account, not subject to budget

mobility as these funds are reserved for those participants[48]. The Company further requests, that the Board provide special approval to allow this account to remain open past the Multi-Year Plan to 2025 to ensure that the Company does not have to shut the programs down early and turn participants away from successful DSM programming.

Table 4 – Estimated Outstanding Participant Incentive Amounts for Programs with Multi-Year Payouts

Estimated Outstanding Participant Incentive Deferral Amounts at 100% Achievement (2020-2025)					
Program	**2021**	**2022**	**2023**	**2024**	**2025**
LINC	$ 1,475,000	$ 1,327,500	$ 885,000	n/a	n/a
Com. SBD	$ 1,290,000	$ 1,080,000	$ 660,000	$ 720,000	$ 750,000
Res. SBD	$ 2,500,000	$ 2,600,000	$ 2,900,000	n/a	n/a
Total	$ 5,265,000	$ 5,007,500	$ 4,445,000	$ 720,000	$ 750,000

1. Amounts calculated using pre-audited 2016/2017 actual achievement and targets as filed in Appendix A: Revised Enbridge Scorecards and Targets 2018-2020.
2. All programs assume participants claimed highest incentive available, as per Enbridge DSM Multi-Year Plan (2015-2020), EB-2015-0049
3. LINC participants assumed as part 3 and to have claimed incentive in three years.
4. Commercial Savings by Design participants assumed to have claimed incentives in five years.
5. Residential Savings by Design participants assumed to have claimed incentives in three years.

[48] EB-2014-0134, Filing Guidelines to the Demand Side Management Framework for Natural Gas Distributors (2015-2020), p. 14-15

Table 5 – Estimated Outstanding Participant Incentive Amounts for Programs with Multi-Year Payouts

Estimated Outstanding Participant Incentive Deferral Amounts at 150% Achievement (2020-2025)					
Program	**2021**	**2022**	**2023**	**2024**	**2025**
LINC	$ 2,212,500	$ 1,991,250	$ 1,327,500	n/a	n/a
Com. SBD	$ 1,290,000	$ 1,080,000	$ 990,000	$ 1,080,000	$ 1,125,000
Res. SBD	$ 3,750,000	$ 3,900,000	$ 4,350,000	n/a	n/a
Total	$ 7,252,500	$ 6,971,250	$ 6,667,500	$ 1,080,000	$ 1,125,000

1. Amounts calculated using pre-audited 2016/2017 actual achievement and targets as filed in Appendix A: Revised Enbridge Scorecards and Targets 2018-2020.
2. All programs assume participants claimed highest incentive available, as per Enbridge DSM Multi-Year Plan (2015-2020), EB-2015-0049
3. LINC participants assumed as part 3 and to have claimed incentive in three years.
4. Commercial Savings by Design participants assumed to have claimed incentives in five years.
5. Residential Savings by Design participants assumed to have claimed incentives in three years.

Section 9: Updates to Select DSM Program Offers for Board Consideration

Section 9.1: Home Energy Conservation

145. Enbridge is proposing enhancements to the Home Energy Conservation (HEC) program offer to drive increased participation and ultimately greater natural gas savings, by aligning the current HEC eligibility and incentive structure with the Union Gas Home Reno Rebate (HRR) program offer. Borrowing the Board's characterization, Union's approach to the HRR program is "more savings per customer" versus Enbridge HEC program offer is "savings over a larger group of customer.[49]" Both methods were approved by the Board in its Decision; however, Enbridge is proposing to modify its program to align with the HRR program to provide greater continuity across the province for the benefit of ratepayers.

[49] EB-2015-0049, Decision and Order, January 20th, 2016, p.13

146. The HEC program offer filed as part of the 2015 - 2020 DSM Framework outlined an incentive structure that was based on natural gas savings from the implementation of energy conservation measures (ECM) and the cost of pre and post energy audits[50]. Incentives were based on the following tiered incentive structure:

- Up to $500 for pre and post energy audits, not including HST
- $500 for achieving 15-25% annual natural gas savings that is incremental to $500 for the energy audits
- $1,100 for achieving 26-49% annual natural gas savings that is incremental to the $500 for the energy audits
- $1,600 for achieving 50% and above annual natural gas savings that is incremental to $500 for the energy audits

147. As the offer was delivered, the following key issues were identified:

- Created uncertainty for customers - that is, they did not know with certainty the monetary value of the final incentive they would receive until the post audit was completed.
- Uncertainty with potential customers that they may not achieve the performance threshold - as a result, some decided against participation.
- Difficultly with marketing and selling this approach - was viewed as too complicated by some customers.

148. As a result of the issues identified, the program offer was modified in early 2017 to adopt a single incentive structure of $1,600 per participant (inclusive of the $500 audit rebate) with the intention of addressing the barriers outlined above. This

[50] Enbridge Gas Distribution Inc. (the “Company” or “Enbridge”) Ontario Energy Board (the “Board”) File: EB-2015-0049 Multi-Year Demand Side Management Plan (2015 to 2020), Exhibit B, Tab 2, Schedule 1, pg. 25

change was designed to drive more participation and ultimately greater natural gas savings. Incentives continued to be paid based on pre and post home energy audits that input into NRCan's Hot2000 home modeling software to calculate natural gas savings[51]. Despite the change to a simplified single incentive structure, there continued to be feedback from customers regarding uncertainty in qualifying for the incentive.

149. As a result, Enbridge is proposing further enhancements to the HEC program offer to drive increased participation and ultimately greater natural gas savings – and therefore provide continuity for gas customers across the franchise territory. Specifically, the proposed enhancements will provide prescriptive incentives for each individual measure installed (minimum of two required) versus the current HEC program offer that provides a single performance based incentive, as outlined above.

150. Pre and post home energy audits will continue to be required to measure the HEC program's natural gas savings performance, but not in the determination of incentives paid to customers. With the enhancements to the HEC program, the offer continues to be cost-effective in compliance with the DSM Framework.

151. As described in Section 6, the Company is collaborating with the IESO to deliver the Whole Home Pilot Program (WHP)[52]. This provides a single point of contact for customers to access to both electric CDM and natural gas DSM measures - providing a seamless customer experience and maximizes energy savings. This approach is expected to attract more customers that may not otherwise participate in both programs and as a result capture more CDM and DSM savings. In addition,

[51] http://www.nrcan.gc.ca/energy/efficiency/housing/home-improvements/17725
[52] http://ieso.ca/en/sector-participants/ieso-news/2017/06/whole-home-pilot-program-launch

this approach minimizes the time and inconvenience for customers that want to participant in both programs - versus the alternative of having to deal with two organizations at different times. This collaborative approach is consistent with the DSM Framework and Ontario Long Term Energy Plan.

152. The current conservation frameworks encourage electricity and natural gas distributors to collaborate in providing more efficient programs and a streamlined experience for customers. Such partnerships can offer energy consumers a coordinated, one-window approach to help meet their energy management needs[53].

153. As also described in Section 6, in February 2016, the Ontario Government announced the allocation of $100 million from the Green Investment Fund (GIF) toward helping homeowners reduce their energy bills and cut greenhouse gas emissions[54]. In partnership with Enbridge and Union Gas, this effort was to influence about 37,000 homeowners conduct audits to identify energy savings opportunities and complete energy efficiency retrofits. In 2016, Enbridge and the Province signed an agreement for the establishment of $58 million of this funding toward the expansion of the Company's HEC and Adaptive Thermostat offerings and the introduction of a behavioural initiative. This expanded initiative is designed to leverage the infrastructure of the DSM HEC program offer already in place - which is in the best interests of the Province and aligned with its GHG reduction goals.

154. Beyond the reach of Enbridge's HEC DSM offer, GIF funding is targeting an additional 25,000 residential homeowners over the three-year term of the

[53] Ontario Long Term Energy Plan: Delivering Fairness and Choice, p. 95
[54] https://www.ontario.ca/page/green-investment-fund

agreement. Specifically, GIF funding will drive incremental uptake of natural gas customers beyond what would have been achieved with DSM HEC funding alone and fully attributable to GIF. In addition, GIF funding will extend the market for this program to include homes with a primary heating fuel that is non-gas (oil, propane or wood), as well as to homes outside of the Company's franchise territory; these participants and results will be fully attributable to GIF. The HEC program offer is a seamless customer experience.

155. The Company is communicating with the IESO and GreenOn with the goal to find solutions so that all program offers including Enbridge's are designed and delivered in a more collaborative manner across the Province. These issues are further discussed in the Section 10.

Section 9.2: Savings by Design Program Enhancements

156. In the evidence that follows, the Company provides an overview of the important benefits of both the Residential and Commercial Savings by Design programs. It should be noted that the importance of these programs will only become more evident with the enhancements that are proposed to both programs that will build on the value these programs offer. This further supports the company's position on providing an appropriate weighting for MTEM programs.

Savings By Design - Residential

157. The rapidly changing energy landscape and ever stringent building code changes require Enbridge to be responsive to the marketplace and customer needs. To this end, Enbridge is planning to make value added enhancements to the Residential Savings by Design (SBD) program. These enhancements build on the success of the initial program and the solid results that have been accomplished since inception.

158. Working with builders to develop the capabilities to build new homes more energy efficiently than required by the Ontario Building Code (OBC) is an important initiative. Through the Integrated Design Process ("IDP", or "design charrette"), builders learn about new technologies and advanced construction techniques and the importance of looking at energy efficiency from a holistic viewpoint.

159. This approach to energy efficiency becomes part of their long-term thinking rather than a conventional mindset to simply build homes to code. Often, builders learn that energy efficiency can be done more cost effectively than originally thought. For example, implementing higher efficiency building envelope measures results in smaller heating and cooling system requirements - with the resulting savings to capital, future energy costs and GHG emissions.

160. This process of change involves the entire building community value chain, including builders, architects, suppliers, contractors and trades as they collectively learn how to build more energy efficient homes as a united value chain, rather than as isolated players. The industry transformation from this program helps pave the way for future changes to building practices, partnerships and the building code.

161. When the Residential SBD program was first introduced the objective was to build homes to a minimum of 25% energy efficiency better than the 2012 building code. The January 2017 code change (Supplementary Standard SB-12 "Energy Efficiency for Housing" Amended on July 7, 2016) resulted in a minimum energy efficiency improvement of 15% over the previous code[55]. Therefore a 10% increase over the new 2017 building code is roughly equivalent to the previous 25% better than 2012 code. The enhanced program will support building homes

[55] http://www.mah.gov.on.ca/Page15251.aspx

10% better than the new 2017 code; but will also encourage and advance additional deeper savings through higher incentives for homes built to 15% and 20% better than the 2017 Ontario building code.

162. Under the enhanced program the Company will provide builders with an IDP, in addition to an incentive for homes built to a minimum 10% better than code; but will discontinue the option for builders to attend a 2nd and 3rd IDP to be eligible for incentives for homes built to a minimum 10% better than code (previously 25% better than the 2012 code). The enhanced program will instead provide motivation to eligible builders to attend a 2nd and 3rd IDP and receive individual home incentives that targets deeper savings of 15% and 20% better than the new 2017 code. This new approach is designed to move builders to progressively higher levels of energy efficiency as they proceed through the IDPs.

163. The focus of the original program was to target the largest builders to generate the highest number of new homes - and this continues to be an effective strategy. The enhanced program is designed to broaden the reach beyond large production builders and to also transform the capabilities of small/custom and mid-sized builders.

164. Given the number of medium and small/custom builders anticipated to participate, the Company will begin offering charrettes with multiple builders in attendance. For example, a targeted charrette may be held for a medium townhome built to 10% better than code or a medium detached home built to 15% better than code and so on. Having multiple builders in attendance will control program costs to better align with a lower number of homes per builder and potential aggregate energy savings for this market segment. Where competitiveness and confidentiality are an issue, the Company will continue to offer exclusive IDP for builders.

165. The enhanced program will also expand capabilities development beyond the up-front design phase to include the construction phase and provide more targeted support - which is more aligned with the approach used in the Union Gas Optimum Homes program.

Savings by Design - Commercial

166. The rapidly changing energy landscape and ever stringent building code changes, will impact the commercial sector in a similar way to the residential sector that requires Enbridge be responsive to the marketplace and customer needs. To this end, Enbridge is also making positive changes to the Commercial Savings by Design (SBD) program. These enhancements build on the success of the program to date and the strong results that have been accomplished to date.

167. The original objective of the Commercial SBD program was to design and construct commercial buildings to an energy efficiency of 25% better than the 2012 Ontario Building code. With the recent 2017 code changes, the program was modified to require a minimum energy savings of 15%.

