Ontario Energy Board

EB-2014-0134

Filing Guidelines to the Demand Side Management Framework for Natural Gas Distributors (2015-2020)

December 22, 2014

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1.0 INTRODUCTION

The Filing Guidelines to the Demand Side Management ("DSM") Framework for natural gas distributors (the "DSM Guidelines") is a companion document to the DSM Framework for Natural Gas Distributors (2015-2020) (the "DSM framework"). The DSM Guidelines are intended to provide a common understanding of the key elements related to DSM activities and outline the specific information the Board expects the natural gas utilities to take into consideration when developing their DSM Plans and filing applications. The sections below build on the direction provided in the DSM framework and provide further details related to the sections discussed in the DSM framework.

2.0 GUIDING PRINCIPLES

The Board has outlined a set of guiding principles in Section 2 of the DSM framework. The gas utilities are expected to address the guiding principles in the design of their DSM plans. The gas utilities should include a section in their multi-year DSM plan applications which discusses how they have incorporated the Board's guiding principles throughout the multi-year plan.

3.0 DSM TARGETS

Section 3.0 of the DSM framework discusses the Board's direction to the gas utilities regarding DSM Targets. In addition to the guidance provided in the framework, the gas utilities can include targets for important program elements such as:

- the number of low-income participants enrolled in a DSM program,
- the number of houses or businesses who have installed at least one energy efficient technology that will produce long-term natural gas savings,
- the number of participants enrolled in natural gas DSM programs that have been coordinated and/or integrated with electricity conservation and demand management ("CDM") programs, or
- the number of customers that have participated in a new program that has been identified as a key priority by the Board.

Program concepts such as on-bill financing[1] and social benchmarking, as well as activities related to implementing natural gas conservation into infrastructure planning processes should be priorities in the first half of the new multi-year DSM term. At the mid-term review, the Board and parties will have an opportunity to assess the progress the gas utilities have made in implementing these key priorities and to what extent they are a standard function of their overall DSM portfolio. The Board may then determine whether it is appropriate to continue to have targets for these areas.

As part of their multi-year DSM plans, the gas utilities should provide the following in support of the proposed targets:

- Annual targets (both natural gas savings and other performance metrics)
- 2020 targets (both natural gas savings and other performance metrics)
- Documentation of how the gas utilities' most recent achievable potential studies have contributed to the development of their natural gas savings targets, performance metrics and proposed budgets
- Sensitivity analysis that shows how both annual and 2020 targets interact and increase/decrease based on different budget scenarios. The gas utilities should provide a minimum of three target scenarios based on different budget amounts
- What challenges the gas utilities will face in reaching the targets and what factors will cause targets to be possibly exceeded or not to be exceeded
- Explanation of how the gas utilities have addressed the key priorities outlined in the DSM framework in their performance scorecards

4.0 DSM BUDGETS

Section 4.0 of the DSM framework discusses the Board's direction to the gas utilities regarding DSM Budgets. In addition to the guidance provided in the framework, at a minimum, the gas utilities should provide the following in support of their DSM budgets:

- How the DSM budget will address the DSM framework's guiding principles and key priorities
- How the DSM budget will result in significant natural gas savings
- The rationale for why increases to total cost impacts for customers is appropriate
- The benefits to the customer, system and utility that will result for the proposed budgets

[1] Consistent with the government of Ontario's policy.

- How the gas utility plans to stage in budget increases, or ramp up its activities
- Breakdown of all DSM budget components for all proposed programs, including proposed customer incentives, overheads/administration, and evaluation costs
- Proposed annual DSM costs (budget and shareholder incentive) by rate class as well as the anticipated rate impact for a typical customer in each rate class

5.0 SHAREHOLDER INCENTIVE

Section 5.0 of the DSM framework outlines the Board's direction related to the total annual maximum shareholder incentive available to both Enbridge and Union.

As outlined in Section 5.2 of the DSM framework, three levels of achievement should be provided on the scorecard(s) for each metric: one at each of 75%, 100% (target), and 150%. No incentive will be provided for achieving a scorecard weighted score of less than 75%. For each metric on the scorecard, results will be linearly interpolated between 75% and 100%, and between 100% and 150%. Metric results below 75% will be interpolated using the 75% and 100% targets, metric results above 150% will be interpolated using the 100% and 150% targets. The incentive amount should be capped at the scorecard weighted score of 150%. The maximum incentive amount allocated to each DSM program should equal the sum of the maximum incentive amounts available for achieving weighted scores of 150% or above on all the scorecards.

In order for a gas utility to earn the maximum annual incentive amount they will need to meet aggressive annual natural gas savings targets and address the key priorities outlined in the DSM framework. In order to motivate the gas utilities to dedicate resources to address the key priorities outlined in the DSM framework, a portion of the maximum shareholder incentive amount available for overachieving 100% of targets (i.e., from the 60%, or $6.3M, portion of the overall incentive) can be allocated to these metrics. This acknowledges that some of the key priorities may not directly result in quantifiable natural gas savings, and may require the gas utilities to enter new areas of program development. For example, if a gas utility proposes to dedicate 10% of the overachievement incentive amount (i.e., 10% of $6.3M or $0.6M) to the key priority metrics, approximately $5.7M would remain available to the gas utility if it achieves between 100% and 150% of its targets. This structure maintains the full shareholder incentive amount available at 100% of target (or $4.2M) ensuring the gas utilities are properly motivated to undertake DSM activities, while providing an additional incentive to pursue the key priorities outlined in the DSM framework. The gas utilities should include evidence that supports its proposed shareholder incentive allocation, including historic program targets and results.

Cost-Efficiency Incentive

As discussed in the DSM framework, a cost-efficiency incentive is available to the gas utilities. This incentive rewards the gas utilities for efficiently spending their approved annual DSM budgets while meeting their natural gas savings targets. In the event that a gas utility is able to meet its overall annual natural gas savings target, the gas utility will be eligible to carry forward any remaining approved budgets amounts into the immediately following year. The approved budget amounts to be carried forward will be incremental to the gas utilities' approved DSM budget for the immediately following year, and can be used to help achieve the approved targets for the following year.

6.0 PROGRAM TYPES

The Board expects the gas utilities to transition their DSM activities to address the key priorities outlined by the Board in the DSM framework. As part of this transition the Board expects that the gas utilities will explore and include information on how they plan to incorporate the elements and new program types discussed below into their DSM Plans. Ultimately, the gas utilities have flexibility in deciding what programs to include in their proposed multi-year DSM plans to ensure they are cost-effective and will enable the achievement of significant benefits, particularly long-term natural gas savings.

Elements to consider incorporating into the 2015 to 2020 multi-year DSM plans:

Key priorities identified in the LTEP and Conservation Directive:

a) Implement DSM programs that can help reduce and/or defer future infrastructure investments;

As discussed further in Section 13 below, the Board is of the view that the gas utilities should analyse the effects that DSM may have on its infrastructure planning processes. The gas utilities should provide a clear indication how they will study the effects that DSM can have on deferring, postponing or reducing future capital investments. The Board is of the view that this analysis is necessary in order for the gas utilities to effectively develop a specific plan to identify the opportunities to implement DSM programs that may be able to address infrastructure planning needs at the regional and local levels.

b) Develop new and innovative programs, including flexibility to allow for on-bill financing options;

In order to allow for a greater number of customers to participate in DSM programs, the gas utilities should allow the flexibility to provide various options related to financing energy efficiency upgrades. As the costs for some energy efficiency upgrades can be substantial (e.g., thermal upgrade improvements, furnace, hot water heater, etc.), it may be reasonable for the gas utilities to offer a financing option to its customers. The new multi-year DSM plans should allow for this type of program.

c) Increase collaboration and integration of natural gas DSM programs and electricity CDM programs;

As discussed in the DSM Framework at Section 10.0, the Board expects the gas utilities will achieve greater efficiencies in a number of program areas if they coordinate and integrate DSM programs with electricity CDM programs.

d) Expand the delivery of low-income offerings across the province;

The Board is of the view that low-income programs should be available to low-income consumers across the province where natural gas service is available by the end of the first year of the new DSM framework. Energy conservation is a critical area that can help customers better manage their bills, and therefore low-income consumers should have the opportunity to participate in DSM programs. More on low-income programs can be found below in Section 6.4.

The Board identified priorities:

e) Implement DSM programs that are evidence-based and rely on detailed customer data, including:

i) Provide a greater level of customer-specific educational information and data to help customers use natural gas more efficiently;

The gas utilities should undertake initiatives that enable their customers to better understand their current usage levels through customer-specific information. By increasing the amount and frequency of customer-specific natural gas usage information provided, the customer will be able to better take advantage of available energy efficient technologies and manage their energy usage. This type of information can be incorporated into a broader program, be used as a marketing tool to leverage other offerings, or be a standalone offering, depending on how the gas utility decides to design the offering to maximize long-term energy savings.

ii) Benchmark energy usage to enable detailed data analysis and comparison of usage with other similar customers and pre/post program participation;

The Board is of the view that opportunities exist for the gas utilities to explore programs that provide more information to customers to allow them to compare their usage levels with their own energy systems as well as other customers with similar characteristics – either those in their neighbourhood or town/city, or other households or businesses of similar size, usage level, age, or occupancy level.

Benchmarking programs enable the customer to gain more insight into the opportunities that may exist for them to upgrade their efficiency levels and conserve greater levels of natural gas. These programs do not require significant financial customer incentives, although customer incentives can work in concert with the information provided by the utilities. This type of program is driven by increasing the knowledge and awareness of customers with personalized, customer-specific information with the goal of empowering customers with a certain level of data to ensure that significant natural gas consumption reductions are achieved throughout the term of the DSM framework.

f) Ensure that programs take a holistic-approach and identify and target all energy savings opportunities throughout a customer's home or business.

