# Draft Filing Guidelines to the Demand Side Management Framework for Natural Gas Distributors

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# 1. INTRODUCTION

The DSM Filing Guidelines DSM Filing Guidelines is a companion document to the 2015-2020 DSM Framework. It is intended to provide a common understanding of key elements of DSM activities and outline the specific information the Board expects the natural gas utilities to take into consideration in developing their DSM Plans and filing applications. The sections below may provide further details to the related sections discussed in the DSM Framework.

# 2. PROGRAM TYPES

As discussed in Section 7.0 of the DSM Framework, the Board expects the gas utilities to transition their DSM activities over the course of the new DSM Framework to focus on key priorities outlined by the Board. As part of this transition, and in addition to that outlined in Section 7.0 of the DSM Framework, the Board expects that the gas utilities will explore and include information on how they plan to incorporate the following elements and new program types into their DSM Plans:

**i) provide financial incentives so customers can pursue energy efficient upgrades that will deliver natural gas savings over the long-term;**

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. By focusing on 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.

**ii) extend programs for low-income consumers across the province;**

The Board is of the view that the current low-income programs should be available to low-income natural gas consumers across the province 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 2.6.

**iii) provide expert, value-added technical advice through energy management services;**

The gas utilities should have programs to provide customers, especially large volume customers that are more sophisticated, with technical advice that enhances the customer's internal energy management processes and provides the customer with a value-added resource.

**iv) 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 of customer-specific natural gas usage information available to a customer, they are able to better take advantage of available energy efficient technologies and manage their energy usage.

**v) benchmark energy usage to enable detailed data analysis and comparison of usage with other 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 others customers of similar characteristics – either those in their neighborhood or town/city, or other households or workplaces 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 new DSM framework.

**vi) investigate on-bill financing for conservation measures; and,**

In order to allow for a greater number of customers to participate in DSM programs, the gas utilities should explore how to provide various options related to financing energy efficiency upgrades. Since the costs for thermal envelope improvements or to replace major home and business technologies such as a furnace or hot water heaters can be substantial, in order to encourage more customers to upgrade to more efficient equipment, it may be reasonable for the gas utilities to offer a financing option, displayed directly on the natural gas bill, to qualified customers. In developing on-bill financing programs, the gas utilities are expected to survey other jurisdictions that offer a similar type of program and build off of past successes.

vii) **integrate and coordinate DSM programs with electricity conservation 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.

## 2.1 DSM Programs with Long-Term Natural Gas Savings

A central component of the gas utilities' new DSM Plans should be a 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.

## 2.2 Infrastructure Planning Related Programs

Gas utilities should also provide a clear indication on how they will study the effects that DSM can have on deferring or postponing capital investments in order to develop a specific plan for how and when they will implement DSM programs 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 an appropriate level of advance consideration of the positive effects of DSM can be factored into proposals for future capital investment planning.

## 2.3 Coordination and Integration with 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 Ontario Power Authority ("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.

## 2.4 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 such as on- bill financing 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. 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.

## 2.5 Programs for Large Volume Customers

The Board continues to be of the view that programs designed for large volume customers are not mandatory. If a gas utility deems it appropriate to offer a program for its large volume customers, the primary focus of the program(s) should be providing value-added, technical expertise to customers, including engineering studies on how the customer can more efficiently use their current energy systems and identify areas of efficiency improvements. Further, the Board is of the view that the nature of the programs designed and delivered to large volume customers offer the gas utilities possibilities to coordinate and integrate their efforts with electricity distributors as these customer's facilities typically use both energy sources.

## 2.6 Low-Income Programs

The purpose of DSM programs tailored to low-income consumers is to recognize that, although these programs may result in lower TRC net savings than similar non-low-income DSM programs, they also result in various other benefits that are difficult to quantify. These programs also more adequately address the challenges involved in providing DSM programs for, and the special needs of, this consumer segment.

Low-income programs are a set of resource acquisition and market transformation programs designed for, and targeted to, low-income customers. 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. Any updates required to the low-income program requirements and eligibility criteria listed below will be coordinated between the Board and the OPA.

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;
    b) Be provided to private low-income, multi-residential buildings throughout the 2015 to 2020 term;
    c) Require no 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.

6. Provide an education and training strategy;

   a) Encourage behaviour change of program participants toward a culture of conservation;
   b) Help low-income energy consumers help themselves;
   c) Help program participants to understand the benefits of participating in the low-income DSM program and conservation, in general; and
   d) 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 established by the OPA. Accordingly and as further described below, 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). 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) The 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.

## 2.7 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 education 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).

### 2.8 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 3.0 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 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. 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.

## 3. INPUT ASSUMPTIONS, SCREENING & AVOIDED COSTS

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 Review 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, the Board is proposing to lead the exercise to annually update the TRM throughout the duration of the new DSM Framework term (i.e., 2015 to 2020). The Board's proposed 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 TRM manual.