168. The SBD program has provided important ancillary benefits to municipalities, property owners and building managers. Feedback has confirmed the program not only assists with enhancing the energy efficiency of a specific building development under review, but also provides valuable input into the long term energy planning needs for both existing and future building stock. This provides important value to these organizations to help them meet 2030 and 2050 provincial GHG reduction goals.

169. Building on this customer need, the Company is planning to expand the program offering to provide additional focus on long term energy efficiency planning for future developments and existing building stock. These enhancements are strongly aligned with the provinces GHG reduction targets and consistent with the market transformation objectives of this program.

170. These programs provide important market transformational benefits to a market segment that can have a meaningful impact on energy savings for decades. The positive benefits of these programs help support the rationale for a scorecard weighting that appropriately values the remaining MTEM programs. The Company's overarching objective is to maximize benefits for ratepayers when shareholders and ratepayer benefits are aligned. This will ensure both parties benefit from high performing MTEM programs.

Section 10: Collaboration with Electric Utilities and Others

171. On March 31, 2014 the Minister of Energy released its 2015-2020 Conservation First Framework Directive to the Independent Electricity System Operator (IESO) that included a requirement for "Distributors, where appropriate, to coordinate and integrate Province-Wide Distributor CDM Programs and Local Distributor CDM Programs with natural gas distributor ('Gas Distributors') conservation programs to achieve efficiencies and convenient integrated programs for electricity and gas customers[56]".

172. On December 22, 2014, the Board included in its DSM Multi-Year Framework (2015-2020) requirement that the gas utilities and electric distributors should pursue coordination and integration in key program areas in pursuit of

[56] http://powerauthority.on.ca/sites/default/files/news/MC-2014-856.pdf

programming for shared customers. The Board noted this coordination would typically occur during the design phase of a program to ensure consistency in the delivery of services of a given program.

173. In Enbridge's Multi-Year DSM Plan (2015-2020) ('the Plan"), the Company highlighted its current involvement in discussions with electric LDC's for collaborative CDM programs and pilots. The Plan also noted the Company's areas of focus to coordinate and integrate with LDC CDM activities throughout the 6-year term. Due to the timing of the submission of the Plan, the Company was unable to meet with LDC's prior to filing, to develop net new collaborative programs, or redesign existing programming to achieve greater integration. Enbridge noted that for various reasons such as process compatibility, legal contracting etc., that program integration would take time to achieve.

174. To demonstrate its commitment to pursue enhanced coordination over the course of the Plan, the Company applied for a Collaboration and Innovation Fund (CIF) to support the additional costs of launching pilot programs to integrate existing programming.

175. In the Board's Decision and Order dated, January 20th, 2016 ("the Decision") the Board approved the CIF recognizing the need for additional funding for collaborative initiatives and to integrate programming. The Board encouraged the Company to pursue greater coordination and integration of CDM and DSM programing.

176. On June 10th, 2016 the Minister of Energy released a directive to the IESO, directing it to: "in consultation with Distributors, centrally design, fund and deliver…A province-wide whole home CDM pilot program for residential consumers ("Whole Home Pilot Program")". The directive further stated that the

"IESO shall, where appropriate, deliver Centrally-Delivered Programs in coordination with natural gas distributors[57]."

177. On November 21st, 2016 at the IESO led working group "Conservation First Implementation Committee ("CFIC"), the IESO presented the Residential Portfolio Roadmap: Recommendations for the Working Group prepared by Navigant Consulting Ltd for electric LDC's and observing gas utilities[58]. Navigant was retained by the IESO to evaluate the current landscape of residential energy efficiency programs and trends within Ontario, and to provide a set of recommendations based on current market opportunities for electric LDC's to pursue. Navigant recommended that with the expansion of the Whole Home pilot, as directed by the MOE, and with other opportunities for cross-fuel collaboration in the residential sector, that the electric utilities should spend about 30-40% of their effort towards collaboration with natural gas utilities.

178. The Conservation First Framework (2015-2020) and the Demand Side Management Framework (2015-2020) respectively call for enhanced integration and collaboration by electric and gas programming. With the addition of the CIF to pursue greater collaborative and innovative initiatives, the Company developed a Collaboration Strategy and established a dedicated resource to pursue and coordinate areas for collaboration throughout its Multi-Year Plan.

<u>Collaboration Strategy</u>

179. Enbridge developed a Collaboration Strategy that assesses and implements opportunities for collaboration with electricity distributors and other energy

[57] http://www.ieso.ca/Documents/Ministerial-Directives/20160610-Directive-LRPII-ConservationFramework-SupportPrograms.pdf
[58] Residential Portfolio Roadmap: Recommendations for the Working Group. Navigant Consulting Ltd. Nov 21, 2016

providers to create cost-effective, energy agnostic programming that allows consumers to benefit from one source of investment and assistance accelerates the adoption of energy efficiency initiatives in Ontario.

180. The Collaboration Strategy approaches collaboration of energy management programs in two phases. The first phase focuses on gaining traction with other utilities by opening up channels of communication to “piggy-back” on established programming. In this phase natural gas or electric measures are layered onto existing programming that would increase gas and electric savings for the collaborating utilities and provide the customer a single point of contact for dual savings.

181. In phase 2 Enbridge engaged with electric utilities to seek opportunities for net new programming that is innovative, creates cost-efficiencies and is easily accessible to customers. The next level of Enbridge’s broader collaboration strategy will be to develop net new fuel-agnostic programming with multiple or all Ontario energy utilities to be delivered province-wide.

182. To inform and direct the Collaboration Strategy the Company developed a set of Guiding Principles. All collaborative initiatives, actions, and decisions were first evaluated for their strategic fit within the 3 Guiding Principles: Financial Efficiency, Improved Customer Experience and Enhanced Business Process. The Collaboration Guiding Principles ensured that a spectrum of considerations was accounted for in decision-making.

183. To mobilize the Collaboration Strategy, Enbridge established a dedicated resource to lead the collaborative efforts between Enbridge, the IESO, LDC’s, GreenON and other key stakeholders that would drive CDM and DSM program participation and energy savings. The dedicated resource, the DSM Collaboration

Specialist, worked with internal and external stakeholders to identify strategic opportunities, supported internal resources to implement such opportunities, and developed an operating and guidance framework for the collaborative initiatives seeking funds from the CIF.

184. Part of the strategy was to seek opportunities for collaboration at the design phase of program development. In the Conservation First Framework (2015-2020), electric LDC's were given greater autonomy over the design of their programs with oversight and approval from the IESO, and hosted working groups to inform and collaborate on program ideas. The DSM Collaboration Specialist and other DSM Program Managers actively participated in the LDC working groups and was able to provide input into program design, delivery and implementation efforts to promote program uptake and enhance the customer experience through electric and gas collaboration. The LDC working groups included the Conservation First Implementation Committee ("CFIC"), the Residential Working Group, the Business Working Group, the Sales and Marketing Working Group, and the Data and Evaluation Working Group.

185. At these working groups, Enbridge has taken the opportunity to promote joint programming to realize cost efficiencies and improve customer experience. Working group meetings are also excellent forums for information sharing, lessons learned and idea generation for gas-electric collaboration at the program design stage.

186. Enbridge also works with the IESO on targeted training programs to help build the energy management capability of its customers and business partners, helping them identify opportunities in their facilities, optimize energy savings, and reduce carbon emissions, while maintaining sound operational, environmental and sustainable practices.

187. In early 2017, Enbridge, Hydro Ottawa and IESO delivered the first co-funded Selling Energy Efficiency sales training program for channel partners. The two-day training session was attended by HVAC contractors, energy management consultants, energy services and product providers. A majority of the participants were channel partners jointly invited by Enbridge and Hydro Ottawa. Participants were provided with skills to sell energy efficiency solutions that leverage on both gas and electricity programs. The feedback from participants was overwhelmingly positive. Enbridge intends to participate in similar training programs with the IESO that targets common regional business partners and advances mutual goals.

188. Enbridge is also collaborating with the IESO to provide financial incentives to customer participants of the Building Operators Certification Program. The program aims to equip building operators with the skills and knowledge to operate building mechanical systems efficiently. This program also complements the objectives of the RunitRight Program.

189. Internally, DSM Management encourages staff to constantly seek areas or opportunities for collaboration and program synergies during their daily course of business and interactions. Collaboration discussions are encouraged at team meetings and internal staff is urged to bring forward opportunities or ideas for exploration that could enhance DSM and CDM collaboration.

Collaboration and Innovation Fund

190. Guiding Principle #3 of the Board's Multi-Year DSM Framework establishes a priority for gas utilities to focus efforts towards greater collaboration and integration between CDM and DSM program offers. The Board set as a goal "where appropriate, coordinate and integrate DSM and electricity CDM efforts to achieve

efficiencies[59].” The Board reasoned that where DSM could be integrated, designed and promoted with CDM that both parties would experience greater overall efficiency, reduced delivery costs, and maximized results.

191. In 2015, the Company developed and prepared a suite of cost-effective DSM programming for the residential, commercial, industrial and low-income customer segments that would form part of Enbridge’s Multi-Year DSM Plan. The Company developed offers ranging from efficiency incentives, educational platforms, and technical advice, to new construction design seminars. During this time, there was a high volume of interested electric LDC’s looking to Enbridge for funds to contribute to various collaborative initiatives and pilot projects. The IESO, in its Conservation First Framework, prioritizes collaborative partnerships with gas utilities when approving LDC CDM Plans. As noted during the Multi-Year Plan Hearing, LDC’s were approaching Enbridge during the design phase of their programs, without final approval from the IESO therefore making it difficult for the two parties to go beyond discussions at this point in time.

192. To respond to LDC engagement and satisfy Board requirements to collaborate the Company knew that additional funds in excess of program budgets would be required to pursue a greater degree of collaboration. The Company also wanted to capitalize on the term length of the Multi-Year Plan and spend resources over time seeking and developing innovative ways to increase energy efficiency among customers.

193. As a solution, the Company applied for a Collaboration and Innovation Fund (“CIF”). The fund, as contemplated in 2015, would provide Enbridge with an

[59] EB-2014-0134, Demand Side Management Framework for Natural Gas Distributors (2015-2020), December 22, 2014, p.8

available budget, separate from program budgets, to pursue collaborative and innovative initiatives that would strengthen the Company's ability to respond to LDC' pilot proposals and other areas for collaboration while seeking innovative strategies that would position the Company to reach the next level of results and meet customer demands.

194. In the Board's Decision and Order ("the Decision") released January 20th, 2016, the Board approved the Company's proposed $6M Collaboration and Innovation Fund over the course of the Multi-Year Plan (2015-2020). The Fund provided the Company with the confidence and flexibility to access funds to explore opportunities for collaboration and innovation.

Collaboration and Innovation Fund Governance

195. To lead the Company's collaboration strategy and manage the Collaboration and Innovation Fund, Enbridge formed a Collaboration and Innovation Fund Steering Committee ("the CIF Steering Committee"). The CIF Steering Committee, comprised of 5 DSM Managers and the DSM Collaboration Specialist, meets bi-monthly to evaluate collaborative and innovative opportunities brought forward from internal program staff, a member of the CIF Committee, or other DSM management.

196. The Committee follows a set of "Collaboration and Innovation Steering Committee Guiding Principles" when reviewing opportunities for innovation or collaboration that are seeking financial support from the fund. The principles preserve the integrity of the fund by setting expectations and rules which the committee must follow when considering the use of the fund. The CIF Committee Guiding Principles include:

- All impacts and implications towards multi-year targets and budgets will be considered.
- Opportunities for collaboration are considered on a spectrum (e.g. cost savings, operational efficiencies, customer experience, marketing, technology and process innovation, integrated programming, etc.).
- Oversight and management of the CIF budget to maximize efficient and effective use.
- Pro-actively achieve collaborative results through leadership and innovation, supported by strong documentation.

197. When evaluating opportunities, the CIF Steering Committee adheres to the Collaboration and Innovation Fund Principles that define the objective of the fund and provide strategic direction for decision-making. All opportunities are evaluated and reviewed for their ability to produce at least one of the following Collaboration and Innovation Guiding Principles:

- Expands DSM business and abatement innovation
- Realizes DSM results and/or costs savings
- Brings value to customers
- Enhances business processes and program operations

198. An initiative or project that meets the first criteria, “expands DSM business and abatement innovation,” has achieved one of several potential outcomes ranging from exploring the inclusion of a new technology into traditional DSM programming, to developing a new and innovative partnership, to developing a program for province-wide delivery.

199. An initiative or project that meets the second criteria “realize DSM results and/or cost savings” has achieved one of several outcomes ranging from generating

higher gas savings, to finding cost-efficiencies, to enhancing the ability to produce positive outcomes on a scale that Enbridge could not achieve alone.

