DEMAND SIDE MANAGEMENT GUIDELINES FOR NATURAL GAS UTILITIES

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1. OVERVIEW

Natural gas demand side management ("DSM") is the modification of consumer demand for natural gas through various methods such as financial incentives, education and other programs. While the focus of DSM is natural gas savings and the reduction in greenhouse gases emissions, it may also result in the saving of a number of other resources such as electricity, water, propane, and heating fuel oil.

1.1 Background

In 2006, the Ontario Energy Board (the "Board") conducted a generic proceeding (the "2006 Generic Proceeding") to address a number of issues related to natural gas utility DSM activities (EB-2006-0021). The Board's Decisions in this proceeding were issued in three phases:

- The Phase I Decision, issued on August 25, 2006, dealt with a large number of issues relating to DSM and set out a framework for a multi-year DSM plan;
- The Phase II Decision, dated October 18, 2006, approved the input assumptions for the DSM plans of Union Gas Limited ("Union") and Enbridge Gas Distribution Inc. ("Enbridge"); and
- The Phase III Decisions, released January 26, 2007 and April 30, 2007, approved Union and Enbridge's respective three-year DSM plans (i.e., for 2007, 2008 and 2009).[1]

The Board expected the framework established through the 2006 Generic Proceeding to result in significant regulatory savings for all parties involved.

In anticipation of the expiry of both Enbridge and Union's DSM plans at the end of 2009, the Board initiated a consultation process in October 2008 to review the DSM framework and establish through guidelines a revised DSM framework to be used by natural gas utilities in developing their next generation of DSM plans (EB-2008-0346). The first step in this consultation process was meetings led by Board staff with natural gas utilities and interested stakeholders representing ratepayer and environmental interests in November 2008.

On January 26, 2009, the Board issued its initial draft DSM guidelines for comment along with a Board staff discussion paper. On February 6, 2009, the Board also issued a draft report on "Measures and Assumptions for Demand Side Management (DSM) Planning" prepared by Navigant Consulting Inc. ("Navigant") for stakeholder comment.

On February 23, 2009, Bill 150, *An Act to enact the Green Energy Act, 2009, and to Build a Green Economy, to repeal the Energy Conservation Leadership Act, 2006 and the Energy Efficiency Act and to Amend Other Statutes*, ("the Green Energy Act") was introduced. On April 14, 2009, the Board issued a letter advising natural gas utilities

[1] Natural Resource Gas Limited ("NRG") has not filed any DSM plans with the Board.

that due to uncertainties relating to the Green Energy Act, it would not require the development of a new multi-year DSM framework for natural gas utilities. Instead, the Board required Enbridge and Union to file one year DSM plans for 2010 under the DSM Framework established through the 2006 Generic Proceeding. The Board's intention was that a one-year period would provide time for the impacts of the Green Energy Act to become clear. On April 29, 2009, the Board issued the final report prepared by Navigant Consulting Inc., which set out the input assumptions that natural gas utilities should use for the development of their 2010 DSM Plans.

On May 13, 2009, the Board issued a letter advising natural gas utilities that DSM programs targeted to low-income energy consumers would be considered separately from other DSM programs. More specifically, the Board indicated that the Low-Income Energy Assistance Program Conservation Working Group ("CWG") would establish the DSM framework for programs targeted to low-income consumers. Natural gas utilities would then have to submit their DSM programs for low-income consumers based on the resulting Board-approved low-income DSM framework. The CWG submitted its final report on a proposed short-term framework for natural gas low-income DSM on August 13, 2009.

By letter dated September 8, 2009, the Minister of Energy and Infrastructure[2] (the "Minister") advised the Board of the government's plan to develop a province-wide integrated program for low-income energy consumers, and requested that the Board not proceed to implement new support programs for low-income energy consumers in advance of a ministerial direction.

On September 28, 2009, the Board issued a letter along with the CWG report advising of the Board's new approach on this consultation in light of the Minister's letter. The letter also directed Enbridge and Union to submit their low-income plans for 2010 based on an extension of the DSM framework established under the 2006 Generic Proceeding.

By letter dated January 7, 2010, the Board directed Enbridge and Union to develop and file their DSM plans for 2011 based on the DSM framework established under the 2006 Generic Proceeding. In addition, the letter informed stakeholders that the Board would proceed with a review of the DSM framework and that it had retained the services of two consultants. Concentric Energy Advisors ("CEA") was retained to prepare a report that evaluates Ontario's DSM framework against best practices in selected North American and other jurisdictions. Pacific Economics Group Research ("PEG") was also retained to assess the potential use of normalized average usage per customer for estimating the impact of the DSM programs.

[2] The Ontario Ministry of Energy and Infrastructure was separated into two ministries on August 18, 2010: the Ministry of Energy and the Ministry of Infrastructure.