The Board expects that the gas utilities will continue to offer traditional, financial incentive based programs, where the utility provides customers with a financial incentive (e.g., discounts or rebates to cover a portion of the costs) that make the adoption of energy efficient upgrades more attractive and encourages customers to participate in a DSM program (e.g. space or water heating for residential customers; pre-rinse valves, air door heat containment systems, or kitchen ventilation systems for small commercial customers; or, space heating systems for larger customers). However, the Board is of the view that these programs should only be continued to the extent that the financial incentive truly drives and influences the customer's decision to participate in the program and results in a change in behaviour that would not have been experienced without the presence of the DSM program. Further, the Board is of the view that the gas utilities should strive to include a larger portion of technologies and energy efficient measures that produce natural gas savings over a longer period of time as opposed to those which result in short term benefits. The gas utilities should ensure they have appropriately designed their program to identify all areas of efficiency improvements in the customer's home or business. By focusing on complete retrofits and long-life measures, the gas utilities will be providing a greater opportunity for customers to realize more significant benefits and receive more value for their investment.

6.1 DSM Programs with Long-Term Natural Gas Savings

A central component of the gas utilities' new DSM Plans should be a continued transition from programs that deliver short-term benefits, to those with long-term natural gas savings which will provide long-term value to energy consumers. By delivering DSM programs, the gas utility is in a unique and important position to help customers better manage their consumption and use natural gas more efficiently. This can ultimately reduce overall demand which has the potential to lower long-term costs to the gas utilities to the benefit of consumers. Programs should be designed and prioritized to deliver results that will lead to total bill reductions and continue to be in place over the long-term.

6.2 Pilot Programs

In addition to offering programs to its customers, the gas utilities should consider how pilot programs can help to better understand new program designs and delivery concepts, ultimately leading to greater natural gas savings and market penetration of programs. Pilot programs should involve the testing or evaluation of energy efficient technologies, alternative financing mechanisms or detailed, customer-specific natural gas usage information that may serve as a model for future DSM program development.

The Board further encourages the gas utilities to explore pilot programs based on a pay-for-performance funding/incentive recovery model, discussed in Section 5.0 of the DSM framework. With these types of programs, the gas utilities would be compensated for the natural gas savings achieved by the programs, rather than a direct full cost recovery model. Both the costs of the program and the shareholder incentive amount should be built into the proposed rate ($/m^3) of verified natural gas savings and be structured so that this price considers the additional risk of this compensation model.

6.3 Programs for Large Volume Customers

The Board continues to be of the view that programs designed for large volume customers are not mandatory. As discussed in Section 6.2 of the DSM framework, if a gas utility deems it appropriate to offer a program for its large volume customers[2], the program should be offered under a fee-for-service model with the primary focus on providing value-added, technical expertise to customers, including engineering studies on how the customer can more efficiently use their current energy systems and identifying areas of efficiency improvements. If a gas utility proposes a large volume fee-for-service program as part of its multi-year DSM plan, at a minimum, it should include the following program details:

- The rate classes of the targeted customers
- The anticipated costs the participating customers will need to provide in order to receive service and what the various services (e.g., facility audit, operational review, engineering study, etc.) are expected to cost
- The anticipated participation rates
- The projected annual and lifetime savings goals
- The forecasted administrative, marketing and evaluation costs, as well as the maximum shareholder incentive allocated to the program
- The subsequent total cost and rate impacts for all customers in the large volume rate classes

Costs from the large volume program should generally be recovered directly from the participating customer and not allocated to the large volume rate class. However, the gas utilities are able to allocate the administrative costs from the large volume fee-for-service program to the large volume rate classes, as discussed in the DSM framework. Administrative costs are generally the costs of staff who work on DSM activities. These costs are often differentiated between support and operations staff. Support staff costs are considered fixed costs or “overhead” that occur regardless of the level of customer participation in the programs. Operations staff costs vary, depending on the level of customer participation. The gas utilities should not allocate any operations staff costs to the large volume rate classes. These costs should be included in the fee charged by the gas utility to participating large volume customers.

6.4 Low-Income Programs

The purpose of DSM programs tailored to low-income consumers is to recognize that, these programs more adequately address the challenges involved in providing DSM programs for, and the special needs of, this consumer segment.

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[2] Large volume customers are those customers in EGD’s Rate 125 class, and Unions Rate T1, Rate T2 and Rate 100 classes.

Low-income programs are a set of resource acquisition and market transformation programs. Hence, the distinctive features of low-income programs result from additional guiding principles and design characteristics, as opposed to the nature of the programs per se.

These programs are critically important in helping the most vulnerable customers manage their natural gas bills. The directive to the Board from the Minister of Energy specifically identified coordination and integration of low-income DSM programs with low-income electricity CDM programs. The Board has provided a list of program requirements and eligibility criteria related to low-income DSM programs below. The list below was developed by a low-income working group in advance of the 2012 DSM Guidelines. The requirements and eligibility criteria can be used by the gas utilities when developing their low-income programs as part of their new multi-year DSM plans. The Board appreciates that further advancements and better information may now exist with respect to the program requirements and eligibility criteria for low-income participants. The gas utilities should ensure that the requirements and criteria outlined below remain current and relevant (e.g., include any appropriate updates to properly reflect the inclusion of tenants in privately-owned, multi-family buildings). Any updates and/or proposed changes to the requirements or criteria below should be included in the gas utilities' new multi-year DSM plan applications for the Board and other interested parties to review. The Board will approve any updates at the time it hears the new multi-year DSM plan applications.

Low-Income Program Requirements

In addition to general requirements of DSM programs, low-income natural gas DSM programs should:

1. Be accessible to low-income natural gas consumers;

    a) Be accessible province-wide where gas is available;
    b) Be provided to private low-income, multi-residential buildings, including the private rental market, throughout the 2015 to 2020 term;

c) Require no, or low[3], upfront cost to the low-income energy consumer and result in an improvement in energy efficiency within the consumer's residence; and
d) Address non-financial barriers (e.g. communication, cultural and linguistic).

2. Be delivered in a cost-effective manner;
   a) While low-income programs may not have a positive total resource cost test result, it is still important for the gas utilities to be efficient in managing costs to achieve the maximum results for the budget.

3. Provide a simple, non-duplicative, integrated and coordinated application, screening and intake process for the low-income conservation program that covers all segments of the low-income housing market including, for example, homeowners, owners and occupants of social and assisted housing (as defined below), and owners of privately owned buildings that have low-income residents;

   a) Gas distributors should develop specific criteria for determining the eligibility to participate in these programs.

4. Provide integrated, coordinated delivery, wherever possible, with electricity distributors and natural gas utilities; provincial and municipal agencies; social service agencies and agencies concerned with health and safety issues;

   a) Encourage collaboration with partners such as private, public and not-for-profit organizations for program delivery.

5. Include direct install elements;

   a) Provide a turnkey solution from the perspective of the participant such that the participant deals with one entity for the program which coordinates all elements of delivery;
   b) Emphasize deep measures that may include, where applicable, energy efficiency, demand response, fuel-switching, customer based generation and renewables; and
   c) Capture potential lost opportunities for energy savings, including new construction of low-income/affordable housing.

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[3] It is generally expected that low-income DSM programs will require no upfront costs to the low-income consumer. However, if a gas utility feels it is appropriate to require some level of upfront costs from the low-income consumer, it must clearly show the benefits of this approach and discuss the rationale for the proposal.

6. Provide an education and training strategy that;

    a) Encourages behaviour change of program participants toward a culture of conservation;
    b) Helps low-income energy consumers help themselves; and
    c) Helps program participants to understand the benefits of participating in the low-income DSM program and conservation, in general.

7. Help channel partners attain necessary skills.

Low-Income Program Eligibility Criteria

To facilitate coordination between low-income electricity CDM and natural gas DSM programs, eligibility criteria for low-income consumers should be consistent with those outlined below. As developed by a low-income working group prior to the 2012 DSM Guidelines, the four eligibility criteria for low-income natural gas DSM programs are: 1) income eligibility; 2) utility bill payment responsibility; 3) building eligibility; and 4) landlord consent (where applicable). Ultimately, it is the responsibility of the natural gas utilities or the contracted program delivery agent to confirm participant eligibility based on all four criteria.

1. Income Eligibility Criterion

Participants of the low-income natural gas DSM program must meet at least one of the following four requirements:

    a) Household Income at or below 135% of the most recent Statistics Canada pre-tax Low-Income Cut-Offs (“LICO”) for communities of 500,000 or more, as updated from time to time;

OR

    b) A recipient of one of the following social benefits in the last twelve months:
        i) National Child Benefit Supplement;
        ii) Allowance for the Survivor;
        iii) Guaranteed Income Supplement;
        iv) Allowance for Seniors;
        v) Ontario Works;
        vi) Ontario Disability Support Program; or

vii) LEAP Emergency Financial Assistant Grant.

c) All participants who reside in social and/or assisted housing are eligible for low-income natural gas DSM programs, as long as the housing provider is able to provide in writing an indication that their residents are income eligible. Eligibility criteria for social housing residents will be reviewed by the agent responsible for low-income program eligibility screening and a complex-wide eligibility waiver/approval will be issued if eligibility criteria are consistent with income criteria used for the program. The natural gas utilities will use their discretion to implement this policy in order to ensure that social housing residents that participate in the program would otherwise be eligible under income eligibility criteria; or

d) Any household that resides in a community that is targeted for the neighbourhood blitz treatment (for example, neighbourhoods in which greater than or equal to 40% of households qualify according to the LICO thresholds established for the program) will be eligible for basic low-income natural gas DSM measures; these homes must meet at least one of the other income criteria described above to qualify for deep DSM measures.

The natural gas utilities, through their agent responsible for low-income program eligibility screening, must ensure that all participants (with the exception of social and assisted housing residents) provide proof of income in the form of a copy of their last income tax assessment or social benefit statement. The agent responsible for low-income program eligibility screening must verify that this proof meets the income criteria outlined above. The natural gas utilities (or their delegate) will be responsible for obtaining a landlord waiver form in which the landlord will acknowledge and consent to the implementation of program measures and treatments in participating homes where applicable.