200. An initiative or project that meets the third criteria “brings value to customers” has achieved one of several outcomes ranging from improving the customer experience, to reducing market confusion, to promoting a holistic energy management approach.

201. An initiative or project that meets the fourth criteria “enhances business processes” has achieved one of several outcomes ranging from simplifying the process, to sharing responsibilities and costs with another utility, to offsetting program costs therefore enabling the Company to reach more participants.

202. An opportunity for collaboration or innovation must go through the application process before it reaches the CIF Steering Committee. An Initiative Owner is responsible for the identification, development, and project management of an initiative. The Initiative Owner first completes a CIF Application Form which captures the main details and essence of the initiative. The form requests that the applicant provide a brief summary of the initiative, the strategic fit and value of the initiative against the Guiding Principles, as well as applicable dates, contact information and the dollar amount requested of the CIF. The application is brought to the CIF Steering Committee by the DSM Collaboration Specialist for review and debate. A quorum of 3 votes is required for an initiative to advance to the next phase of development.

203. Once an initiative passes the CIF Steering Committee, the DSM Collaboration Specialist notifies the Initiative Owner, and together the Initiative Owner and the DSM Collaboration Specialist are jointly accountable to drive the collaborative outcomes and optimize the results. The applicable businesses cases and

contracts are developed together and taken through the regular procurement and legal channels as appropriate. The DSM Collaboration Specialist is responsible for tracking the amount of CIF funds expensed to the initiatives as approved by the CIF Steering Committee.

204. The CIF Steering Committee continues to meet bimonthly regardless if there are new opportunities to discuss. The DSM Collaboration Specialist keeps abreast of all initiatives that receive CIF funding, and provides updates on the CIF spend.

Table 6: Collaboration and Innovation Initiatives Summary[60]

Partner	Customer Segment/ Topic	Overview
IESO and Union Gas	Residential	On June 10, 2016 the Ministry of Energy directed the IESO to deliver a province-wide whole home CDM pilot in coordination with natural gas distributors[61]. Enbridge, Union Gas and the IESO partnered to deliver the Whole Home Pilot. Leveraging the program infrastructure of the Home Energy Conservation offer, the pilot offers a province wide delivery offering of both gas and electric savings.
Toronto Hydro	Residential	Enbridge collaborated with an electric LDC to deliver Enbridge's Adaptive Thermostats program. The dual-fuel savings generated by the technology makes it ideal to collaborate an integrated CDM and DSM program

[60] EB-2015-0245, Reporting of Enbridge Gas Distribution Inc.'s 2016 DSM Program Results, November 16th, 2017, p. 133 -136
[61] June 10th, 2016; Ministry of Energy Directive to the Independent Electricity System Operation, Re: Conservation First Framework.

Partner	Customer Segment/ Topic	Overview
		offer.
Toronto Hydro	Low Income	Enbridge and an electric LDC pursued a collaborative delivery model for two separate programs with similar customer eligibility criteria and administrative requirements. Through a joint procurement process, a single delivery agent for the two programs was identified, generating cost efficiencies for each utility and enhanced customer experience.
Multiple LDCs	Commercial	Enbridge participated in a regional electric LDC energy conservation information and networking event in the Greater Toronto Area. The event connected customers, industry partners and utilities and provided an opportunity to share industry trends and enhance knowledge sharing and networks. Enbridge participated to provide perspective and influence to a predominately electric conference for a more holistic energy understanding.
Multiple LDCs	Commercial	Enbridge participated in a regional electric LDC energy conservation information and networking event in the Hamilton/Niagara Area. The event connected customers, industry partners and utilities and provided an opportunity to share industry trends and enhance knowledge sharing and networks. Enbridge participated to provide perspective and influence to a predominately electric conference for a more holistic energy

Partner	Customer Segment/ Topic	Overview
		understanding
Multiple LDCs	Commercial	Enbridge partnered with the 13 electric LDCs representing the Greater Toronto Hamilton Area to form an 'Energy Sales Force.' The Energy Sales Force developed an online web portal for each utility to provide LDC/gas utility contact and program information, and to encourage leads and opportunity sharing between utilities. The web portal increased collaboration and knowledge sharing between utilities thus improving the efficiency of program delivery for both DSM and CDM program offerings.
PowerStream	Commercial	Enbridge and an electric LDC collaborated to create a co-branded DCKV campaign for the food service industry. DCKV is a dual savings technology.
Toronto Hydro	Commercial	Enbridge developed a Combined Heat and Power (CHP) Tool that screens CHP project viability. Enbridge partnered with an electric LDC to give it user rights over the tool. In exchange the LDC provides data and feedback to Enbridge to help refine the tool for accuracy and inform the Company's research on CHP gas savings.
Enersource	Commercial	Enbridge partnered with an electric LDC to deliver energy audits for small and medium Commercial and Industrial customers to identify energy efficiency opportunities for electric and gas savings.

Partner	Customer Segment/ Topic	Overview
Multiple Industry Partners	Combined Cooling and Heating technology	Multiple industry partners have collaborated to test and validate an in-field demonstration of the May Ruben Thermal Solutions (MRTS) Combined Heating and Cooling technology. Enbridge is looking to test modifications that may increase the overall efficiency of the natural gas components.
Multiple Industry Partners	Canmet ENERGY's Energy Efficiency Workshops	Natural gas utilities provide funding to deliver six workshops across Canada. Enbridge provided funding for the workshop in Ontario to showcase innovative natural gas heating equipment to Canadian homebuilders, including a 'Design Guide' that will demonstrate natural gas equipment for an energy efficient home.
Multiple Industry Partners	Combined Heat and Power	Enbridge is participating in a CHP consortium with a focus on debate and understanding of issues surrounding CHP technologies by a group of key and diverse industry stakeholders.
Alectra and City of Markham	Net Zero	EGD, City of Markham and Alectra have joined forces in a project titled "Moving Towards Net Zero Energy Emission (NZEE).

<u>Opportunities for Policy Led Collaboration</u>

205. In the Company's September 1st Submission, it highlighted for the Board the necessity of modernizing the DSM Framework as a response to the significant changes within government policy. Since the DSM Framework was released in

2014, the policy and regulatory environment in which the Company offers DSM has changed the way in with the Company's delivers DSM and carbon abatement. With the inception of Cap and Trade, and the establishment of the GreenON, the energy efficiency market has become flooded with new actors and funding resources. The Company believes that with these funding resources, that an opportunity to coordinate efforts and collaborate for the benefit of ratepayers.

206. For example, the Company launched its Adaptive Thermostats program offering customers a $100 on bill credit. In December of 2017, the GreenON launched its own Adaptive Thermostats program that also offers $100 in the form of a cheque. As described in Section 1, the customer experience could be improved by coordinating efforts and realizing efficiencies through collaboration.

207. The mandate of the GreenON, as described in the Climate Change Action Plan (CCAP), is to for example, finance low-carbon energy technologies, green technologies and retrofit deployments for the residential, commercial and industrial sectors. The CCAP forecasts that the Green House Gas Reduction Account (GGRA) will hold $1.8 to $1.9 billion annually for the 2016-2017 compliance period, to be distributed among a plethora of entities in the energy efficiency market in order to fulfill its mandate[62]. The Company believes that the CCAP is broad and could achieve deep and meaningful greenhouse gas reductions incremental to what is currently being done through DSM and CDM.

208. The Company has obligations through the Cap and Trade regime to manage the carbon emissions profile of its customers. Part of the Company's Compliance Plan is to abate carbon to offset the need to purchase allowances on the customer's

[62] How Cap and Trade Works, Government of Ontario, November 30th, 2016 https://news.ontario.ca/ene/en/2016/11/how-cap-and-trade-works-1.html

behalf. As the Company outlined in the September 1st, 2017 Submission, DSM is part of the Company's Compliance Plan to help customers abate carbon and save money on allowance purchases[63].

209. The Company believes that where there is overlap between the mandates of DSM, Cap and Trade, GreenON, and CDM that the ratepayers are best served through coordination and collaboration. The areas that do not overlap are then best served by the individual mandates that are best equipped to serve it. For example, DSM is governed by rigorous cost-effective protocols to which the GreenON is not subject. This allows GreenON to pursue the non-cost effective deep measures that the Company cannot pursue as it would fail the TRC calculation. GreenON is best equipped to serve these areas as it has a less stringent governance framework, and the funds available to achieve these expensive activities.

210. The Company believes that the most effective collaborative will be result when all three mandates coordinate their efforts to ensure there is minimal overlap by working together and incrementally to one another. To work together, a clear attribution policy for kilo watts, cubic meters, and greenhouse gases must be determined, enabling the three mandates to work in unison, offering the best programs for the best value for money. The energy sector is evolving, and the entities that once worked independently, or those who are simply new to the sector, must come together for the betterment of the ratepayer and the Province.

211. Where collaboration between DSM and GreenON, or other entities funding energy conservation programs not be achieved, and the new external program duplicates results in one or more of the Companies existing program offers, it no longer being beneficial to rate payers. The Company, therefore, requests that the

[63] EB-2017-0128, DSM Mid-Term Review, September 1, 2017, p.10

Board consider ad hoc proposals for reallocation of program budget and shareholder incentive from its existing scorecard to other Board approved scorecards. In circumstances where the Company is unable, despite best efforts, to reach a collaborative agreement, the Company would like the opportunity to present for the Board, via a proposal, revised scorecards outlining a reallocation of the budget and shareholder incentive to other DSM programs.

<u>Section 11: Summary of Requests</u>

212. The company appreciates the opportunity to provide input and comments and submits the evidence above, combined with the previous submissions on September 1st and October 2nd, 2017, to comply with the Board's requests for the Mid-Term Review of the 2015-2020 Demand Side Management Framework.

213. In addition to providing information on the Boards specific requirements, the evidence also proposes enhancements that modernize the DSM Framework and governance to fit this new policy era (i.e. CCAP, Cap and Trade). These enhancements will enable the Company to continue to run successful DSM programs as well as pursue meaningful collaboration with electric utilities and GreenON for the benefit of rate payers.

214. As indicated in the Sept 1st, 2017 Submission, the Company requests that these enhancements be effective for the 2018 DSM operational year, to ensure the improvements can be effective as quickly as possible[64].

215. To facilitate the Board's review, the table below itemizes the list of specific requests as detailed in the Companies September 1st, 2017, October 1st, 2017, and January 15th Mid-Term Submissions.

[64] EB-2017-0128, DSM Mid-Term Review Comments of Enbridge Gas Distribution, September 1st, 2017, p.31

Table 7: Summary of Enbridge Recommendations and Requests

Request/ Recommendation	Description	Submission Reference
Fixed Net to Gross Value	Utilize a fixed net to gross value for the remainder of the Multi-year term.	September 1st,2017, p.21 -24 January 15th, 2018, Section 5
10% Budget or Target Adjustment	Provide a 10% budget increase to program budgets or 10% target decrease	January 15th, 2018, Section 5
Modify Shareholder Incentive formula	Revise the incentive formula to align the benefits to rate payers and shareholders	September 1st,2017 , p.30-31
Exempt TAM for Programs with Deferred Incentives	For programs with deferred incentive payouts, use fixed targets with an appropriate escalation factor instead of the target Adjustment Mechanism (TAM)	January 15th, 2018, Section 5
Consistent Productivity Factor	Utilize a consistent productivity factor of 2% for all programs	January 15th, 2018, Section 5
Transfer RiR and CEM programs to RA	Move Run It Right (RiR) and Comprehensive Energy Management (CEM) programs from Market Transformation and RA and assign an appropriate weight	January 15th, 2018, Section 5 Appendix B: Revised 2018-2020 Metric Weighting
Changes to Scorecard Weighting	Change the scorecard weighting between the three programs to ensure Market Transformation programs continue to receive a high level of focus	January 15th, 2018, Section 5 Appendix A: Revised Enbridge Scorecards and Targets 2018-2020
Funding for Energy	Provide funding for Enbridge's	

Request/ Recommendation	Description	Submission Reference
Leaders and Energy Literacy	Energy Leaders and Energy Literacy funding for 2018-2020.	January 15th, 2018, Section 5
DSM Participant Incentive Deferral Account	Introduce a Participant Incentive Deferral Account to allow the company to properly fund programs with future incentive obligations.	January 15th, 2018, Section 6
Saving By Design	Change the threshold for customers to qualify for building incentives for Residential Savings by Design (SBD) to 10% above the new 2017 Ontario Building Code	January 15th, 2018, Section 9.2
Home Energy Conservation	To align with Union Gas Home Reno Rebate program to prescriptive incentive model	January 15th, 2018, Section 9.2