The CEA and PEG reports[3] were posted for written comment on March 19, 2010. A stakeholder meeting on the CEA report was held on April 29, 2010 and a webinar on the PEG report was held on May 13, 2010. On June 7, 2010, written comments from 17 stakeholder groups were received, with the vast majority of those comments directed at the CEA report.

On July 5, 2010, the Board received a letter from the Minister informing the Board that it should now resume its work in relation to low-income energy customers.

On January 21, 2011, the Board issued for comment a Staff Discussion Paper on Revised Draft Demand Side Management Guidelines for Natural Gas Utilities. Written comments from 15 stakeholder groups were received.

On March 29, 2011, the Board issued a letter informing participants of the Board's views and considerations regarding the role of ratepayer funded DSM activities. Written comments from 26 stakeholder groups were received.

1.2 Overview of the DSM Guidelines

The DSM Guidelines provide a framework for natural gas DSM programs that take into account the experience gained over the years, along with current circumstances, as informed by the extensive participants' comments received since the beginning of this consultation in October 2008, the Navigant report issued in February 2009, the August 2009 CWG Report, the CEA and PEG reports issued in March 2010, Board staff's proposed Revised Draft DSM Guidelines for Natural Gas Utilities issued January 2011, as well as stakeholders comments in response to the Board's March 2011 letter. In addition, an attempt has been made to maintain consistency, where appropriate, with the Ontario electricity Conservation and Demand Management ("CDM") framework.

The Board expects that distributors will comply with these filing guidelines at a minimum. Distributors are reminded that they should in all cases demonstrate to the satisfaction of the Board that any given application should be approved, and are responsible for ensuring to that end that all relevant information is before the Board (including evidence that may have been filed in an earlier proceeding). In addition, the Board may make any order or give any direction that the Board determines necessary concerning any matter raised in relation to any of the above applications, including in relation to the production of additional information which the Board on its own motion or at the request of a party considers appropriate.

DSM plans in Ontario have traditionally been filed by Enbridge and Union Gas. If NRG wishes to undertake distribution-rate funded DSM activities, NRG should consult with the intervenors in its most recent rate case to determine a DSM budget path proposal for Board approval.

[3] *Review of Demand Side Management (DSM) Framework for Natural Gas Distributors*, Concentric Energy Advisors, March 19, 2010 and *"Top Down" Estimation of DSM Program Impacts on Natural Gas Usage*, Pacific Economics Group Research, February 2010.

2. TERM OF THE PLAN

The initial term of the multi-year plans should be three years (2012, 2013 and 2014). The Board may consider a review of the natural gas DSM framework during the three-year plan term to determine whether to extend its term.

3. PROGRAM AND PORTFOLIO DESIGN

The design of natural gas DSM programs and the overall portfolio should be guided by the following three objectives:

- Maximization of cost effective natural gas savings;
- Prevention of lost opportunities[4]; and
- Pursuit of deep energy savings.[5]

The natural gas utilities may pursue DSM activities that support fuel-switching away from natural gas where these activities align with the above three DSM objectives and contribute to a net reduction in greenhouse gases.

In addition to the above three objectives, guidance on the design of the natural gas DSM programs and the overall portfolio is provided through the overarching DSM framework (e.g., screening, metrics, incentives, consultation process, etc.). This level of guidance is meant to ensure that adequate flexibility in DSM program and portfolio design is maintained, while recognizing that the natural gas utilities are ultimately responsible and accountable for their actions. This flexibility should ensure that the natural gas utilities can continuously react to and adapt to current and anticipated market developments.

To help ensure that an appropriate balance among the three overarching guiding objectives is maintained and that changes to the DSM plan are consistent with the other elements of the DSM framework, the natural 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, the natural 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 natural gas DSM program.

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[4] 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.
[5] Deep energy savings refer to measures that result in long-term savings, such as thermal envelope improvements (e.g., wall and attic insulation).

4. PROGRAM TYPES

As further described below, natural gas DSM programs should fall within the following three generic types: resource acquisition, market transformation and low-income programs. In addition, research and development and pilot programs should be reviewed on a case-by-case basis, with funding for these activities supported by the budgets associated with either or a combination of the three generics natural gas DSM program types.

4.1 Resource Acquisition Programs

Resource acquisition programs are programs that seek to achieve direct, measurable savings customer-by-customer and involve the installation of energy efficient equipment. For residential customers, these programs are primarily oriented toward rebates for installing energy efficient space or water heating equipment or building envelope upgrades. Programs designed for small businesses include incentives to invest in efficient devices such as low-flow pre-rinse valves for agricultural and grocery customers, air door heat containment systems, or kitchen ventilation systems for foodservice customers. For the most part, programs for new and existing commercial buildings are focused on the purchase and installation of efficient heating, ventilating, and air conditioning ("HVAC") systems. Because of the unique nature of industrial customers, solutions for those customers tend to be custom designed measures.