2. Utility Bill Payment Responsibility Criterion

Participants must pay their own utility bill, except where they reside in social and/or assisted housing. All residents of social and/or assisted housing (in Part 9 buildings, as defined by the 2006 Ontario Building Code ("OBC")) will be eligible for participation in the program provided they meet all other eligibility requirements. Only natural gas-heated homes will be eligible for building envelope measures.

3. Building Eligibility Criterion

Consumers must be residents of single family low-rise buildings (more fully defined by Part 9 of the OBC as residential buildings of three stories or less with a footprint of less than 600 square metres), as well as mobile homes. Residents of privately-owned buildings defined by Part 3 of the OBC that pay their own utility bill will not be eligible for deep or building envelope improvement measures, but will nonetheless be eligible for other in-suite low-income natural gas DSM measures provided that their landlord consents to their participation in the program.

4. Landlord Consent Criterion (if applicable)

   a) Private building residents: Tenants living in privately rented homes must obtain the consent of their landlord to participate in the program.

   b) Social and assisted housing residents: Providers of social and/or assisted housing will be the first point of contact for social and/or assisted housing residents and must provide their consent for residents of their buildings to participate in the program.

      i) Once a social and assisted housing provider has agreed to participate, their residents will be invited to participate in the program (i.e., to determine if equipment that the resident owns qualifies for replacement); and
      ii) If a social and/or assisted housing resident identifies themselves to the program, the natural gas utilities (or their delegates) will either direct the resident to contact their housing provider, or the natural gas utilities (or their delegates) will contact the housing provider and encourage them to participate.

6.5 Market Transformation Programs

Market transformation programs are focused on facilitating fundamental changes that lead to greater market shares of energy-efficient products and services. These programs should also focus on influencing consumer behaviour and attitudes that support reduction in natural gas consumption. They are designed to make a permanent change in the market place over a long period of time. These programs include a wide variety of different approaches. For example, such program approaches may include offering conferences and tradeshows for building contractors; radio advertising targeted to natural gas customers encouraging them to reduce energy consumption by installing more energy efficiency space heating; and educational materials distributed to schools to teach children about saving energy and protecting the environment.

Market transformation programs can be applicable to lost opportunity markets where, for example, equipment is being replaced or new buildings are being built. Lost opportunity markets refer to DSM opportunities that, if not undertaken during the current planning period, will no longer be available or will be substantially more expensive to implement in a subsequent planning period. An example of preventing a lost DSM opportunity would be improving the thermal envelope of a building at the time the building is undergoing unrelated major renovation work.

It can be rather difficult to provide definitive evidence that the natural gas utilities' market transformation programs are responsible for the reported results; while they generally promote the energy efficiency message, their savings may be indirect. In comparison, resource acquisition and performance-based programs seek to achieve direct, measurable savings customer-by-customer. Some programs are a mix of market transformation and resource acquisition programs and seek both outcomes – fundamental changes in markets and direct, measurable energy savings.
Market transformation programs operate where competitive forces are not expected to yield the results sought or not within an acceptable timeline. The natural gas utilities can help fill in some of the gaps in achieving market transformation results or accelerate the achievement of those results, but should otherwise limit their participation in this type of program. Market transformation programs can be focused on lost opportunities and be outcome-based (e.g., selected and designed to achieve measurable impacts on the market, such as increasing the market share of a DSM technology) as opposed to output-based (e.g., delivering a given number of workshops).

6.6 Program and Portfolio Design

Overall, the design of the natural gas DSM programs and the gas utilities' entire DSM portfolio should be informed by the guiding principles outlined in Section 2.0 of the DSM framework.

To help ensure that an appropriate balance among the guiding principles are maintained and that changes to the DSM plan are consistent with the other elements of the DSM framework, the gas utilities should apply to the Board for approval if they decide to re-allocate funds from programs that have been approved as part of the gas utilities' multi-year DSM plan application to new programs that are not part of their Board-approved DSM Plan. However, if the gas utilities decide to re-allocate funds amongst existing, approved DSM programs, the gas utilities should inform the Board, as well as their stakeholders, in the event that cumulative fund transfers among Board-approved DSM programs exceed 30% of the approved annual DSM budget for an individual DSM program (either the program the funds are being transferred from, or the program the funds are being transferred to). This level of guidance is meant to ensure that adequate flexibility in DSM program and portfolio design is maintained, while recognizing that the gas utilities are ultimately responsible and accountable for their actions. This flexibility should ensure that the gas utilities can continuously react to and adapt with current and anticipated market developments.

7.0 PROGRAM EVALUATION (including Adjustment Factors)

Evaluation, Measurement and Verification ("EM&V") is the process of undertaking studies and activities aimed at assessing the impacts (e.g., natural gas savings) and effectiveness of an energy efficiency program on its participants and/or the market. Monitoring and EM&V also provides the opportunity to identify ways in which a program can be changed or refined to improve its performance. It is important to ensure proper EM&V studies are being undertaken to enable the pursuit of cost-effective DSM programs. Moreover, EM&V of DSM activities is important to support the Board's review and approval of prudent DSM spending, requests to recover lost revenues that result from DSM programs and shareholder incentive amounts claimed by the natural gas utilities.

7.1 Evaluation Process

As discussed in Section 7.2 of the DSM framework, the Board will take on the coordination function of the EM&V process. The Board will work with both the gas utilities and stakeholders, as appropriate; to ensure that the operational characteristics of the programs will generate the data and information needed to undertake robust evaluations that will produce accurate results. Annual evaluations and audits will be conducted to verify to what extent the programs implemented by the gas utilities have delivered the expected results, and to inform future program design and delivery.

The components of the evaluation process are outlined below along with the general responsibilities of the respective parties:

- Evaluation Plan – responsibility of the gas utilities and a required component of DSM Plan filings. This document will inform the evaluation of the programs that will be coordinated by the Board.
- Draft Evaluation Report – responsibility of the gas utilities. This document will inform the larger review of program results coordinated by the Board.

- Independent Third Party Audit – Responsibility of the Board.
- Final Audit & Evaluation Report – responsibility of the third party Auditor. This report will provide final, audited and evaluation results related to the DSM programs delivered in the previous year and it will be coordinated by the Board.

The Board will set out the specific roles and responsibilities for the parties involved in the different steps of the evaluation and audit process in a future correspondence.

7.1.1 Evaluation Plan

The natural gas utilities' multi-year DSM Plan applications should include an Evaluation Plan. Approval of the natural gas utilities' DSM Plans will be conditional upon approval of an acceptable Evaluation Plan.

A key tenet of good program evaluation practices is for the utility to identify and document evaluation activities in an evaluation plan as part of the initial program design. This ensures that the operational characteristics of the program generate the data and information that can assist in the final program evaluation, including the development of data needed for the scorecard metrics. It further ensures that the evaluation effort can be adequately contemplated and resourced. This can be as simple as collecting relevant contact information as part of the operation of the program which will be used in follow-up activities, or more complicated activities such as pre- and post-implementation metering of equipment. In both cases, the evaluation techniques and parameters should be integrated with the design and operation of the program.

The Evaluation Plan should outline the natural gas utilities' proposed methodology to monitor the programs' impacts and to assess why those impacts occurred and how the program can be improved. More specifically, at a minimum, the Evaluation Plan should address the following:

- Key program evaluation metrics;
- Natural gas savings and other resource savings, as applicable;
- Results for each of the metrics on the program scorecard(s);
- Net Equipment and Program Costs;
- Cost-effectiveness results;
- Monitoring and collecting other relevant information (for example and where applicable: technology type, number of installations, customer address or location, delivery channel, participant incentive amount, benchmarking data, etc.);
- Informing decisions regarding LRAM and shareholder incentive amounts;

- Providing ongoing feedback, and corrective and constructive guidance regarding the implementation of programs; and,
- Assess whether there is a continuing need for the program and, if so, whether it should be expanded, reduced or maintained at the same scale.

It is the natural gas utilities' responsibility to ensure that the objectives listed above, plus any additional objectives determined appropriate, are addressed for all of their proposed DSM programs, including those delivered in partnership with electricity distributors and those delivered for the natural gas utilities by a third party under contract.
It is recognized that the level of effort required for monitoring and EM&V will change from year to year depending on the nature of the DSM programs undertaken and as a result of the flexibility of the DSM framework. It is also expected that more extensive review will be undertaken for those programs that account for the majority of expenditures and savings. Further, due to the nature of programs which deliver long-term savings and those that are dependent on longer-term natural gas usage levels, the Board acknowledges that monitoring and EM&V will need to be tailored appropriately to allow for proper evaluations of the results throughout the term of the new DSM framework, appreciating that results may not transpire in the year the program is delivered. The natural gas utilities are responsible for proposing the appropriate monitoring and EM&V requirements to reflect these program details in their Evaluation Plan. For custom projects, which usually involve specialized equipment, savings estimates should be assessed on a case-by-case basis, with the gas utility providing a clear indication of how it proposes these specific programs be evaluated. It is expected, as one part of the evaluation process, that each custom project will incorporate a professional engineering assessment of the savings. This assessment would serve as one supporting piece of documentation for the savings claimed. Additional evidence, such changes in actual usage before and after implementation of the DSM program, will further advance the accuracy and confidence of the results.

7.1.2 Draft Evaluation Report

The gas utilities should annually prepare a Draft Evaluation Report which should be filed with the Board or on before April 1st of the year following the program year. The Draft Evaluation Report should provide a clear compilation of the results achieved during each program year. The Draft Evaluation Report will be used to inform the Board on the natural gas utilities' year-over-year progress in the implementation of their multi-year DSM Plans by summarizing the savings achieved, budget spent and the preliminary evaluations conducted by the utilities in support of the draft results.