EGD OEB-Approved Scorecards

Enbridge 2018 Resource Acquisition Scorecard

Programs	Metrics	Metric Target			Weight
		Lower Band	Target	Upper Band	
Home Energy Conservation (HEC) Residential Adaptive Thermostats Commercial & Industrial Custom Commercial & Industrial Prescriptive Commercial & Industrial Direct Install Run-it-Right Comprehensive Energy Management (CEM) Energy Leaders	Large Volume Customers Cumulative Natural Gas Savings (m3)	75% of Target	2017 metric achievement (LRAM natural gas savings) / 2017 Large Volume Customers Resource Acquisition actual spend without overheads x 2018 Large Volume Customers Resource Acquisition budget without overheads x 1.02	150% of Target	35%
	Small Volume Customers Cumulative Natural Gas Savings (m3)	75% of Target	2017 metric achievement (LRAM natural gas savings) / 2017 Small Volume Customers Resource Acquisition actual spend without overheads x 2018 Small Volume Customers Resource Acquisition budget without overheads x 1.02	150% of Target	35%
Home Energy Conservation (HEC)	Residential Deep Savings Participants (Homes)	75% of Target	2017 metric achievement / 2017 actual program spend without overheads x 2018 program budget without overheads x 1.02	150% of Target	15%
Run-it-Right	Participants	83	111	167	7.5%
Comprehensive Energy Management (CEM)	Participants	8	11	17	7.5%

Note: Metric achievement is calculated using verified program savings used for LRAMVA purposes with fixed Net-to-Gross Factor

Enbridge 2018 Low Income Scorecard

Programs	Metrics	Metric Target			Weight
		Lower Band	Target	Upper Band	
Home Winterproofing	Cumulative Natural Gas Savings (m3)	75% of Target	2017 metric achievement (LRAM natural gas savings) / 2017 actual program spend without overheads x 2018 program budget without overheads x 1.02	150% of Target	45%
Low-Income Multi-Residential	Cumulative Natural Gas Savings (m3)	75% of Target	2017 metric achievement (LRAM natural gas savings) / 2017 actual program spend without overheads x 2018 program budget without overheads x 1.02	150% of Target	45%
Low-Income New Construction	Participants	8	10	15	10%

Note: Metric achievement is calculated using verified program savings used for LRAMVA purposes

Enbridge 2018 Market Transformation & Energy Management Scorecard

Programs	Metrics	Metric Target			Weight
		Lower Band	Target	Upper Band	
School Energy Competition	Schools	59	79	118	20%
Residential Savings by Design	Builders	19	25	37	20%
	Homes Built	1,931	2,575	3,862	20%
Commercial Savings by Design	New Developments	17	22	34	40%

Enbridge 2019 Resource Acquisition Scorecard

Programs	Metrics	Metric Target			Weight
		Lower Band	Target	Upper Band	
Home Energy Conservation (HEC) Residential Adaptive Thermostats Commercial & Industrial Custom Commercial & Industrial Prescriptive Commercial & Industrial Direct Install Run-it-Right Comprehensive Energy Management (CEM) Energy Leaders	Large Volume Customers Cumulative Natural Gas Savings (m3)	75% of Target	2018 metric achievement (LRAM natural gas savings) / 2018 Large Volume Customers Resource Acquisition actual spend without overheads x 2019 Large Volume Customers Resource Acquisition budget without overheads x 1.02	150% of Target	35%
	Small Volume Customers Cumulative Natural Gas Savings (m3)	75% of Target	2018 metric achievement (LRAM natural gas savings) / 2018 Small Volume Customers Resource Acquisition actual spend without overheads x 2019 Small Volume Customers Resource Acquisition budget without overheads x 1.02	150% of Target	35%
Home Energy Conservation (HEC)	Residential Deep Savings Participants (Homes)	75% of Target	2018 metric achievement / 2018 actual program spend without overheads x 2019 program budget without overheads x 1.02	150% of Target	15%
Run-it-Right	Participants	98	130	196	7.5%
Comprehensive Energy Management (CEM)	Participants	9	11	17	7.5%

Note: Metric achievement is calculated using verified program savings used for LRAMVA purposes with fixed Net-to-Gross Factor

Enbridge 2019 Low Income Scorecard

Programs	Metrics	Metric Target			Weight
		Lower Band	Target	Upper Band	
Home Winterproofing	Cumulative Natural Gas Savings (m3)	75% of Target	2018 metric achievement (LRAM natural gas savings) / 2018 actual program spend without overheads x 2019 program budget without overheads x 1.02	150% of Target	45%
Low-Income Multi-Residential	Cumulative Natural Gas Savings (m3)	75% of Target	2018 metric achievement (LRAM natural gas savings) / 2018 actual program spend without overheads x 2019 program budget without overheads x 1.02	150% of Target	45%
Low-Income New Construction	Participants	7	9	14	10%

Note: Metric achievement is calculated using verified program savings used for LRAMVA purposes

Enbridge 2019 Market Transformation & Energy Management Scorecard

Programs	Metrics	Metric Target			Weight
		Lower Band	Target	Upper Band	
School Energy Competition	Schools	69	92	137	20%
Residential Savings by Design	Builders	20	26	39	p
	Homes Built	2,009	2,679	4,019	20%
Commercial Savings by Design	New Developments	18	24	36	40%

Enbridge 2020 Resource Acquisition Scorecard

Programs	Metrics	Metric Target			Weight
		Lower Band	Target	Upper Band	
Home Energy Conservation (HEC) Residential Adaptive Thermostats Commercial & Industrial Custom Commercial & Industrial Prescriptive Commercial & Industrial Direct Install Run-it-Right Comprehensive Energy Management (CEM) Energy Leaders	Large Volume Customers Cumulative Natural Gas Savings (m3)	75% of Target	2019 metric achievement (LRAM natural gas savings) / 2019 Large Volume Customers Resource Acquisition actual spend without overheads x 2020 Large Volume Customers Resource Acquisition budget without overheads x 1.02	150% of Target	35%
	Small Volume Customers Cumulative Natural Gas Savings (m3)	75% of Target	2019 metric achievement (LRAM natural gas savings) / 2019 Small Volume Customers Resource Acquisition actual spend without overheads x 2020 Small Volume Customers Resource Acquisition budget without overheads x 1.02	150% of Target	35%
Home Energy Conservation (HEC)	Residential Deep Savings Participants (Homes)	75% of Target	2019 metric achievement / 2019 actual program spend without overheads x 2020 program budget without overheads x 1.02	150% of Target	15%
Run-it-Right	Participants	115	153	229	7.5%
Comprehensive Energy Management (CEM)	Participants	9	12	18	7.5%

Note: Metric achievement is calculated using verified program savings used for LRAMVA purposes with fixed Net-to-Gross Factor

Enbridge 2020 Low Income Scorecard

Programs	Metrics	Metric Target			Weight
		Lower Band	Target	Upper Band	
Home Winterproofing	Cumulative Natural Gas Savings (m3)	75% of Target	2019 metric achievement (LRAM natural gas savings) / 2019 actual program spend without overheads x 2020 program budget without overheads x 1.02	150% of Target	45%
Low-Income Multi-Residential	Cumulative Natural Gas Savings (m3)	75% of Target	2019 metric achievement (LRAM natural gas savings) / 2019 actual program spend without overheads x 2020 program budget without overheads x 1.02	150% of Target	45%
Low-Income New Construction	Participants	4	6	9	10%

Note: Metric achievement is calculated using verified program savings used for LRAMVA purposes

Enbridge 2020 Market Transformation & Energy Management Scorecard

Programs	Metrics	Metric Target			Weight
		Lower Band	Target	Upper Band	
School Energy Competition	Schools	79	105	158	20%
Residential Savings by Design	Builders	22	29	44	20%
	Homes Built	2,091	2,788	4,181	20%
Commercial Savings by Design	New Developments	18	25	37	40%

EGD & Union Metric Weighting for all Scorecard Components

	Enbridge Metric Weightings and Targets				
Resource Acquisition Programs	**Proposed Metrics**	**2016 OEB-Approved Metric Weightings**	**2018-2020 Utility-Proposed Metric Weightings**	**2016 OEB-Approved Shareholder Incentive Weighting**	**2018-2020 Utility-Proposed Shareholder Incentive Weighting**
Home Energy Conservation (HEC) Residential Adaptive Thermostats Commercial & Industrial Custom Commercial & Industrial Prescriptive Commercial & Industrial Direct Install Run-it-Right Comprehensive Energy Management (CEM) Energy Leaders	Large Volume Customers Cumulative Natural Gas Savings	40%	35%	65%	55%
	Small Volume Customers Cumulative Natural Gas Savings	40%	35%		
Home Energy Conservation (HEC)	Residential Deep Savings Participants	20%	15%		
Run-it-Right	Participants	n/a	7.5%	n/a	
Comprehensive Energy Management (CEM)	Participants	n/a	7.5%	n/a	
Low-Income Programs					
Home Winterproofing	Single Family Cumulative Natural Gas Savings	45%	45%	23%	25%
Low-Income Multi-Residential	Multi-Residential Cumulative Natural Gas Savings	45%	45%		
Low-Income New Construction	Projects Completed	10%	10%		
Market Transformation & Energy Management Programs					
School Energy Competition	Schools	10%	20%	12%	20%
Residential Savings by Design	Builders	10%	20%		
	Homes Built	15%	20%		
Commercial Savings by Design	New Developments	25%	40%		
Energy Literacy	No metric proposed	0%	0%		
Run-it-Right	Participants	20%	n/a		n/a
Comprehensive Energy Management (CEM)	Participants	20%	n/a		n/a