## 3.1 Input Assumptions

The 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 three general decision types: new, replacement, or retrofit.

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.

## 3.2 Screening Tests

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 2.8 and 2.3, 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 continue screening prospective DSM programs using the Total Resource Cost ("TRC") test. The TRC test measures the benefits and costs of DSM programs for as long as those benefits and costs persist. 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 test calculations are detailed in Section 3.2.3 below.

The natural gas utilities should also use the Program Administrator Cost ("PAC") test as a secondary reference 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 test but fail the PAC test and discuss the reasons the programs are still appropriate. PAC test calculations are detailed in Section 3.2.4 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 test, these programs should continue to be screened using a lower threshold value of 0.70.

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

### 3.2.1 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 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 "advanced" because of a natural gas utility's DSM programming efforts. Advanced 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. As further explained in section 4.7, a free rider is a "program participant who would have installed a measure on his or her own initiative even without the program."[1] 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.[2] 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 test.[3] However, as discussed below in section 3.2.2, 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.

### 3.2.2 Program Costs

For the purpose of the TRC 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.

[1] Violette, Daniel M. (1995) *Evaluation, Verification, and Performance Measurement of Energy Efficiency Programs*.
[2] Eto, J, (1998) *Guidelines for assessing the Value and Cost-effectiveness of Regional Market Transformation Initiatives*. Northeast Energy Efficiency Partnership, Inc.
[3] 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 benefit or cost from a societal perspective. As the TRC 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.[4]

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

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

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 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 analysis. Programs that have high free ridership rates will be less cost effective (as measured by the TRC 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.[5] If the spillover effects are considered and adequately supported (see section 4.7 for details), then programs that have high spillover rates will be more cost effective (as measured by the TRC 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.

[5] 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.

### 3.2.3 TRC Test Calculation

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

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

- Avoided Costs;
- Net Equipment and Program Costs; and
- Adjustments to account for free ridership, spillover effects, and persistence of savings and costs, as applicable.

The results of the TRC 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 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 ratio for a program falls below 1.0, the program would be screened out and no longer considered for inclusion as part of the DSM portfolio.[6]

To provide the Board with an appropriate amount of information regarding cost-effectiveness, all programs should be screened with the TRC test. The TRC 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 test, the utility should ensure its overall DSM portfolio has a TRC ratio of 1.0 or greater. Further, since low-income natural gas DSM programs may result in important benefits not captured by the TRC test, these programs should be screened using a lower threshold value of 0.70 instead.

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

The TRC ratio is expressed mathematically below:

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

Where:

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

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

And where,

| | | |
|---|---|---|
| $UAC_t$ | = | Utility avoided supply costs in year t (see section 3.3)<br>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 3.1 and 4.6. |
| $UAC_{at}$ | = | 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 3.2.2)<br>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 3.1 and 4.6. |
| $PCN_t$ | = | Net Participant Costs |
| $UIC_t$ | = | Utility increased supply costs in year t (see section 3.2)<br>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 3.1 and 4.6. |
| $N$ | = | 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 4.9) |
| $d$ | = | Discount rate (see section 3.4) |

### 3.2.4 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 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 3.3)
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 3.1 and 4.6

$UAC_{at}$ = Utility avoided supply costs for the alternate fuel in year t

$PRC_t$ = Program Administrator program costs in year t (see section 5.1.2)
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 3.1 and 4.6

| | | |
|---|---|---|
| $INC_t$ | = | 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 3.2.1) 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 3.1 and 4.6. |
| $N$ | = | 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 4.9) |
| $d$ | = | Discount rate (see section 3.4) |

## 3.3 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, operating and commodity costs[7].
- 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[8].

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.[9]

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).

[7] Commodity costs include those for natural gas and, if applicable, for other resources such as electricity, water, heating fuel oil and propane.
[8] 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.
[9] Commodity costs include those for natural gas and, if applicable, for other resources such as electricity, water, heating fuel oil and propane.

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.[10]

### 3.4 Discount Rate

For the purpose of cost-effectiveness tests (i.e., TRC, PAC, etc.), the total avoided costs resulting over the life of the DSM measures need to be discounted to a present value. The natural gas utilities should continue using a discount rate that is equal to their Board approved weighted average cost of capital ("WACC").

### 3.5 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 structured with a pay-for-performance cost recovery mechanism

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.

## 4. 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

[10] 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.

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, LRAM requests and shareholder incentive amounts claimed by the natural gas utilities.

## 4.1 Evaluation Process

For the duration of the term of the new DSM Framework (i.e., 2015 to 2020), and as discussed in the DSM Framework, the Board will take on the management function of the EM&V process, ensuring it to be an open process, where the Board will consult with both the gas utilities and stakeholders at appropriate junctures, seeking input on evaluation methodologies, key program features to ensure that the operational characteristics of the program generate the data and information that will provide the greatest assistance, and enable the evaluations to be robust and accurate. The Board will conduct annual evaluations and audits to verify that programs have resulted in the intended benefits, and to inform future program design and delivery.