The Draft Evaluation Report should provide the annual and cumulative resource savings attributable to each program, presented as both net and gross of the adjustment factors (i.e., attribution, persistence, free riders and the spillover effects, if any). The gas utilities should include, as an appendix to their Draft Evaluation Report, the verifications studies provided by third party evaluators, and any other relevant research and evaluation documents.

The gas utilities should provide a statement that outlines the expected program year's lost revenue and shareholder incentive amounts that will be sought for approval, as well as the balance of the DSMVA that will be requested for disposition.

The gas utilities should also indicate in their Draft Evaluation Report what they have learned over the course of the program year. The goal of this section is to evaluate and benchmark programs for greater efficiency in delivery and cost-effectiveness, and to provide information to other utilities with respect to DSM programs. The gas utilities should indicate if a program is considered successful or not and whether the program should be continued. The Draft Evaluation Report should outline the activities planned for the subsequent year(s) (if applicable) and any planned modifications to program design or delivery.

The Draft Evaluation Report should also include information on the actual budget spent versus planned budget for the individual programs. Marketing or support programs (i.e., programs designed to enhance market acceptance of other programs) should not be reported individually as they are components of other programs. Rather, the costs of marketing or support programs should be allocated to the programs they support. Additional information that should be provided by the gas utilities in the Draft Evaluation Report can be found in Section 14.2 – Annual Evaluation Report Template.

7.1.3 Independent Third Party Audit

As outlined above, the Board will be responsible for selecting an auditor to assess the results of the natural gas utilities' DSM programs. The Board will strive to have an auditor hired by October 1st for the year to be audited[4]. This would enable the auditor to hire engineering firm(s) who will conduct verification studies, including custom project savings verifications ("CPSV") and the evaluation of other programs, as discussed further below.

[4] This process will begin in 2015 and be applicable to the 2015 DSM program year results.

At a minimum the Board expects the independent third party auditor will be asked to:

- Review the draft evaluation reports prepared by the gas utilities and verify the components of the draft program results;
- Conduct audits of DSM programs to ensure that the results proposed by the gas utilities are accurate;
- Confirm the calculations of savings and the draft evaluations conducted by the gas utilities are consistent with the evaluation plans approved by the Board;
- Provide an audit opinion on the DSMVA, lost revenues and shareholder incentive amounts proposed by the natural gas utilities and any subsequent amendments;
- Confirm any target adjustments have been correctly calculated and applied;
- Identify any input assumptions that either warrant further research or that should be updated with new best available information;
- Review the reasonableness of any verification work that has been undertaken by the gas utilities and included in the Draft Evaluation Reports;
- Recommend any forward-looking evaluation work to be considered; and,
- Prepare a Final Audit & Evaluation Report.

All program result evaluations will be conducted by the Board's third-party evaluator(s). The third-party evaluators will follow the Ontario Power Authority's ("OPA")[5] EM&V protocols, where applicable and relevant to the natural gas sector.[6]

The independent third party auditor is expected to take such actions by way of investigation, verification or otherwise, as are necessary, for the auditor to form its opinion. Custom projects should be audited using the same principles as any other programs. The third party auditor will be responsible for hiring and overseeing the CPSV work and responsible for undertaking a critical review of the utility savings estimates for custom commercial and industrial efficiency projects. The third party auditor will also be responsible for hiring a firm to conduct the appropriate evaluations of other programs as outlined in the approved Evaluation Plan.

Following receipt of the Draft Evaluation Report submitted by the gas utilities, the Board will instruct the auditor to prepare its scope of work that will guide the final evaluation and audit of the DSM program results. The auditor will then conduct their work and

[5] References to the OPA throughout this report should be considered to be references to the Independent Electricity System Operator ("IESO") for activities on and after January 1, 2015.
[6] The OPA's evaluation, measurement and evaluation documents can be found on the OPA's website at : http://powerauthority.on.ca/benefits/evaluation-measurement-and-verification

issue recommendations and proposed revisions for comment prior to the auditor finalizing the Audit & Evaluation Report.

7.1.4 Finalization of the Audit & Evaluation Report

After incorporating all relevant information, including recommendations and proposed revisions to the draft results, the auditor will finalize the Audit & Evaluation Report and submit to the Board. The Final Audit & Evaluation Report should include all relevant information regarding annual DSM program results. The Board will annually report on each utility's final results for its DSM programs. The Board expects that the utilities will use the results of the Final Audit & Evaluation Report when they file for disposition of their respective DSM deferral and variance accounts.

7.2 Adjustment Factors for Screening and Results Evaluation

To ensure that the energy savings that are the result of DSM programs truly reflect those which the gas utilities directly influenced, adjustments are made to the gross savings totals so that the savings totals remove other, non-utility effects that can affect the energy savings from DSM programs. Adjustments are also considered to accurately reflect the length of time energy savings from DSM programs remain in place, or persist. The exercise of adjusting energy savings results that transpire from the successful delivery of DSM programs is done to determine the final net savings and relies on the use of various adjustment factors which are discussed below.

The four adjustment factors described in this section are free ridership, spillover effects, attribution, and persistence.

The natural gas utilities should design and screen DSM programs using the best available information known to them at the relevant time, including information on adjustment factors. The natural gas utilities should continuously monitor new information and determine whether the design, delivery and set of DSM programs offered need to be adjusted based on that information.

7.2.1 Free Ridership and Spillover Effects

A free rider is a “program participant who would have installed a measure on his or her own initiative even without the program.”[7] In contrast, spillover effects refer to customers that adopt energy efficiency measures because they are influenced by a utility’s program-related information and marketing efforts, but do not actually participate in the program.

All adjustment factors considered, including free ridership and spillover effects, should be assessed for reasonableness prior to the implementation of the multi-year plan and annually thereafter, as part of the ongoing program evaluation and audit process for each natural gas utility. The natural gas utilities should always provide information on free ridership for all their applicable programs. In contrast, the natural gas utilities have the option to request the inclusion of spillover effects for any of their programs.

Any request for the Board to consider the spillover effects of a program, needs to be supported by comprehensive and convincing empirical evidence, which clearly quantify the spillover effects that a specific program has had on program savings and the natural gas utilities’ revenue.

For their custom projects, the natural gas utilities should propose common free ridership rates and spillover effects, if applicable, that are differentiated appropriately by market segment and technologies.

7.2.2 Attribution

Attribution relates to whether the effects observed after the implementation of a natural gas utility’s DSM activity can be attributed to that activity, or at least partly results from the activities of others.

Given the potential for greater coordination and integration of natural gas DSM programs with electricity CDM programs provided by rate-regulated electricity distributors, the guidance on attribution is divided into two categories: attribution between rate-regulated natural gas utilities and rate-regulated electricity distributors, and attribution between rate-regulated natural gas utilities and other parties (e.g., non-

[7] Violette, Daniel M. (1995) *Evaluation, Verification, and Performance Measurement of Energy Efficiency Programs*. Report prepared for the International Energy Agency.

rate-regulated entities such as agencies and various levels of government, non-rate-regulated private companies, etc.).

Attribution of Benefits Between Rate-Regulated Natural Gas Utilities and Rate-Regulated Electricity Distributors

For electricity CDM and natural gas DSM programs jointly delivered with rate-regulated electricity distributors, all the natural gas savings should be attributed to rate-regulated natural gas utilities and vice versa for electricity savings. This represents a continuation of the simplified approach adopted in the 2006 Generic Proceeding and continued in the 2012 DSM Guidelines.

Attribution of Benefits Between Rate-Regulated Natural Gas Utilities and Other Parties

Attribution of savings between rate-regulated natural gas utilities and other parties (e.g., governments, non-rate-regulated private sector, etc.) should be based primarily on the shares established in a partnership agreement reached prior to the program's launch.

Where the natural gas utilities' allocated share of natural gas savings in the partnership agreement is more than 20% of the share that would have been allocated based on a "percentage of total dollars spent" basis, an explanation for the difference should be provided.[8] The natural gas utilities are also expected to file expected spending for each of the partners participating in the delivery of the program before the program is launched and the actual amount spent by each partner within each program year has taken place. As partnerships do not always evolve as originally planned, this additional information will help the Board and stakeholders to assess the reasonableness of the shares allocated in the partnership agreement reached prior to the program's launch and the actual contribution the natural gas utilities made to the program.

The share allocated to the natural gas utilities will be used to determine the credited achievement for each of the relevant metrics used to evaluate the program.

[8] For example, if the partnership agreement allocates a share of 50% of the natural gas savings to the gas utility, but the actual share of "dollars spent" by the utility is 30% or less, an explanation should be provided to justify why the 50% share is more reflective of the gas utility's actual contribution.

7.2.3 Persistence

Persistence of DSM savings can take into account how long a DSM measure is kept in place relative to its useful life, the net impact of the DSM measure relative to the base case scenario, and the impact of technical degradation. For example, if an energy efficient measure with a useful life of 15 years is removed after only two years, most of the savings expected to result from that installation will not materialize. As for technical degradation, it refers to the potential for the DSM measure's performance to decrease as it gets closer to the end of its useful life (e.g., the achieved efficiency level of a natural gas furnace may decrease as it ages).

Another aspect that can be considered as part of the persistence factor is whether a program participant would have implemented the DSM measure on its own in the future (e.g., in two years), but their implementation date was accelerated by the program offering. In this case, the savings resulting from the DSM program would only accrue for up to the period by which the adoption was accelerated (e.g., two years), instead of the entire useful life of the measure.

Another important consideration in assessing the persistence of savings is the potential changes in usage pattern. For example, large custom commercial and industrial DSM projects with expected useful life of 20 years or more may not fully materialize if the business benefiting from the custom measure operates at lower levels or closes down its processes within that time period.

The natural gas utilities should provide a rationale for the persistence factor it has determined appropriate for each of its programs.