Revised

Enbridge Gas Distribution Inc. 2018 to 2020 DSM Budget and Targets

Resource Acquisition	2018 OEB Approved Budget	2018 Proposed Budget	2019 OEB Approved Budget	2019 Proposed Budget	2020 OEB Approved Budget	2020 Proposed Budget	Total OEB Approved Budget (2018-2020)	Total Proposed Budget (2018-2020)
Home Energy Conservation	$ 18,000,000	$ 18,000,000	$ 18,360,000	$ 18,360,000	$ 18,727,200	$ 18,727,200	$ 55,087,200	$ 55,087,200
Residential Adaptive Thermostats	$ 2,175,000	$ 2,175,000	$ 2,218,500	$ 2,218,500	$ 2,262,870	$ 2,262,870	$ 6,656,370	$ 6,656,370
Commercial & Industrial Prescriptive	$ 2,232,905	$ 2,232,905	$ 2,277,564	$ 2,277,564	$ 2,323,114	$ 2,323,114	$ 6,833,583	$ 6,833,583
Commercial & Industrial Direct Install	$ 4,758,344	$ 4,758,344	$ 4,853,510	$ 4,853,510	$ 4,950,581	$ 4,950,581	$ 14,562,435	$ 14,562,435
Commercial & Industrial Custom	$ 7,361,562	$ 7,361,562	$ 7,508,793	$ 7,508,793	$ 7,658,968	$ 7,658,968	$ 22,529,323	$ 22,529,323
Small Commercial New Construction - ***Revised***	$ 1,305,566	$ -	$ -	$ -	$ -	$ -	$ 1,305,566	$ -
Energy Leaders (Large & Small C/I) - ***Revised***	$ 400,000	$ 400,000	$ -	$ 400,000	$ -	$ 400,000	$ 400,000	$ 1,200,000
Run It Right (RA portion) - ***Revised***	$ 1,584,600	$ 1,900,000	$ 1,618,946	$ 1,941,182	$ 1,653,979	$ 1,983,188	$ 4,857,525	$ 5,824,370
Comprehensive Energy Management (RA portion) ***- Revised***	$ 95,000	$ 1,000,000	$ 96,900	$ 1,020,000	$ 98,838	$ 1,040,400	$ 290,738	$ 3,060,400
Resource Acquisition Program Budget	$ 37,912,977	$ 37,827,811	$ 36,934,213	$ 38,579,549	$ 37,675,550	$ 39,346,321	$ 112,522,740	$ 115,753,681
Resource Acquisition Overhead	*$ 5,249,479*	*$ 5,249,479*	*$ 5,122,057*	*$ 5,122,057*	*$ 5,232,967*	*$ 5,232,967*	$ 15,604,503	*$ 15,604,503*
Resource Acquisition Total	**$ 43,162,456**	$ 43,077,290	**$ 42,056,270**	$ 43,701,606	**$ 42,908,517**	$ 44,579,288	**$ 128,127,243**	$ 131,358,184
Low-Income								
Home Winterproofing	$ 6,477,200	$ 6,477,200	$ 6,605,744	$ 6,605,744	$ 6,736,859	$ 6,736,859	$ 19,819,803	$ 19,819,803
Low-Income Multi-Residential - Affordable Housing	$ 3,813,296	$ 3,813,296	$ 3,889,562	$ 3,889,562	$ 3,967,353	$ 3,967,353	$ 11,670,211	$ 11,670,211
Low-Income New Construction	$ 1,400,000	$ 1,400,000	$ 1,428,000	$ 1,428,000	$ 1,456,560	$ 1,456,560	$ 4,284,560	$ 4,284,560
Low-Income Program Budget	$ 11,690,496	$ 11,690,496	$ 11,923,306	$ 11,923,306	$ 12,160,772	$ 12,160,772	$ 35,774,574	$ 35,774,574
Low-Income Overhead	*$ 1,618,681*	*$ 1,618,681*	*$ 1,653,531*	*$ 1,653,531*	*$ 1,689,078*	*$ 1,689,078*	*$ 4,961,290*	*$ 4,961,290*
Low-Income Total	**$ 13,309,177**	$ 13,309,177	**$ 13,576,837**	$ 13,576,837	**$ 13,849,850**	$ 13,849,850	**$ 40,735,864**	$ 40,735,864
Market Transformation & Energy Management								
Residential Savings by Design	$ 3,250,000	$ 3,250,000	$ 3,320,443	$ 3,320,443	$ 3,392,296	$ 3,392,296	$ 9,962,739	$ 9,962,739
Commercial Savings by Design	$ 1,075,000	$ 1,075,000	$ 1,098,300	$ 1,098,300	$ 1,122,068	$ 1,122,068	$ 3,295,368	$ 3,295,368
School's Energy Competition	$ 500,000	$ 500,000	$ 510,000	$ 510,000	$ 520,200	$ 520,200	$ 1,530,200	$ 1,530,200
Run It Right (MTEM portion) **- Revised**	$ 315,400		$ 322,236		$ 329,209		$ 966,845	$ -
Comprehensive Energy Management (MTEM portion) **- Revised**	$ 905,000		$ 923,100		$ 941,562		$ 2,769,662	$ -
Market Transformation Program Budget	$ 6,045,400	$ 4,825,000	$ 6,174,079	$ 4,928,743	$ 6,305,335	$ 5,034,564	$ 18,524,814	$ 14,788,307
Market Transformation Overhead	*$ 837,054*	*$ 837,054*	*$ 856,225*	*$ 856,225*	*$ 875,783*	*$ 875,783*	$ 2,569,062	*$ 2,569,062*
Market Transformation & Energy Management Total	$ 6,882,454	$ 5,662,054	$ 7,030,304	$ 5,784,968	$ 7,181,118	$ 5,910,347	$ 21,093,876	$ 17,357,369
Total Program Budget without Program Overhead	$ 55,648,873	$ 54,343,307	$ 55,031,598	$ 55,431,598	$ 56,141,657	$ 56,541,657	$ 166,822,128	$ 166,316,562
Total Program Overhead	*$ 7,705,214*	*$ 7,705,214*	*$ 7,631,813*	*$ 7,631,813*	*$ 7,797,828*	*$ 7,797,828*	*$ 23,134,855*	*$ 23,134,855*
Total Program Budget with Program Overhead		$ 62,048,521		$ 63,063,411		$ 64,339,485		*$ 189,451,417*
Customer Incentive Fund (10% of Program Budget without Program Overhead)	*$ -*	*$ 5,434,331*	*$ -*	*$ 5,543,160*	*$ -*	*$ 5,654,166*	*$ -*	*$ 16,631,656*
Total Program Budget with Customer Incentive Funds	$ 63,354,087	$ 67,482,852	$ 62,663,411	$ 68,606,571	$ 63,939,485	$ 69,993,650	$ 189,956,983	$ 206,083,073
Portfolio-level Overhead	*$ 3,700,000*	*$ 3,700,000*	*$ 3,758,362*	*$ 3,758,362*	*$ 3,817,891*	*$ 3,817,891*	*$ 11,276,253*	*$ 11,276,253*
Process and program evaluation	*$ 1,700,000*	*$ 1,700,000*	*$ 1,736,746*	*$ 1,736,746*	*$ 1,774,228*	*$ 1,774,228*	*$ 5,210,974*	*$ 5,210,974*
Collaboration and innovation	*$ 1,000,000*	*$ 1,000,000*	*$ 1,021,616*	*$ 1,021,616*	*$ 1,043,663*	*$ 1,043,663*	*$ 3,065,279*	*$ 3,065,279*
DSM IT Chargeback	*$ 1,000,000*	*$ 1,000,000*	*$ 1,000,000*	*$ 1,000,000*	*$ 1,000,000*	*$ 1,000,000*	*$ 3,000,000*	*$ 3,000,000*
Energy Literacy ***- Revised***	$ 500,000	$ 500,000	$ -	$ 500,000	$ -	$ 500,000	$ 500,000	$ 1,500,000
GRAND TOTAL	**$ 67,554,087**	**$ 71,682,852**	**$ 66,421,773**	**$ 72,864,933**	**$ 67,757,376**	**$ 74,311,541**	**$ 201,733,236**	**$ 218,859,326**

Revised

Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment

Executive Summary

January 2018

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

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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".[1]

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 intervenors 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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[1] 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 distribution infrastructure 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 (CPS) 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. 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 eight 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.[2]
   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 facilities 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.

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[2] 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 facilities 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[3] 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

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[3] 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.[4] 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 facility 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 avoiding or deferring infrastructure investments, and increases the risks of non-performance

[4] 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, potential a 24 hour design day.

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 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 infrastructure deferral and avoidance in the electric industry relative to the natural gas industry.

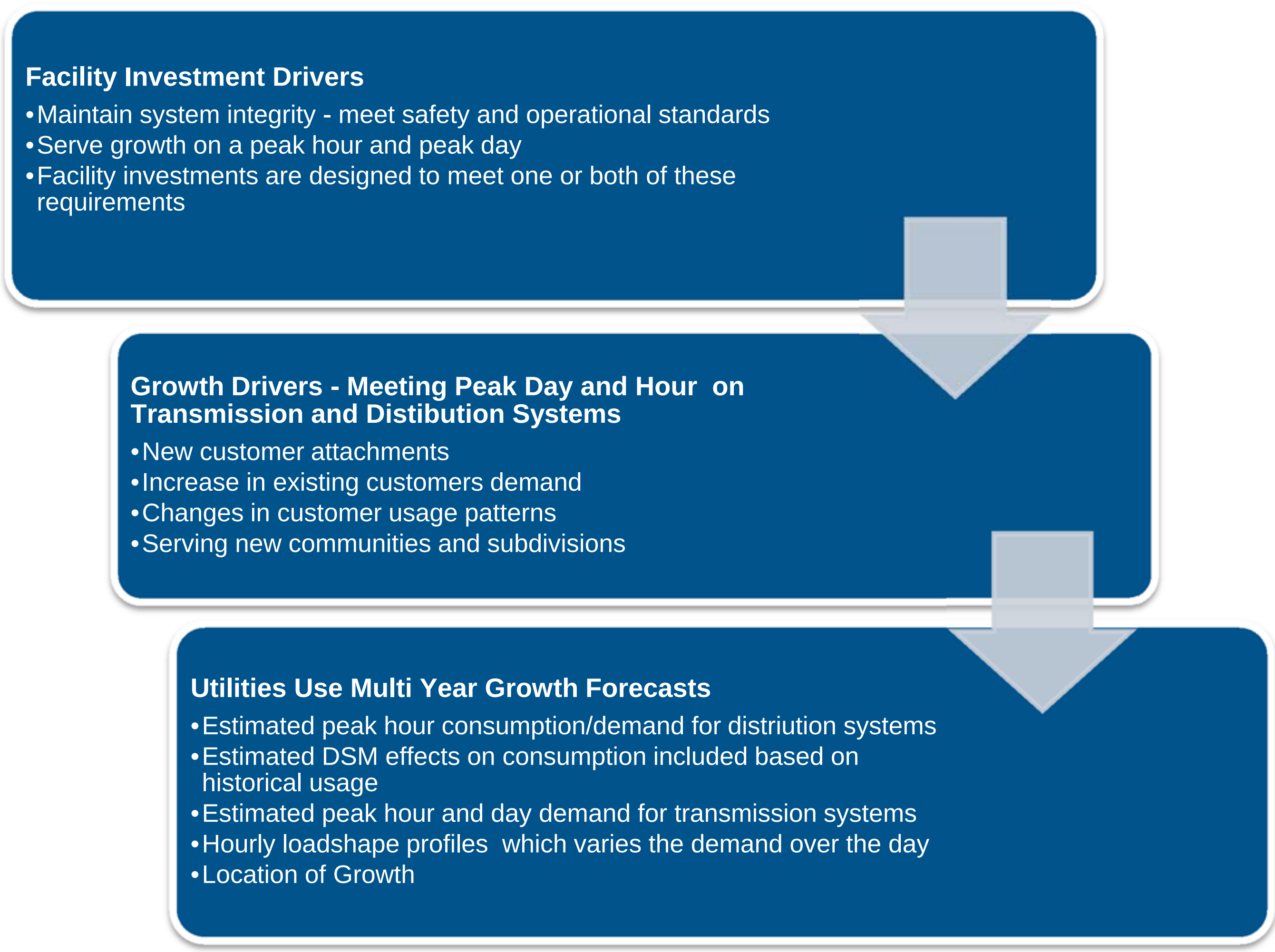
In addition, the use of DSM in the electric industry to reduce capacity requirements, and the ability to accurately measure peak demand has resulted in a better understanding of the impact of DSM on peak requirements in the electric industry than in the natural gas industry. This difference reduces the 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 Planning

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

Exhibit 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 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 at the design condition*** consistent with reasonable costs.

Facilities 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, facilities 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 loadshape (profile) that varies the demand for gas over the day.

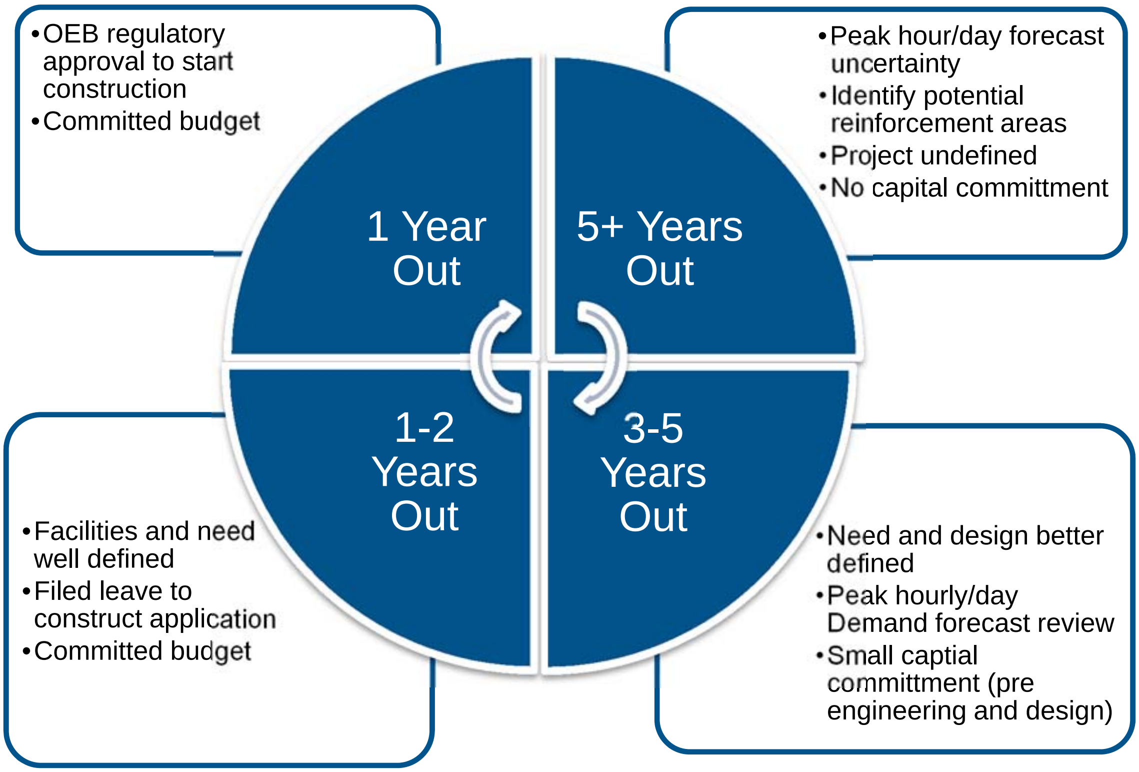
Historical gas use is used as a base to predict future consumption. The planning process includes changes in gas use resulting from historical implementation of DSM measures, as well as other factors such as improved building codes, and higher energy efficiency standards for natural gas equipment. However the facilities 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 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 Facilities 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 facilities 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 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 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 utility will not be able to serve firm customer demand. The utility may not be able to react quickly enough to avoid unplanned customer outages. If there is time, the 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 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 which 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 facilities 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 primarily 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 in Section 3.3, 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 Facilities and DSM Planning 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 delay or avoid 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 delay or avoid 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 facilities 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 4 - 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 five and six 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 2016 OEB Conservation Potential Study (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 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:

- Subsectors 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.