Custom projects are those projects that involve customized design and engineering, and where a natural gas utility facilitates the implementation of specialized equipment or technology not identified in the Board approved list of input assumptions. Projects that simply include a combination of several measures provided in the list of input assumptions are not considered to be custom projects.

4.2 Low-Income Programs

The purpose of DSM programs tailored to low-income consumers is to recognize that, although they 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.[6] 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 do not truly constitute a different type of generic natural gas DSM program, but are rather a set of resource acquisition and market transformation programs designed for and targeting 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.

[6] These various benefits not captured by the traditional net TRC savings measure may include reduction in arrears management costs, increased home comfort, improved safety and health of residents, avoided homelessness and dislocation, and reductions in school dropouts from low-income families.

Guiding Principles

The guiding principles for low-income natural gas DSM programs are that they should:

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

    a) Be accessible province-wide in the long term;
    b) Require no upfront cost to the low-income energy consumer and result in an improvement in energy efficiency within the consumer's residence; and
    c) Address non-financial barriers (e.g. communication, cultural and linguistic).

2. Be delivered in a cost-effective manner;

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) Use criteria for determining program eligibility.

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. Be a direct install program;

    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.

7. Provide on-going measurement of results, feedback and accountability for continuous improvement of the program and identification of best practices;

   a) Design programs that encourage persistence of energy savings.

8. Ensure that incentives for utilities are adequate for success; and

9. Have a DSM framework that strikes an appropriate balance between having a stable framework and having the flexibility to respond to changing market conditions.

   a) Be comprised of multi-year programs; and
   b) Allow for appropriate capacity building within the natural gas utilities and in the marketplace.

<u>Definition of Social & Assisted Housing</u>

For the purpose of low-income natural gas DSM programs, social and assisted housing means residential social housing including all non-profit housing developed, acquired or operated under a federal, provincial or municipally funded program including shelters and hostels.

Examples of residential social housing are:

- Non-profit corporations as outlined in the *Social Housing Reform Act, 2000*;
- Public housing corporations owned by municipalities directly or through Local Housing Corporations;
- Non-profit housing co-operatives as defined in the *Co-operative Corporations Act, 1990*;
- Non-profit housing corporations that manage/own rural and native residential housing;
- Non-profit housing corporations that manage/own residential buildings developed under the Affordable Housing Program; and
- Non-profit organizations or municipal/provincial governments that manage/own residential supportive housing, shelters and hostels.

<u>Low-Income Program Eligibility Criteria</u>

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.

4.3 Market Transformation Programs

Market transformation programs are focused on facilitating fundamental changes that lend to greater market shares of energy-efficient products and services, and on influencing consumer behaviour and attitudes that support reduction in natural gas consumption. They are designed to make a permanent change in the marketplace over a long period of time. These programs include a wide variety of different approaches. For example, such program approaches 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 incorporating drain heat water recovery systems in new buildings, the cost of which is much higher in existing buildings. Another example may be to improve 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 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).

4.4 Research and Development ("R&D") and Pilot Programs

R&D and pilot programs should be reviewed on a case-by-case basis, with funding for these activities supported by the budgets associated with one or more of the three generic types of natural gas DSM programs (i.e., resource acquisition, low-income, and market transformation programs).

R&D and pilot programs involve the installation, testing and/or evaluation of technologies that are not already in use in Ontario, or in limited use, and that serve as a tentative model for future development. R&D and pilot programs should strive to maximize the energy efficiency of technologies. A properly structured pilot should provide an opportunity to gain experience in business processes, installation procedures, logistics, deployment, integration issues, customer communications, and customer impacts.

Any application by the natural gas utilities to fund a DSM R&D or pilot program should include a rationale for how their program will increase the collective understanding of a technology and their benefits as a DSM measure. Where the R&D or pilot program involves a non-cost effective technology, the onus will be on the natural gas utilities to prove the usefulness of the program. The natural gas utilities should be prepared to share the results and knowledge gained through the R&D or pilot program with the Board and other utilities.

Where a technology is already being, or has been, installed, tested or evaluated by another utility, the natural gas utility that wishes to implement an R&D or pilot program using the same technology, will need to show how their program will result in additional benefits and how they will coordinate or work with the other utility to ensure effective use of the program and of the lessons learned.

R&D and pilot programs are critical to the success of DSM activities in the future, as they inform stakeholders to the appropriate development and delivery of future programs. These activities are not subject to scorecard evaluation nor are they eligible for a shareholder incentive.

5. Screening and Prioritization

The screening of DSM programs allows for the removal, from further consideration, of the DSM programs that do not meet the required threshold of the total resource cost test ("TRC"), as further explained below. To the extent that candidate programs that have passed the screening test cannot be undertaken due to budget constraints, prioritization among those programs must be performed to determine the final DSM program portfolio.