8.0 INPUT ASSUMPTIONS

8.1 Annual Process to Update Input Assumptions

Various assumptions are used at different stages of the multi-year DSM Plans. Assumptions such as operating characteristics and associated units of resource savings for a list of DSM technologies and measures are referred to as "input assumptions". What follows is a discussion about the specific components of the input assumptions. Gas utilities analyze the prospective programs and determine the benefits (e.g., total natural gas savings that can be achieved and the costs that can be avoided as a result of the DSM program) and compare them to the costs of delivering the program, including administration, marketing and education costs.

As part of the previous DSM framework, the Technical Evaluation Committee ("TEC") was established, comprised of representatives from the gas utilities, key stakeholders and independent experts, to develop a standard set of engineering assumptions related to the energy savings of different technologies and pieces of equipment, to be included in the master list of assumptions (the Technical Reference Manual ("TRM")), which is used by the gas utilities when designing and screening DSM programs. The TEC's role also includes administering any updates to the TRM on an annual basis to ensure that the standard set of energy efficient measures and assumptions reflect the best information available. The TRM is expected to be completed by the TEC by the middle of next year (i.e., 2015).

As discussed in the DSM framework at Section 8.2, the Board will coordinate the process to annually update the input assumptions for the new DSM framework. The Board's role with respect to coordinating any updates to the standard list of input assumptions would be complementary and related to its role in leading the evaluation process, also discussed in the DSM framework. The input assumptions will be updated regularly to reflect the relevant findings in the evaluation process. The Board's process will seek appropriate input, considerations and expertise from key stakeholders to inform future updates to the input assumptions.

8.2 Input Assumptions

Input assumptions will continue to cover a range of typical DSM activities, measures and technologies in residential and commercial applications. If applicable and practical, input assumptions for DSM activities, measures, and technologies for industrial applications could also be added. Input assumptions should generally be the same for each gas utility's DSM plan. On an exception basis, and to the extent required and supported, different input assumptions for the natural gas utilities may be provided to account for differences in their franchise areas. Estimated savings and costs of DSM programs will be defined relative to a frame of reference or "base case" that specify what would happen in the absence of the DSM program. At a minimum, the base case technology will be equal to, or more efficient than, the technology benchmarks mandated in energy efficiency standards, as updated from time to time. For example, in the case of a DSM program consisting of a residential programmable thermostat, the base technology may be a manual thermostat. For a program consisting of installing a high efficiency furnace, the base case equipment may be a furnace that meets the currently mandated efficiency standard. In practice, specifying savings relative to a frame of reference can be characterized by four general decision types:

- Early Replacement – a measure category where operable equipment is replaced by a higher efficiency alternative (also referred to as advancement)
- Natural Replacement – a measure category where the equipment is replaced on failure
- New Construction – efficiency measures in new construction or major renovations, whose baseline would be the relevant code
- Retrofit – a measure category that includes the addition of an efficiency measure to an existing facility such as insulation or control gaps (for example: to close hot air leaks through cracks and other gaps)

The evaluation of the achieved results for the purpose of determining the lost revenue adjustment mechanism ("LRAM") amounts and the shareholder incentive amounts should be based on the best available information which, in this case, refers to the updated input assumptions resulting from the evaluation and audit process of the same program year. For example, the LRAM and shareholder incentive amounts for the 2015 program year should be based on the updated input assumptions resulting from the evaluation and audit of the 2015 results. The updates to the input assumptions resulting from the evaluation and audit of the 2015 results would likely be completed in the second half of 2016.

Where feasible and economically practical, the preference to determine LRAM and shareholder incentive amounts should be to use measured actual results, instead of input assumptions. For example, it may be feasible and economically practical to measure the natural gas savings of weatherization programs based on the results of the pre- and post-energy audits conducted by certified energy auditors on a custom basis, as opposed to input assumptions associated with the individual measures installed.

9.0 COST-EFFECTIVENESS SCREENING

The purpose of screening natural gas DSM programs is to determine whether or not they should be considered any further for inclusion in the DSM portfolio. An appropriate screening test will include both utility system benefits and costs, and participant benefits and costs. Some programs, such as market transformation and pilot programs are not typically amenable to a mechanistic screening approach and, as set out in sections 6.5 and 6.2 respectively, should be reviewed on a case-by-case basis instead. Among the programs amenable to a mechanistic screening approach, the natural gas utilities may only apply for approval of programs that are cost effective as determined by the particular screening test.

The Board has determined that the natural gas utilities should screen prospective DSM programs using the Total Resource Cost-Plus ("TRC-Plus") test. The TRC-Plus test measures the benefits and costs of DSM programs for as long as those benefits and costs persist and applies a 15% non-energy benefit adder. Under this test, benefits are driven by avoided resource costs, which are based on the marginal costs avoided by not producing and delivering the next unit of natural gas to the customer. Those marginal costs avoided include the natural gas commodity costs (both system and customer) and transmission and distribution system costs (e.g., pipes, storage, etc.). The marginal costs also include the benefits of other resources saved through the DSM program, such as electricity, water, propane and heating fuel oil, as applicable. TRC-Plus test calculations are detailed in Section 9.1.3 below.

The natural gas utilities should also use the Program Administrator Cost ("PAC") test as a secondary reference tool to help prioritize programs that deliver the most cost-effective results. The PAC test measures the utility's avoided costs and the costs of DSM programs experienced by the utility system. Under this test, benefits are driven by avoided utility costs, including avoided energy costs, capacity costs, transmission and distribution costs and any other avoided costs incurred by the utility to provide its customers with natural gas services. The costs included in the PAC test calculation include all expenditures by the utility to administer DSM programs (i.e., costs to design, plan, administer, deliver, monitor and evaluate). The utilities should identify the programs that pass the TRC-Plus test but fail the PAC test and discuss the reasons the programs are still appropriate. PAC test calculations are detailed in Section 9.1.4 below.

For a prospective program to be deemed cost-effective, it must achieve a screening threshold benefit/cost ratio of 1.0 or greater. This shows that the benefits of the program are equal to or greater than the costs of the program. To recognize that low-income natural gas DSM programs may result in important benefits not captured by the TRC-Plus test, these programs should continue to be screened using a lower threshold value of 0.70. Low-income programs that fail to meet a TRC-Plus cost-benefit ratio of 0.7 can still be applied for by the gas utility. The Board will decide on these programs based on their merit.

The costs considered in the TRC-Plus test are the Net Equipment and Program Costs associated with delivering the DSM program to the market place.

9.1.1 Net Equipment Costs

Net Equipment Costs relate to the costs of the more efficient equipment relative to the base case scenario. They include capital, cost of removal less salvage value (e.g., in the case of a replacement), installation, operating and maintenance ("O&M"), and/or fuel costs (e.g., electricity) associated with the more efficient equipment. As the TRC-Plus test assesses the benefits and costs of DSM programs from the perspective of the utility and participant, it is does not differentiate between who (natural gas utility, customer, or third party) pays the cost of the equipment.

Net Equipment Costs can be either the cost difference between the more efficient equipment and a base measure (or the incremental cost) or the full cost of the more efficient equipment. When the investment decision is a replacement, the Net Equipment Costs will typically be incremental. For example, if a DSM program results in a high efficiency natural gas furnace being purchased instead of a standard model, the Net Equipment Costs would be incremental: they would be the cost differential between the two options. In contrast, retrofit and discretionary investments are typically associated with the full cost of the equipment. For example, if a DSM program results in a retrofit to improve the energy efficiency of an industrial process and, in the absence of such DSM program, the status quo would have been maintained, then the Net Equipment Costs will be the full cost of the equipment. As these examples illustrate, Net Equipment Costs depend not only on the equipment costs but also on the costs that would have been incurred under the base case (i.e., in the absence of the DSM program).

A third type of equipment cost is the cost of the equipment that is assigned to a project when a replacement decision is done early, or advanced, because of a natural gas utility's DSM programming efforts. Early replacements occur when an older, but still working lower efficiency technology, is replaced with a more efficient piece of equipment. In these cases, the natural gas utilities should adjust both the equipment life and the project cost to reflect the advancement. This adjustment is akin to a net present value estimate.

O&M costs associated with the more efficient equipment are often not incremental (i.e., they would have been incurred under the base case anyway). However, there are some exceptions where the incremental O&M costs are significant and these should be appropriately accounted for in the Net Equipment Costs. As a general rule, cost differential from the base case should be considered as part of the Net Equipment Costs for as long as they persist.

Free ridership and spillover effects, if applicable, should also be taken into account when calculating the Net Equipment Costs. A free rider is a "program participant who would have installed a measure on his or her own initiative even without the program."[9] In contrast, spillover effects refer to customers that adopt energy efficiency measures because they are influenced by a utility's program-related information and marketing efforts, but do not actually participate in the program. Net Equipment Costs associated with free riders are excluded from the TRC test.[10] However, as discussed in the section 3.2.2, all Program Costs associated with free riders should be included in the TRC analysis.

Spillover effects are essentially the mirror image of free ridership. Net Equipment Costs associated with spillover effects are included in the TRC-Plus test.[11] However, as discussed below in section 9.1.2, there are no Program Costs associated with spillover effects.

Information sources for equipment costs vary. For residential equipment, retail store prices are appropriate sources of information for many technologies including appliances and "do-it-yourself" water heater or thermal envelope upgrades. It is common practice to specify an average price based on a sample of retail prices. For utility direct/install programs, it is appropriate to use the cost to the utility of bulk purchase of the equipment. For commercial and industrial equipment, cost data can be more complicated to acquire due to limited access and confidentiality concerns. For larger "custom" projects, invoices or purchase orders may be necessary to support the cost estimate. Net Equipment Cost estimates should be based on the best available information known to the natural gas utilities at the relevant time.

9.1.2 Program Costs

For the purpose of the TRC-Plus test, the Program Costs relate to DSM program include the following components:

i) Development and Start-up;
ii) Promotion;
iii) Delivery;
iv) Evaluation, Measurement and Verification ("EM&V") and Monitoring; and
v) Administration.