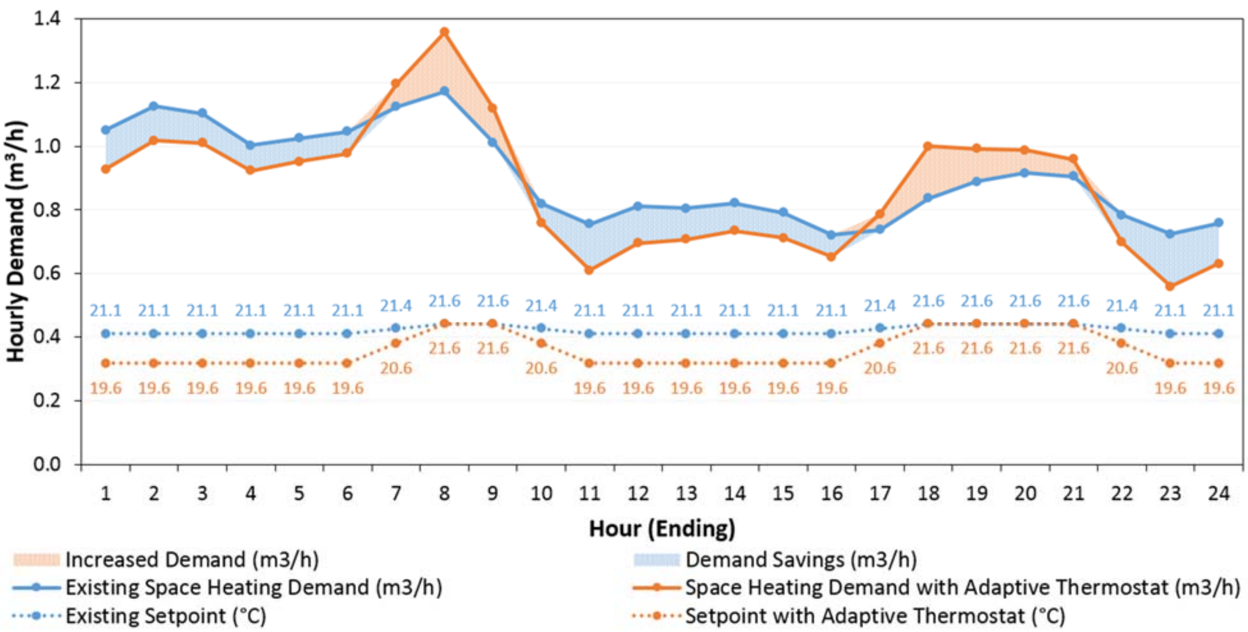
5.2 DSM Measures of Interest

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

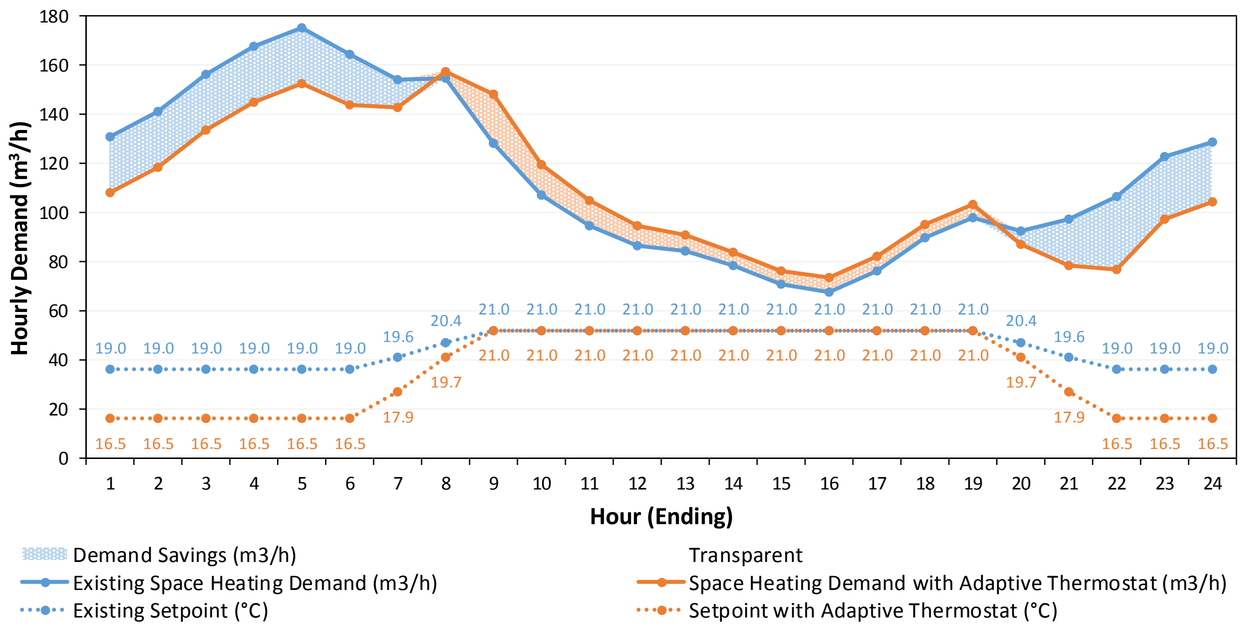
Adaptive thermostats account for a significant amount of the achievable DSM potential in both the residential and commercial sectors. According to the ICF CPS, in Ontario, adaptive thermostats account for 21.5% of the Business As Usual (BAU) Achievable DSM savings (44.8% of residential, and 2.62% of 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 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 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 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 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,[5] thermostat manufacturers including Nest, ecobee, and Honeywell indicated that they run a large number of DR programs. Although these programs are typically focused on summer peak reduction, the thermostat manufacturers indicated that DR program focused on winter peak reduction are feasible..

5.2.2 Tankless Water Heaters

Typically, tankless water heaters have a much higher rated 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.

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

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

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 5 and Exhibit 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 5, there are brief instances where the aggregate demand for the community increases if demand is considered on 5-minute increments. However, Exhibit 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 5: Comparison of Water Heater Demand for Community with Heavy Hot Water Use, 5-Minute Intervals

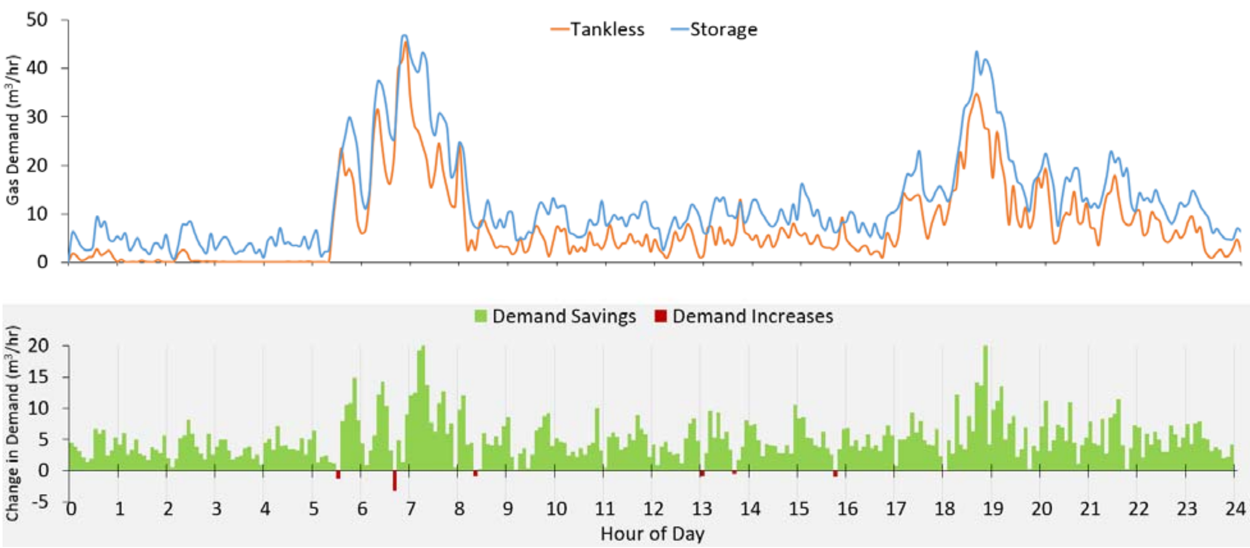
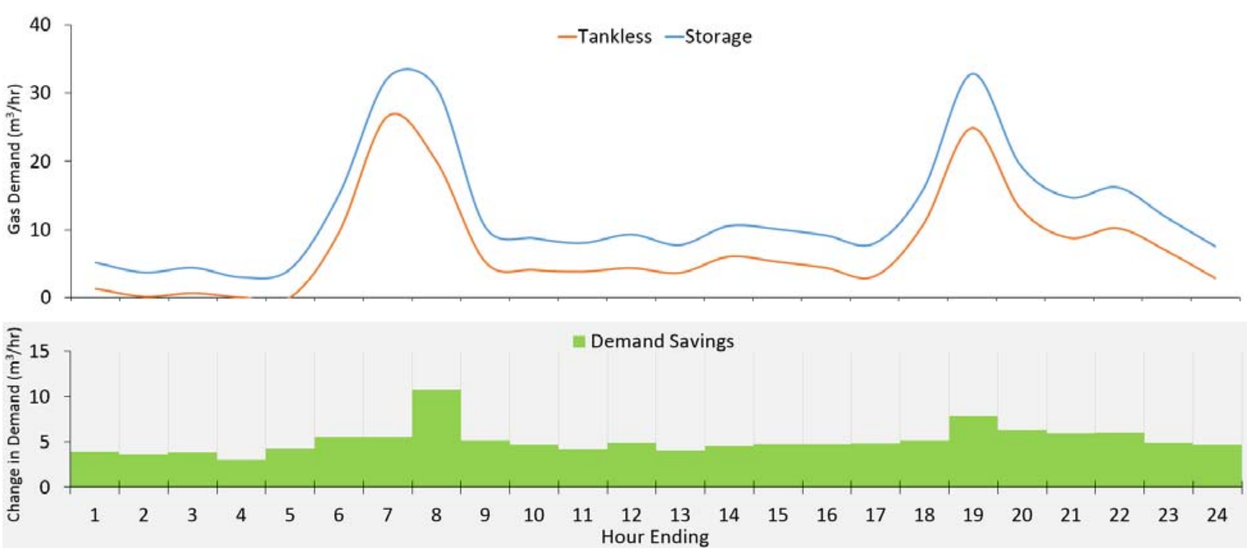


Exhibit 6: Comparison of Water Heater Demand for Community with Heavy Hot Water Use, 60-Minute Intervals



6. Potential Impacts of DSM on Facilities Requirements

ICF leveraged the results of the DSM impacts analysis described in Section Five 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