In taking a more central role in the EM&V process, the Board will ensure that it is providing an appropriate level of oversight of the framework at the back end of the process as well as establishing expectations at the front end of the process.

The evaluation function of DSM programming and administration contains various steps throughout the process. The components of the evaluation process are outlined below along with the responsibilities of the respective parties:

- Evaluation Plan – role of the gas utilities and a required component of DSM Plan filings.
- Draft Evaluation Report – role of the gas utilities. This document will inform the larger review of program results managed by the Board.
- Independent Third Party Audit – role of the Board.
- Final Audit & Evaluation Report – role of the third party auditor. This report will provide final, audited and evaluation results related to the DSM programs delivered in the previous year.

### 4.1.1 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 which will be conducted by the Board, such as the data to evaluate 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 are 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 outline the following evaluation objectives:

- Helping identify key program evaluation metrics;
- Measuring natural gas savings and other resource savings, as applicable;
- Measuring the result for each of the metrics on the program scorecard(s);
- Measuring Net Equipment and Program Costs;
- Measuring cost-effectiveness;
- 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;
- Helping to 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; and,

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.

### 4.1.2 Draft Evaluation Report

The gas utilities will annually prepare a Draft Evaluation Report which should be filed with the Board on or 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 natural gas utilities should include, as an appendix to their Draft Evaluation Report, the verifications studies provided by their 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 LRAM 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 6.2 – Annual Draft Evaluation Report Template.

### 4.1.3 Independent Third Party Audit

Over the course of the new DSM Framework (2015-2020) 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[11]. This would enable the auditor to hire engineering firm(s) who will conduct the Custom Project Savings Verification ("CPSV") and the evaluation of other programs, as discussed further below.

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, LRAM and incentive amounts proposed by the natural gas utilities and any amendment thereto;
- 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 OPA's EM&V protocols, where applicable and relevant to the natural gas sector.[12]

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 program. 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 Evaluation Plan that has been approved by the Board.

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

#### 4.1.4 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 file with 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.

### 4.2 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 through 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.

#### 4.2.1 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."[13] In contrast, spillover effects refer to customers that adopt energy efficiency measures because they are influenced by a

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

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.

### 4.2.2 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-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 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.[14] The natural gas utilities also need 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.

In the absence of a partnership agreement on the sharing of the savings resulting from the program, the attribution should be based on the percentage of total dollars spent by the natural gas utilities.

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. For instance, a simple example is if a natural gas utility's allocated share is 30%, then 30% of the natural gas savings associated with the program will be counted towards the natural gas savings target.

### 4.2.3 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

[14] For example, if the partnership agreement allocates a share of 50% 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.

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.

# 5. 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 both the annual plans and long-term 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 5.6 below.

The natural gas utilities should apply annually for the disposition of any balances in their LRAMVA and DSMVA and, if applicable, apply for an 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.

## 5.1 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.

## 5.2 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 4.1.3).

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.

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.

## 5.3 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. 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 4.1.3).

## 5.4 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 4.1.3).

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.

### 5.5 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.

### 5.6 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.

## 6. 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. The natural gas utilities in all cases 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.

### 6.1 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 that both gas utilities' DSM Plans can 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) that DSM programs will be developed for and offered to.

2. Discussion and detailed plan for how the gas utility plans to meet its long-term natural gas savings target, 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 objectives 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) Projected annual incremental natural gas savings as well as other resource savings, if applicable;
    d) Goals, including program metrics and scorecards;
    e) Maximum shareholder financial incentive allocated to the program
    f) Length;
    g) 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 net savings and TRC 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) 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 4.1.1.

7. In addition to the information above, the following information should be provided for pilot programs (see section 2.4):

   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.

## 6.2 Annual Reporting – Draft 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 Draft Evaluation

Report template which will be used consistently by both gas utilities when preparing both the Draft Evaluation Reports. The Draft Evaluation Report template will be submitted to the Board by April 1st of each year as discussed in Section 4.1.2 above and then be used by the third party auditor when preparing its Audit & Evaluation Report. At a minimum, the Draft 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 $/6 years);
- historic annual actual DSM spending ($/year);
- DSM spending as a percent (%) of distribution revenue[15];
- historic annual shareholder incentives amounts available and earned ($/year);
- shareholder incentive earned as a percent (%) of DSM budget;
- annual and long-term natural gas savings targets ($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);
- historic total annual and cumulative gross and net natural gas savings ($m^3$) dating back to 2006;
- total annual and cumulative gross and net natural gas savings ($m^3$) from 2006 to the reporting year as a percent of total annual natural gas sales[16];
- actual annual gas operating revenue[17] ($/year);
- actual annual operating revenue less cost of natural gas commodity ($/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 4.1.2.

[15] 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.

[16] 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).

[17] Operating revenue figures should be taken from publicly available financial reports.