[9] Violette, Daniel M. (1995) *Evaluation, Verification, and Performance Measurement of Energy Efficiency Programs*. Report prepared for the International Energy Agency.
[10] Eto, J, (1998) *Guidelines for assessing the Value and Cost-effectiveness of Regional Market Transformation Initiatives*. Northeast Energy Efficiency Partnership, Inc.
[11] Ibid.

Of the above costs, only Start-up, Promotion, Delivery, some Evaluation and Verification are applicable to individual programs. Other costs related to the design and the delivery of DSM programs are appropriately considered at the DSM portfolio level. These include Development, some Evaluation costs, and Monitoring, Tracking and Administration costs.

Incentive costs are not included in Program Costs. Incentive costs may include cash incentives, in-kind contributions and/or tax benefits provided to participants to encourage the implementation of a DSM measure. Incentive costs are a transfer from a program-sponsoring organization to participating customers and consequently do not impact the net benefits or costs. As the TRC-Plus test assesses the benefits and costs of DSM programs, it is does not differentiate between who (natural gas utility or third party) pays for the Program Costs. Program Costs components are further explained below.

i) Development and Start-up Costs

DSM programs may involve start-up costs at the early stages of a DSM program's life. For example, there may be costs incurred to train a natural gas utility's staff in the use of the DSM program's equipment or techniques. In general, start-up costs are only a small component of the total costs in the life cycle of a DSM program.

ii) Promotion Costs

Promotion costs may be incurred to educate the customer about a DSM program and will vary by program type and level of promotional effort. The cost of promotion depends on the method employed, the market segment and the DSM measures promoted.

As noted above, incentive costs are not included in Program Costs since they do not impact the net benefit or cost.[12]

[12] For clarity, while incentive costs are not included in the TRC-Plus test, incentive costs should be included in and reported as part of the gas utility's DSM program budget.

iii) Delivery Costs

Program delivery costs include any natural gas utility's devices needed to operate the programs such as specialized software or tools.

iv) EM&V and Monitoring Costs

There are two broad categories of evaluation activity: impact evaluation and process evaluation. Impact evaluation focuses on the specific impacts of the program – for example, savings and costs. Process evaluation focuses on the effectiveness of the program design – for example, the delivery channel. Some of these costs will be assigned directly to a specific program or multiple programs, while a portion of the costs are more appropriately assigned across all programs (i.e., at the DSM portfolio level).

EM&V and monitoring costs are incurred for systems, equipment and studies necessary to track measurable levels of program success (e.g., number of participants/installations, natural gas savings, Net Equipment Costs and Program Costs) as well as to evaluate the features driving program success or failure.

v) Administrative Costs

Administrative costs are generally the costs of staff who work on DSM activities. These costs are often differentiated between support and operations staff. Support staff costs are considered fixed costs or "overhead" that occur regardless of the level of customer participation in the programs. Operations staff costs are variable, depending on the level of customer participation. The natural gas utilities should include all staff salaries that are attributable to DSM programs as part of their Program Costs. For practical purposes, if certain administrative costs cannot be assigned to individual programs these costs should be accounted at the portfolio level.

Program Costs should be considered as part of the TRC-Plus test for as long as they persist (e.g., monitoring and EM&V costs may be spread over a period of time). Free ridership and spillover effects, if applicable, should also be taken into account when calculating the Program Costs.

All Program Costs associated with free riders should be included in the TRC-Plus analysis. Programs that have high free ridership rates will be less cost effective (as measured by the TRC-Plus test) since their Program Costs will be included in the analysis while their benefits will not.

The spillover effects are associated with customers that adopt energy efficiency measures because they are influenced by a utility's program-related information and marketing efforts, but do not actually participate in the program. Accordingly, there are no Program Costs associated with the spillover effects.[13] If the spillover effects are considered and adequately supported, then programs that have high spillover rates will be more cost effective (as measured by the TRC-Plus test) since they do not have Program Costs while they generate benefits.

Program Cost estimates should be based on the best available information known to the natural gas utilities at the relevant time.

9.1.3 TRC-Plus Test Calculation

For screening purposes, the TRC-Plus test should be performed at both the program and portfolio level.

At the program level, the TRC-Plus test takes into account the following:

- Avoided Costs;
- Net Equipment and Program Costs;
- Adjustments to account for free ridership, spillover effects, and persistence of savings and costs, as applicable; and,
- A 15% non-energy benefit adder.

The results of the TRC-Plus test can be expressed as a ratio of the present value ("PV") of the benefits to the PV of the costs. For example, the PV of the benefits consists of the sum of the discounted benefits accruing for as long as the DSM program's savings persist. The PV of the benefits therefore expresses the stream of benefits as a single "current year" value.

If the ratio of the PV of benefits to the PV of the costs (the "TRC-Plus ratio") exceeds 1.0, the DSM program is considered cost effective as it implies that the benefits exceed the costs. If, on the contrary, the TRC-Plus ratio for a program falls below 1.0, the

[13] An alternative way to explain this is that all Program Costs are allocated to program participants (including free riders) and there are no additional Program Costs generated by the spillover effect.

program would be screened out and no longer considered for inclusion as part of the DSM portfolio.[14]

To provide the Board with an appropriate amount of information regarding cost-effectiveness, all programs should be screened with the TRC-Plus test. The TRC-Plus threshold test should be normally 1.0 for all programs amenable to this screening test, except for low-income programs. However, the Board understands that some programs, although beneficial when reviewed from a broader perspective, may not pass a cost-effectiveness screening threshold of 1.0. The Board will consider these programs on a case-by-case basis. To recognize that all programs may not pass the TRC-Plus test, the utility should ensure its overall DSM portfolio has a TRC-Plus ratio of 1.0 or greater. Further, since low-income natural gas DSM programs may result in important benefits not captured by the TRC-Plus test, these programs should be screened using a lower threshold value of 0.70 instead, but also may be considered at a lower threshold.

The TRC-Plus ratio is expressed mathematically below:

$$\textit{TRC-Plus Ratio} = \frac{PV_{Benefits}}{PV_{Costs}}$$

Where:

$$PV_{Benefits} = \left(\sum_{t=1}^{N} \frac{UAC_t + TC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at} + PAC_{at}}{(1+d)^{t-1}} \right) * (1+15\%)$$

$$PV_{Costs} = \sum_{t=1}^{N} \frac{PRC_t + PCN_t + UIC_t}{(1+d)^{t-1}}$$

And where,

UAC_t = Utility avoided supply costs in year t (see section 10.0)
Avoided costs should be calculated using the input assumptions, savings estimates, and adjustment factors based on the best available information known to the natural gas utilities at the relevant time, as further described in

[14] An alternative way to consider the cost-effectiveness of a program under a TRC-Plus ratio threshold of 1.0 is to determine whether the TRC-Plus net savings are greater than 0. The TRC-Plus net savings are equal to the PV of benefits less the PV of costs.

		section 8.0 and 7.2.
UAC_{at}	=	Utility avoided supply costs for the alternate fuel in year t
TC_t	=	Tax credits in year t
PAC_{at}	=	Participant avoided costs in year t for alternate fuel devices
PRC_t	=	Program Administrator program costs in year t (see section 9.1.4) Program Costs should be calculated using cost estimates and adjustment factors based on the best available information known to the natural gas utilities at the relevant time, as further described in sections 9.1.4 and 7.2.
PCN_t	=	Net Participant Costs
UIC_t	=	Utility increased supply costs in year t (see section 9.1.1) Utility supply costs should be calculated using cost estimates and adjustment factors based on the best available information known to the natural gas utilities at the relevant time, as further described in sections 9.1.1 and 7.2.
N	=	Number of years that the savings are expected to persist or that the incremental costs are expected to be incurred, whichever is greater. (see section 7.2.3)
d	=	Discount rate (see section 10.0)

9.1.4 PAC Test Calculation

The PAC Test should also be used by the gas utilities when screening potential programs, but should be used at the portfolio level as a tool to help prioritize programs. The PAC Test measures the net costs of a DSM program as a resource option based on the costs incurred by the program administrator (including incentive costs) and excluding any net costs incurred by the participant. The benefits are similar to the TRC-Plus benefits. Costs are defined more narrowly.

The PAC test is described by the following equation:

PAC test net benefit ($) = PV avoided supply cost – (PV incentive cost + PV program cost)

Or (to determine net benefit as a ratio):

PAC Test (ratio) = PV avoided supply cost/(PV incentive cost + PV program cost)

The PAC Test is expressed mathematically below:

$$PAC\ Ratio = \frac{PV_{Benefits}}{PV_{Costs}}$$

Where:

$$PV_{Benefits} = \sum_{t=1}^{N} \frac{UAC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$PV_{Costs} = \sum_{t=1}^{N} \frac{PRC_t + INC_t + UIC_t}{(1+d)^{t-1}}$$

And where,

UAC_t	=	Utility avoided supply costs in year t (see section 10.0) Avoided costs should be calculated using the input assumptions, savings estimates, and adjustment factors based on the best available information known to the natural gas utilities at the relevant time, as further described in section 8.0 and 7.2
UAC_{at}	=	Utility avoided supply costs for the alternate fuel in year t
PRC_t	=	Program Administrator program costs in year t (see section 9.1.4) Program Costs should be calculated using cost estimates and adjustment factors based on the best available information known to the natural gas utilities at the relevant time, as further described in sections 9.1.4 and 7.2
INC_t	=	Incentives paid to the participant by the sponsoring utility in year t. First year in which cumulative benefits are greater than cumulative costs.
UIC_t	=	Utility increased supply costs in year t (see section 9.1.1) Utility supply costs should be calculated using cost estimates and adjustment factors based on the best available information known to the natural gas utilities at the relevant time, as further described in sections 9.1.1 and 7.2.
N	=	Number of years that the savings are expected to persist or that the incremental costs are expected to be incurred, whichever is greater. (see section 7.2.3)
d	=	Discount rate (see section 10.1)

10.0 AVOIDED COSTS

Assumptions relating to the benefit of not having to provide an extra unit of supply of natural gas, or other resources (e.g., electricity, heating fuel oil, propane or water) through the delivery of DSM programs are referred to as “avoided costs”.