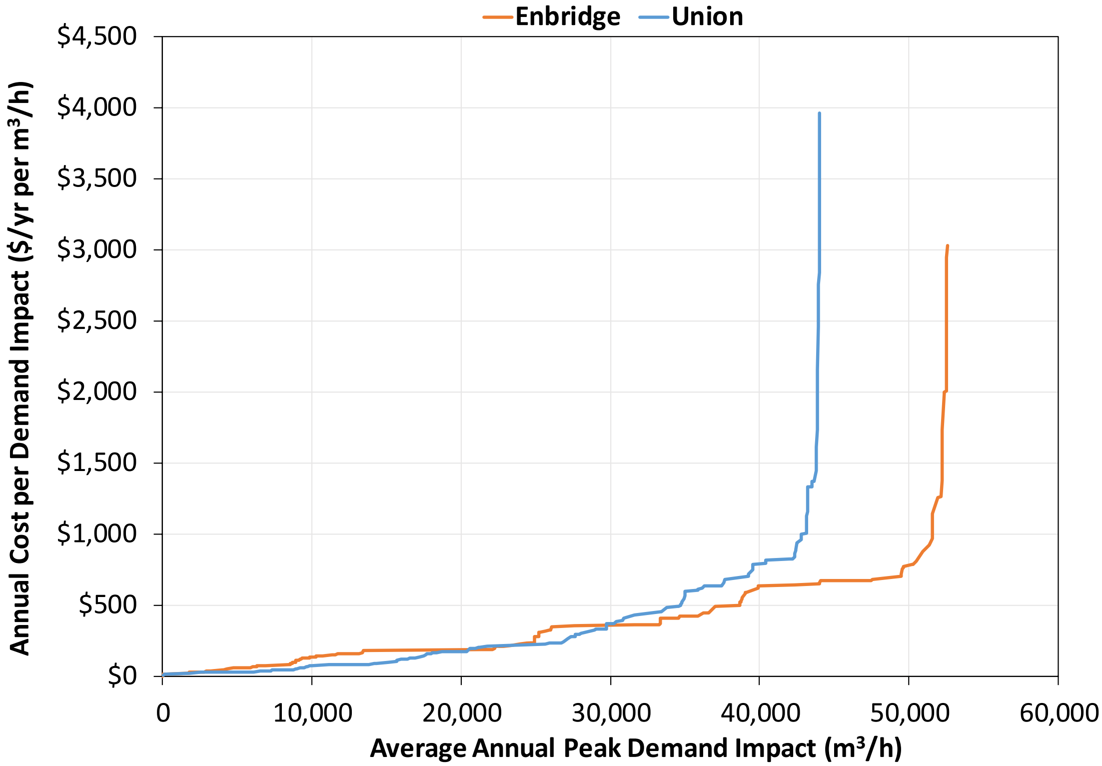
The peak hour DSM supply curve for each utility shows the relative DSM program cost (i.e. $ per m^3/h) to achieve the estimated peak hour demand impacts in each utility service territory. The DSM supply curves prioritize the measures based on their cost-effectiveness, based on the cost per unit gas demand 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 7: Broad-Based DSM Supply Curve for EGD & UG



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,[6] 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 - 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 2016 OEB Conservation Potential Study 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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[6] 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.[7] 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 facilities 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.

[7] 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.[8]
- 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 time line sufficient to ensure that infrastructure project can be reduced without impacting the Gas Utilities' ability to reliably serve natural gas system demand.

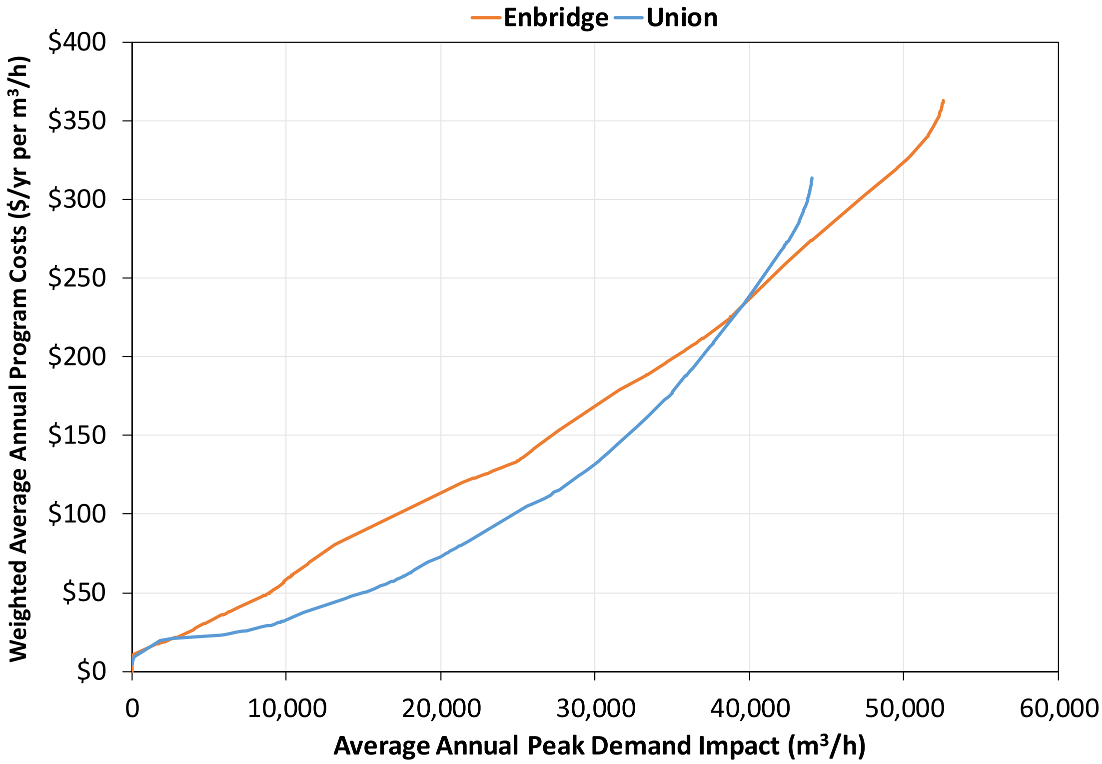
6.4.1 Broad-Based DSM

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 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 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).

[8] 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 8: Broad-Based DSM Supply Curve for EGD & UG – Weighted Average Annual Program Costs[9]



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.[10] Furthermore, the following approach was taken to compare the facilities investment projects to DSM:

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

[9] In Exhibit 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).
[10] As noted in Section 6.2, program costs were scaled up by a factor of 1.5-2 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 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 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 9: Supply Curve for Reinforcement Project in Enbridge's Central Region

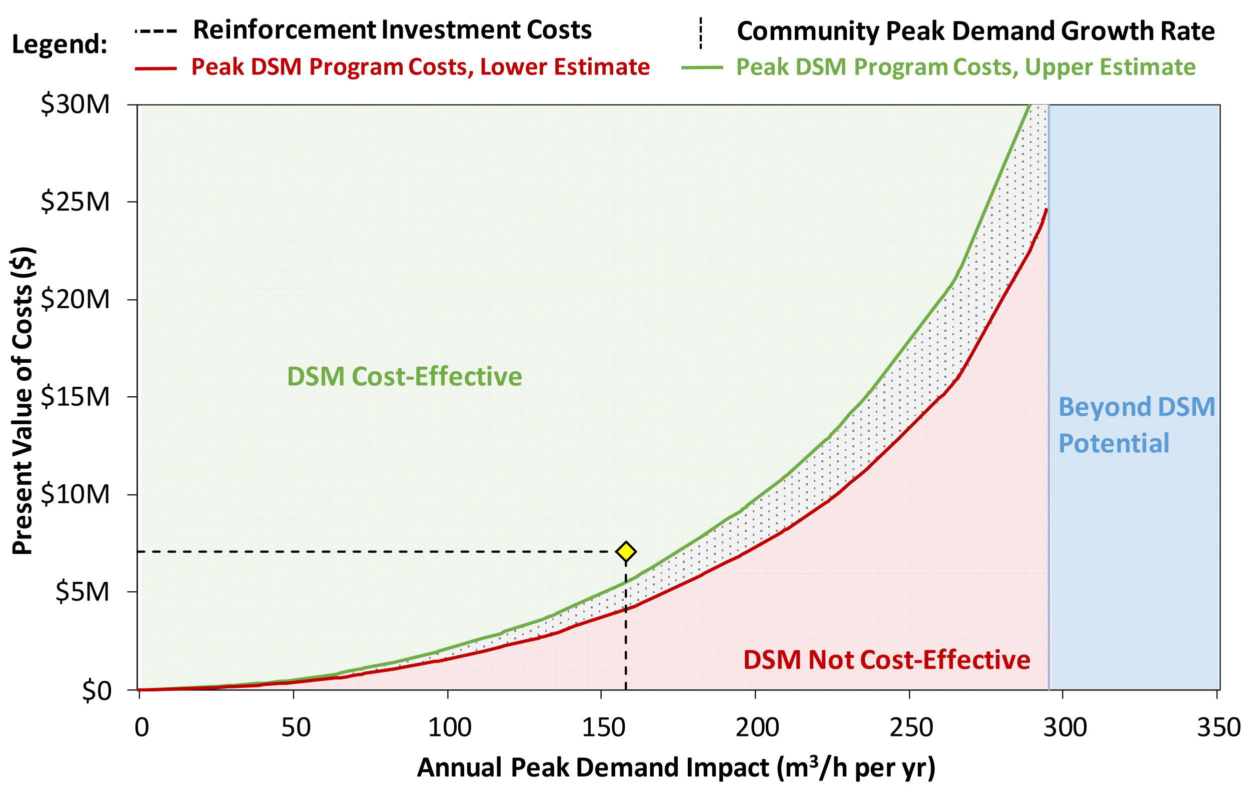
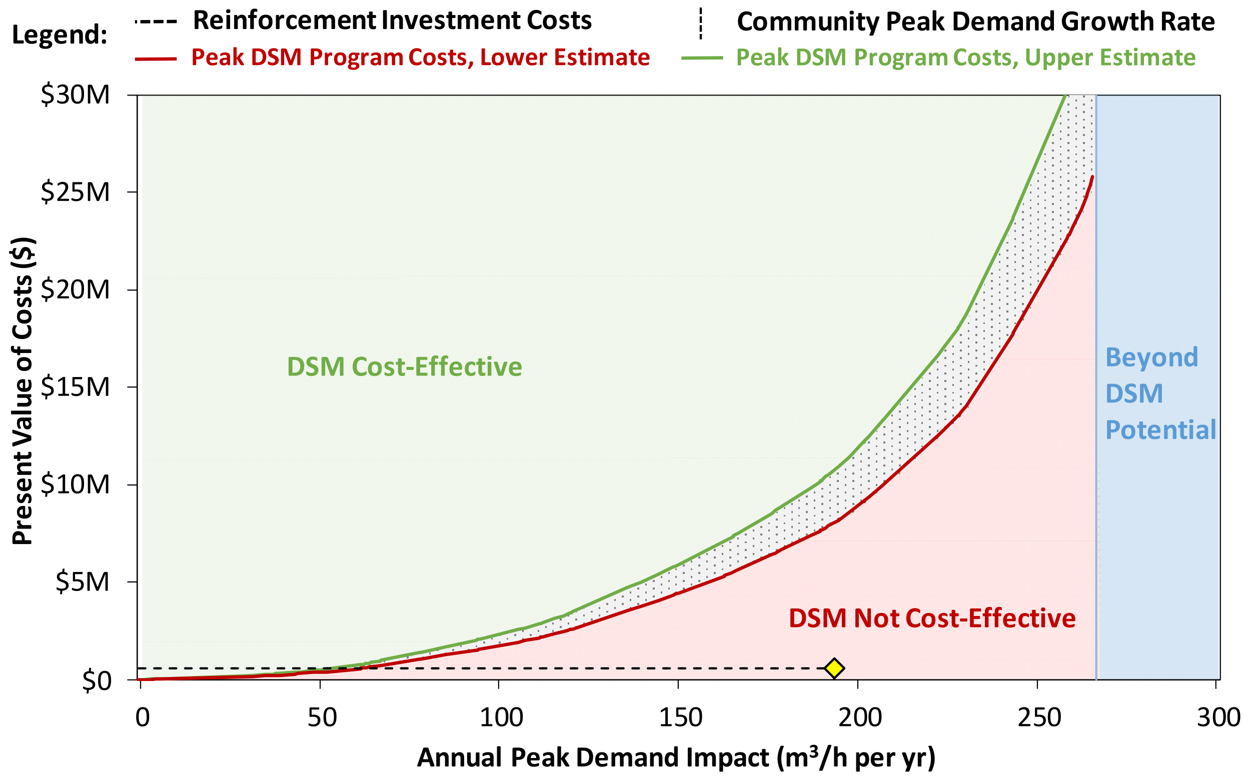