Avoided costs should be based on long-term estimates and include:

- Avoided supply-side and delivery costs, such as capital for distribution infrastructure, operating and commodity costs[15].
- Avoided demand-side costs, such as the impact on customer equipment and operating costs.
- The following avoided upstream costs directly incurred by the natural gas utility: storage costs, transportation tolls and demand charges[16].

Each natural gas utility should calculate all avoided costs to reflect their specific cost structure as well as the characteristics of their franchise area. In order to ensure consistency, the natural gas utilities should use a common methodology to determine their utility-specific avoided costs. The natural gas utilities should also coordinate the timing for selecting commodity costs so that they are comparable.[17]

The estimation of natural gas avoided costs should consider whether different estimates are warranted for each customer class, sector (e.g., residential, commercial, and industrial), and/or the load characteristics (e.g., baseload versus weather sensitive).

In determining their utility-specific avoided costs, the natural gas utilities should consider, among other information available, the avoided costs used by the OPA to assess the cost effectiveness of electricity CDM programs.[18]

10.1 Discount Rate

For the purpose of cost-effectiveness tests (i.e., TRC-Plus, PAC, etc.), the total avoided costs resulting over the life of the DSM measures need to be discounted to a present value. Traditionally, the natural gas utilities have used a discount rate that is equal to their Board approved weighted average cost of capital ("WACC"). The Board is of the view that the gas utilities should use a discount rate (real) of 4% when screening prospective DSM programs to determine if they are cost-effective for consideration s part of the new 2015 to 2020 multi-year DSM plan. This discount rate is consistent with

[15] Commodity costs include those for natural gas and, if applicable, for other resources such as electricity, water, heating fuel oil and propane.
[16] For simplicity, other avoided upstream costs (such as avoided costs of upstream pipeline companies and natural gas producers) should be excluded from the avoided cost calculations.
[17] Commodity costs include those for natural gas and, if applicable, for other resources such as electricity, water, heating fuel oil and propane.
[18] The avoided cost assumptions currently used by the OPA are provided in the *OPA Conservation and Demand Management Cost Effectiveness Guide*, dated October 15, 2010.

that used in the electricity Conservation First framework ensuring that all possible energy conservation programs are screened in a consistent manner.

10.2 Prioritization of Programs

To the extent that not all candidate programs that have passed the screening tests can be undertaken due to resources or rate impact considerations, a flexible prioritization approach should be used to take into account the iterative nature of DSM portfolio design. This flexible prioritization approach should also take into account:

- Programs that will result in long-term natural gas savings
- Programs that will prevent lost opportunities
- Programs that will defer future capital infrastructure investments
- Programs that will be coordinated and integrated with electricity CDM programs
- Programs that are evidenced-based and rely on detailed customer data in order to clearly show a customer has lowered consumption levels over the course of different billing periods
- Programs that have high PAC score
- Programs that are key priorities within the DSM framework

The gas utilities should also rely on information they receive through their stakeholder engagement process and the requirements of the overall DSM framework, namely the long-term natural gas savings targets when deciding what programs to include in their DSM portfolios.

11.0 ACCOUNTING TREATMENT: RECOVERY AND DISPOSITION OF DSM AMOUNTS

Consistent with past practices, recovery and disposition of DSM related amounts (i.e., DSM Variance Account (“DSMVA”), DSM Incentive Deferral Account (“DSMIDA”), and LRAM Variance Account (“LRAMVA”)) will be filed by the natural gas utilities annually, based on the actual amount of natural gas savings resulting from the utilities’ DSM programs in relation to the annual plans targets. The DSM amounts include program spending, shareholder incentive amounts and lost revenues in relation to the DSM programs delivered by the natural gas utility. Further, lost revenues will not act as a disincentive to the natural gas utilities’ delivery of DSM programs. When implementing DSM, lost revenues indicates successful DSM programs where customers’ consumption have been reduced, thus reducing natural gas utilities’ revenue.

Financial and accounting elements related to the gas utilities' DSM Plans (e.g., budget,, shareholder incentive structure, LRAM, DSMVA) will be established at the outset of a multi-year DSM Plan with the intention of applying the same process throughout the duration of the multi-year DSM Plan. However, although the process for recovery will be developed and established at the outset of the DSM term, the DSM Plan components will all be delivered and measured on an annual basis within the multi-year DSM term. Therefore, the amounts in all DSM variance or deferral accounts should be recorded on an annual basis.

The natural gas utilities should use a fully allocated costing methodology for all their DSM activities. Capital assets (property, plant and equipment) associated with the multi-year DSM Plan will be included in rate base, and will be treated in the same manner as distribution assets. DSM expenses incurred should be expensed in the normal course of the utility's operations.

Cost allocation in rates should be on the same basis as budgeted DSM spending by customer class. This allocation applies to both direct and indirect DSM program costs.

Any assets purchased with funds from third parties (i.e., not funded through distribution rates) will not be eligible for inclusion in rate base, nor will there be any distribution rate recovery of ongoing operating costs associated with the asset, or income taxes payable in relation to third-party funded activities. Likewise, DSM expenses funded by third parties should not be included in the natural gas utility's distribution accounts. The accounting treatment of DSM spending not funded through distribution rates is further discussed in section 11.6 below.

The natural gas utilities should apply annually for the disposition of any balances in their LRAMVA and DSMVA and, if applicable, apply for a shareholder incentive amount associated with the previous DSM program year and disposition of any resulting DSMIDA balance.

This application should include the final results as outlined in the Final Evaluation and Audit Reports, and information setting out the allocation across rate classes of the balances in the LRAMVA, DSMVA and DSMIDA.

11.1 Revenue Allocation

Any net revenues generated by a shareholder incentive for distribution rate-funded DSM should be separate from (i.e., not used to offset) the natural gas utilities' distribution revenue requirement.

11.2 Demand-Side Management Variance Account ("DSMVA")

This account should be used to track the variance between actual DSM spending by rate class versus the budgeted amount included in rates by rate class. The natural gas utility should apply annually for disposition of the balance in its DSMVA, together with carrying charges, after the completion of the annual third party audit (see section 7.1.3).

The actual amount of the variance versus budget targeted to each customer class will be allocated to that customer class for rate recovery purposes. If spending is less than what was built into rates, ratepayers will be reimbursed for the full amount. If more is spent than was built into rates, the natural gas utility may be reimbursed up to a maximum of 15% above its DSM budget for the year. All additional funding beyond the annual DSM budget must be utilized on incremental program expenses only (i.e. cannot be used for additional utility overheads).

The option to spend 15% above the approved annual DSM budget is meant to allow the natural gas utilities to aggressively pursue programs which prove to be very successful. Accordingly, the natural gas utility will be permitted to recover from ratepayers up to 15% above its annual DSM budget recorded in its DSMVA provided that:

A) It had achieved its weighted scorecard target(s) (i.e., 100%) on a pre-audited basis for the program(s) prior to additional spending being made on those programs; and

B) The DSMVA funds were used to produce results in excess of those targets (i.e., in excess of 100%) on a pre-audited basis.

C) The DSMVA funds were used in 2015 to begin implementing the key priorities outlined in the DSM framework during the transition to the gas utilities' new multi-year DSM plans. This level of funding is incremental to any DSMVA amounts used in relation to (A) or (B) above after 100% of weighted scorecard targets are met.

When applying for disposition of its DSMVA account, the natural gas utility will have to provide evidence demonstrating the prudence and cost effectiveness of the amounts spent in excess of the approved annual DSM budget. In considering the prudence of any spending in excess of an approved annual budget, the Board will consider the information available to the natural gas utility at the time the program was implemented.

11.3 LRAM Variance Account ("LRAMVA")

The LRAMVA should be used to track, at the rate class level, the actual impact of DSM activities undertaken by the natural gas utility from the forecasted impact included in distribution rates. A natural gas utility may only record an LRAM amount in relation to DSM activities undertaken within its franchise area by itself and/or delivered for the natural gas utility by a third party under contract.

The natural gas utilities should calculate the full year impact of DSM programs on a monthly basis, based on the volumetric impact of the measures implemented in that month, multiplied by the distribution rate for each of the rate classes in which the volumetric variance occurred[19]. LRAM amounts are only accruable and thus only recorded in the variance account until such time as the Board sets distribution rates for the utility based on a new load forecast.

The LRAM amount is recovered in rates on the same basis as the variances in distribution revenues were experienced at the rate class level. The LRAM therefore results in a true-up for each rate class. The natural gas utilities should apply annually for disposition of the balance in their LRAMVA, together with carrying charges, after the completion of the annual third party audit (see section 7.1.3).

11.4 DSM Incentive Deferral Account ("DSMIDA")

The purpose of the DSMIDA is to record the shareholder incentive amount earned by a natural gas utility as a result of its DSM programs. This account will come into effect at the beginning of the term of the multi-year DSM Plan. The natural gas utilities should apply annually for disposition of the balance in their DSMIDA, together with carrying charges, after the completion of the annual third party audit (see section 7.1.3).

Shareholder incentive amounts will be available in relation to the verified savings outlined in the Final Evaluation and Audit Reports. In some instances, for programs of a particular nature (e.g., benchmarking programs), natural gas savings results may not be available in the year the program was delivered. For these programs shareholder incentives will be awarded when the evaluation results become available.

Incentive amounts paid to the natural gas utilities should be allocated to rate classes in proportion of the amount actually spent on DSM activities on each rate class.