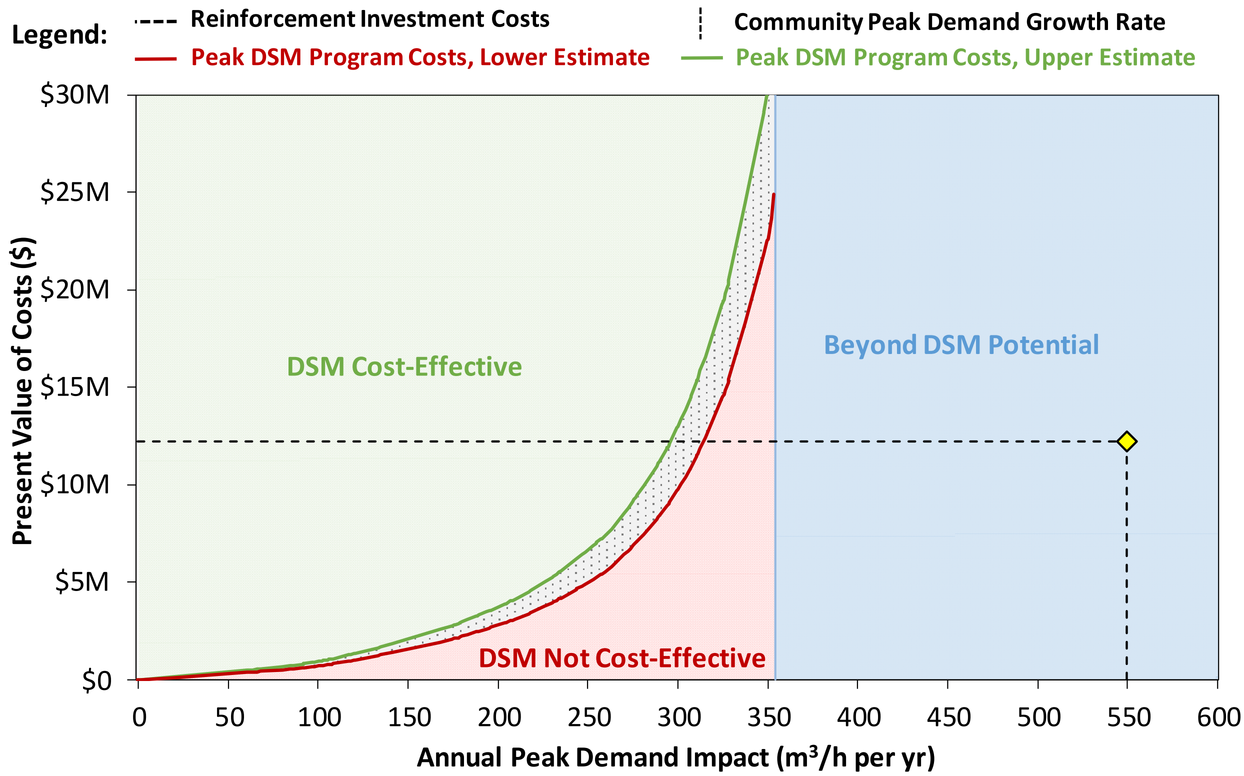
Exhibit 10 demonstrates that DSM is not always a cost-effective option for deferring reinforcement projects. In this case, Union Gas is planning to install 1.3 km of NPS 6" ST 6895 kPa pipeline to accommodate a growing community whose peak demand is increasing by approximately 194 m^3/h annually (0.7% per year). Although ICF's analysis suggests there is enough DSM potential to offset this growth, Exhibit 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 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 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 11.

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

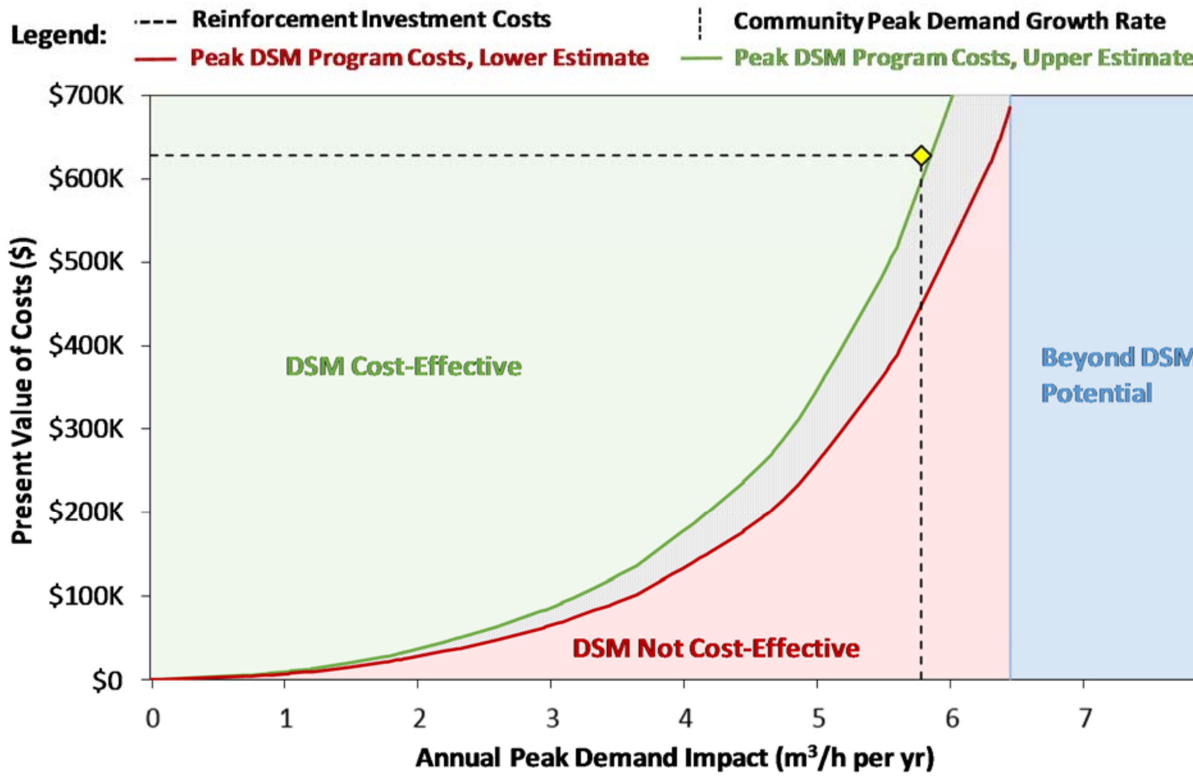


6.4.3 New Community Expansion

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 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 812, 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 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 facilities 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.[11] 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[12, 13] 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.

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

[12] 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.

[13] The planned facility expansion projects represent a subset of facilities 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 facilities 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 facilities 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 Test(s)

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 avoid or defer 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[14] 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

[14] 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.

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 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.[15]

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

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

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.

2) ***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.

3) ***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 facilities 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 facilities 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 facilities 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.

2) ***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 facilities 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 facilities 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.

3) ***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 facilities 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 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 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 2-4 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.

Appendix E

Transition Plan

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January 2018

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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 conclusions 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.

<u>Table: 1</u>

	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. 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 the Enbridge GTA Reinforcement Project, EB-2012-0451.

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 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 considerations 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 the 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 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

[2] Report of the Ontario Energy Board 2015-2020 Natural Gas DSM Framework Page 1

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]

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

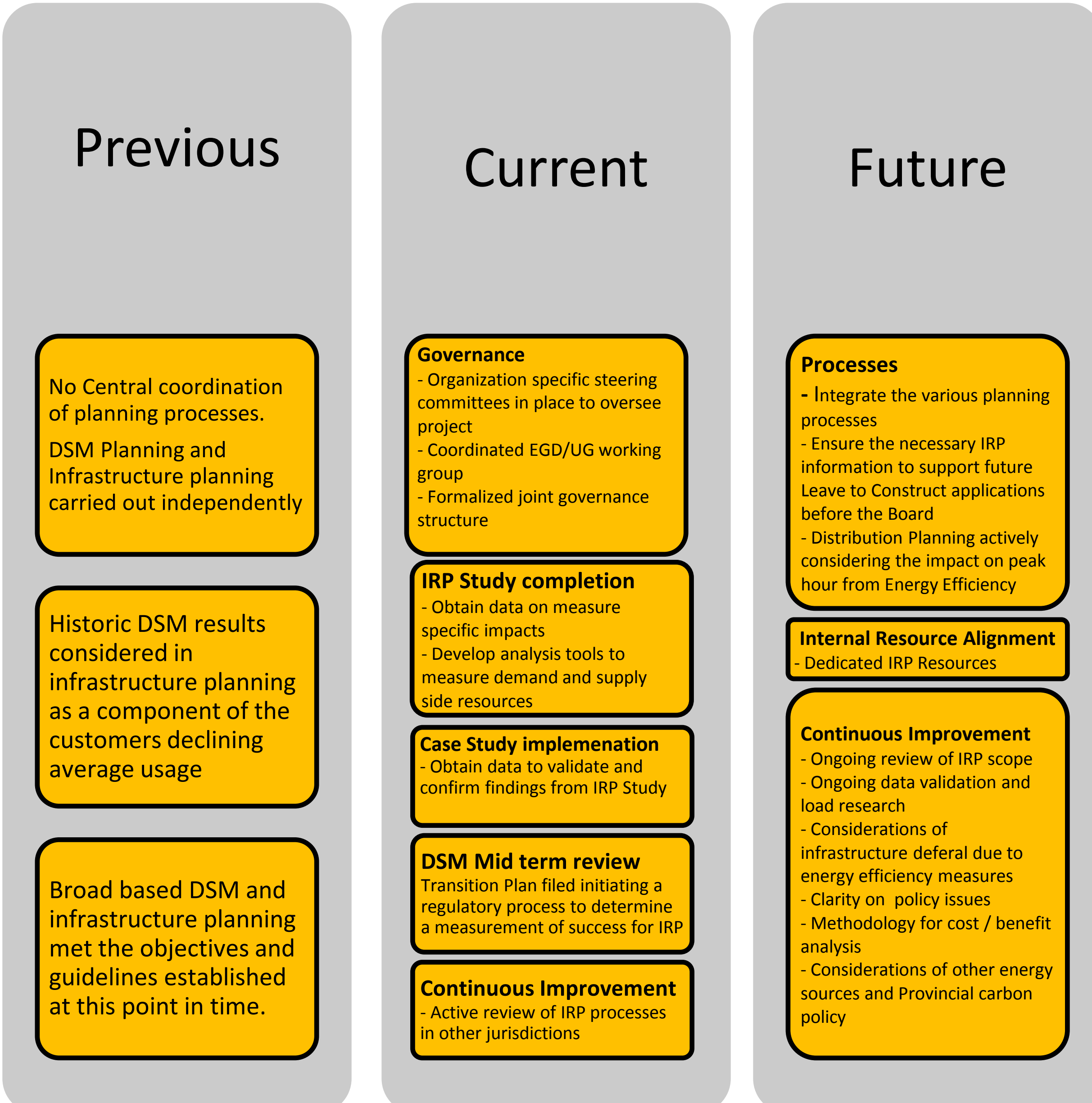
[3] https://www.oeb.ca/consumer-protection/how-we-protect-consumers/consumer-charter

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.

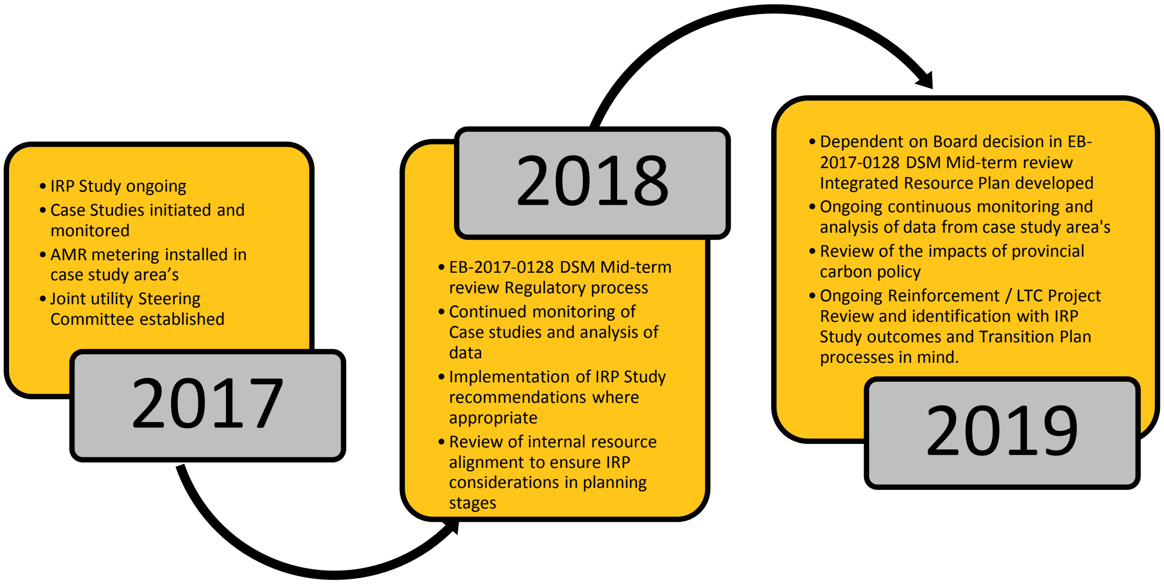
Phase 2 – 2018:

- 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.