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[19] Union 2014-2018 IRM (established in EB-2013-0202) states that LRAM is only applicable to the contract rate classes.

11.5 Carbon Dioxide Offset Credits Deferral Account

The purpose of this account, as established in the 2006 Generic Proceeding, is to record amounts representing the proceeds resulting from the sale of or other dealings in earned carbon dioxide offset credits.

11.6 DSM Activities Not Funded Through Distribution Rates

Any third-party funding for DSM activities (as opposed to rate-funded DSM activities) should be classified as Non Rate-Regulated Activities. Consequently, the financial records associated with third-party funding should be separate from those associated with the natural gas utilities' distribution activities.

A natural gas utility receiving third-party DSM revenues and incurring related DSM expenses and/or capital expenditures should record these transactions in separate non-utility distribution accounts in the Uniform System of Accounts for Gas Utilities. For this purpose, Account 312, Non-Gas Operating Revenue, should be used to record these revenues and Account 313, Non-Gas Operating Expense, should be used to record these expenses. Sub-accounts may be used as appropriate to segregate these DSM activities from other Non-Rate Regulated Activities.

12.0 INTEGRATION & COORDINATION OF NATURAL GAS DSM AND ELECTRICITY CDM PROGRAMS

In order to provide customers with a better overall program experience, the Board expects gas utilities to work closely with electricity distributors and the OPA in coordinating and integrating their proposed DSM programs for 2015 to 2020. By doing so, the Board expects the gas utilities to achieve greater efficiencies in a number of program areas, including design, delivery, marketing, and education. Applications for proposed DSM programs should provide evidence that consideration has been given to the elements of the proposed DSM programs that are currently included in a CDM program and how these elements can and have been integrated in the proposed DSM program. A discussion of the associated benefits should also be provided. The gas utilities should continue to work with the OPA and monitor the developments of the Conservation First Framework with respect to coordination and integration of DSM and CDM programs going forward.

13.0 FUTURE INFRASTRUCTURE PLANNING ACTIVITES

As discussed in Section 13 of the DSM framework, the gas utilities should provide a clear indication on how they will study the effects that DSM can have on deferring, postponing or reducing future capital investments. The Board is of the view that this analysis is necessary in order for the gas utilities to effectively develop a specific plan to identify the opportunities to implement DSM programs that may be able to address infrastructure planning needs at the regional and local levels. The Board expects that the gas utilities will need to update their long-term system planning processes and analysis to ensure that DSM is included as a component going forward. This should ensure that consideration of the positive effects of DSM can be appropriately factored into proposals for future capital investments far enough in advance for DSM to be considered as a practical alternative.

14.0 FILING REQUIREMENTS

In addition to the guidance provided throughout this document, the natural gas utilities' multi-year DSM Plan applications, and any request for changes thereof, should be guided by the information below.

The natural gas utilities are expected to follow the filing and reporting requirements outlined in these DSM Guidelines at a minimum. In all instances, the natural gas utilities are responsible for ensuring that all relevant information is before the Board and are expected to make their best efforts to provide filings in a consistent manner.

14.1 Filing of Multi-year DSM Plan

The natural gas utilities should coordinate the filing date of their DSM plans and file with the Board at the same time. This will enable both gas utilities' DSM Plans to be heard by the same panel of the Board to ensure that common issues are addressed similarly and adjudicated in an efficient manner.

Within the DSM plans, the gas utilities should ensure that the budget figures provided include all relevant DSM program costs including estimates for administration, evaluation and monitoring, research (including any planned market potential studies and/or update(s) thereof or studies related to incorporating DSM into infrastructure planning), support, and stakeholder engagement.

The multi-year DSM plan application should also include:

1. Characteristics of a natural gas utility's distribution system, including:

a) Total natural gas purchases;
b) Sales by rate class; and,
c) Number of customers by rate class,
d) Summaries of sales and number of customer figures for all rate classes within the various customer types (e.g., residential, low-income, commercial, industrial and large volume) that DSM programs will be developed for and offered to.

2. Discussion and detailed plan for how the gas utility plans to meet its annual and long-term natural gas savings targets, including:

    a) Annual targets;
    b) Proposed total and annual budgets with justification for amounts; and,
    c) Transition plan for how the gas utility will incorporate new programs and address the key priorities of the DSM framework.

3. For each program, the following information should be provided:

    a) Detailed description of the program;
    b) Customer type(s) (e.g., residential, low-income, commercial, industrial) and rate class(es) targeted;
    c) Analysis of the programs from the customer perspective, including simple payback period calculations before and after the financial incentive is provided;
    d) Analysis of major barriers within customer segments for all proposed programs and how the gas utility plans to overcome these barriers;
    e) Projected annual incremental natural gas savings as well as other resource savings, if applicable;
    f) Goals, including program metrics and scorecards;
    g) Maximum shareholder financial incentive allocated to the program
    h) Length;
    i) Projected budget, listing:
        i) Description of the primary barriers preventing higher uptake of the measures of the program;
        ii) Description of how the program will remove the barriers;
        iii) Capital expenditures per year;
        iv) Operating expenditures per year separated into direct and indirect expenditures;
        v) For each direct operating expenditure, an allocation of the expenditure by targeted customer classes; and,
        vi) Expenditures for draft evaluation and monitoring of the program.

4. Program cost-effectiveness results;

    a) The input assumptions underlying the forecasted savings and costs including a detailed presentation of the calculations;
    b) Where a program involves the implementation of specialized equipment or technology not identified in the Board approved list of input assumptions, the natural gas utilities should provide their own values, if available, and report all other relevant information;
    c) A statement as to whether the natural gas utility has varied from the Board approved list of input assumptions. Where the natural gas utility has varied from that list, the natural gas utility should provide detailed evidence to support the alternative data;
    d) Estimated Net Equipment and Program Costs; and,
    e) The benefit-cost analysis, calculating the TRC-Plus net savings and TRC-Plus ratio of the program and the PAC ratio for all programs, including how the natural gas utility has prioritized the programs proposed in its DSM Plan.

5. The natural gas utilities should also provide the following (specified on a per year basis):

    a) The total amount of DSM spending to be recovered in rates and the allocation of those costs, both to the specific rate classes as well as to the general customer types (e.g., residential, low-income, commercial, industrial, large volume) that will benefit from the DSM program applied for;
    b) A forecast of the number of customers in each class and a forecast of m^3 of natural gas to be used as a charge determinant for the rate rider of each rate class to benefit from the DSM program(s); and,
    c) A comparison of the proposed rates with and without the DSM rate rider for the rate year in question, inclusive of all budget amounts and potential maximum shareholder incentives amounts for all rate classes.

6. An Evaluation Plan, in accordance with section 7.1.1.

7. In addition to the information above, the following information should be provided for pilot programs (see section 6.2):

    a) A description of the technology being used;
    b) A discussion of whether and how, to the natural gas utilities' knowledge, the technology is being or has been used or tested by any other utilities. Where the

technology is being used by another natural gas utility, a description of how the natural gas utilities will coordinate or work with the other natural gas utility using or testing the technology to ensure effective use of the program and of lessons learned; and

c) The expected outcome of the pilot program. That is, what data or information will the program produce, and how will it be used for future DSM programs.

14.2 Annual Reporting – Annual Evaluation Report Template

To enable consistent and efficient reporting, the Board is of the view that the gas utilities should work together, in coordination with Board staff, to develop a DSM Annual Evaluation Report template which will be used consistently by both gas utilities when preparing both the Draft and Final Evaluation Reports. The Draft Evaluation Report template will be submitted to the Board by April 1st of each year as discussed in Section 7.1.2 above and then be used by the third party auditor, and updated and finalized by the utilities to reflect the recommendations of the auditor. At a minimum, the Evaluation Report template should include the following key elements, in a clear and concise manner, at the beginning of the report:

- Annual and long-term DSM budgets ($/year, and $/6 years);
- Actual annual total DSM costs (including DSM budget, overheads, evaluation, shareholder incentive, lost revenues) for each rate class dating back to 2007;
- Historic actual annual DSM spending ($/year) dating back to 2007;
- DSM spending as a percent (%) of distribution revenue[20];
- Historic annual shareholder incentives amounts available and earned ($/year) dating back to 2007;
- Shareholder incentive earned as a percent (%) of DSM budget;
- Annual and long-term natural gas savings targets (m^3/year, and m^3/6 years);
- Total annual and cumulative gross and net natural gas savings(m^3) for each year of the DSM framework (2015 to 2020);
- Total historic annual and cumulative gross and net natural gas savings (m^3) dating back to 2007;

[20] Distribution revenue for the two utilities should be: For Union Gas Limited: equal to gas distribution margin and be the gas sales and distribution revenue less the cost of gas where gas sales and distribution revenue is the sum of the delivery revenue and gas supply revenue (and earning sharing, if applicable). For Enbridge Gas Distribution Inc.: equal to gas distribution margin and be the gas commodity and distribution revenue plus transportation of gas for customers less the cost of gas, which includes gas commodity and distribution costs, excluding depreciation.

- Total annual and cumulative gross and net natural gas savings (m^3) from 2007 to the reporting year as a percent of total annual natural gas sales[21];
- Actual annual gas operating revenue[22] ($/year);
- Actual annual operating revenue less cost of natural gas commodity ($/year);
- Total cost of gas ($ million/year);
- Total natural gas sales (m^3/year); and,
- Number of customers, broken out by rate class and by customer type (i.e., residential, low-income, commercial and industrial, relative to the DSM programs offered by the gas utility) per year.

In addition to the information listed above, the gas utilities should also include all relevant annual DSM program information outlined in Section 7.1.2.

[21] Total annual natural gas sales should be total throughput (m^3) of the rate classes subject to DSM costs as reported in the gas utilities' annual deferral disposition filings with the Board and represent all distribution volumes from those rate classes subject to DSM costs (not weather normalized).
[22] Operating revenue figures should be taken from publicly available financial reports.