5.1 Screening Test

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. Some programs, such as market transformation, R&D and pilot programs are not typically amenable to a mechanistic screening approach and, as set out in sections 5.3 and 5.4, should be reviewed on a case-by-case basis instead. Among those 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 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 distribution costs (e.g., pipes, storage, etc.). The marginal costs also include the benefits of other resources saved such as electricity, water, propane and heating fuel oil, as applicable. Avoided costs are further described in section 6.2.

The costs considered in the TRC test are the Net Equipment and Program Costs associated with delivering the DSM program to the marketplace. Net Equipment and Program Costs are further explained in sections 5.1.1 and 5.1.2 below.

5.1.1 Net Equipment Costs

Net Equipment Costs relates 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 a societal perspective, 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 (a.k.a., 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 7.1, 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.
Net Equipment Costs associated with free riders are excluded from the TRC test.[8] However, as discussed in the section 5.1.2, 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.[9] However, as discussed in the section 5.1.2, 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

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

cost estimate. Net Equipment Cost estimates should be based on the best available information known to the natural gas utilities at the relevant time.

5.1.2 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.

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 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 <u>not</u> 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 from a societal perspective, 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 from a societal perspective.[10]

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 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.

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[10] 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.

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.[11] If the spillover effects are considered and adequately supported (see section 7.1 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 do generate benefits.

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

5.1.3 TRC Test Calculation

For screening purposes, the TRC test should be performed at the program level only.

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 from a societal perspective 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.[12]

The TRC threshold test should be 1.0 for all programs amenable to this screening test, except for low-income programs. To recognize that 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.[13]

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[11] 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.
[12] 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.
[13] These various benefits not captured by the traditional net TRC savings measure may include reduction in arrears management costs, increased home comfort, improved safety and health of residents, avoided homelessness and dislocation, and reductions in school dropouts from low-income families.

The TRC ratio is expressed mathematically below:

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

Where:

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

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

And where,

$Benefits_t = AC_t$

$Costs_t = NEC_t + PC_t$

And,

AC_t	=	Avoided costs in year t (see section 6.2) 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 6.1 and 7.
NEC_t	=	Net Equipment Cost in year t (see section 5.1.1) Net Equipment 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 5.1.1 and 7.
PC_t	=	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 5.1.2 and 7.
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 7.3)
D	=	Discount rate (see section 6.2.2)

5.2 Market Transformation Programs

Market transformation programs should be assessed on their own merits based on the specific objectives of the program.

5.3 Research & Development ("R&D") and Pilot Programs

R&D and pilot programs are not amenable to a mechanistic screening approach and should be assessed on their own merits based on the specific objectives of the program.

5.4 Prioritization

To the extent that not all candidate programs that have passed the screening test can be undertaken due to budget constraints, a flexible prioritization approach should be undertaken to take into account the iterative nature of DSM portfolio design. This flexible prioritization approach should also take into account:

- The three objectives outlined in section 3;
  - Maximization of cost effective cumulative natural gas savings;
  - Prevention of lost opportunities; and
  - Pursuit of deep cumulative energy savings.
- Inputs from the natural gas utility's DSM stakeholder engagement process;
- The overall natural gas DSM framework (e.g., metrics, targets, incentive structure, etc.); and
- Other inputs the natural gas utilities consider to be helpful (e.g., the PAC test, the TRC test (performed at the technology or measure level, at the program level, and at the portfolio level), etc.).

6. Development, Updating and Use of 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". Assumptions relating to society's 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) are referred to as "avoided costs".

6.1 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. 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 service areas.

6.1.1 Base Case Assumptions

Estimated savings and costs of DSM programs need to 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 should 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.

6.1.2 Updates to Input Assumptions During the DSM Plan

The input assumptions may change over time based on more accurate and up-to-date information, resulting from the annual evaluation and audit process and other research undertaken as required.

After the completion of the annual evaluation and audit process, and informed by the inputs obtained through their stakeholder engagement processes, the natural gas utilities should jointly consider whether any updates and/or additions to their set of approved input assumptions is required. In determining whether there is a need to update and/or add any input assumptions, the natural gas utilities may also take other research information into consideration.

The natural gas utilities should cooperate in preparing their individual applications for updates and/or additions to the set of approved input assumptions, and are encouraged to file a joint application. The application should be made as soon as practical after, but not prior to, the completion of the auditor’s final report (i.e., the Audit Report) on the natural gas utilities’ Draft Evaluation Report.[14] The application should be made annually, whether or not the natural gas utilities are requesting any changes to their set of input assumptions. The natural gas utilities’ annual application will provide a Board forum for stakeholders that will allow them to, among other things, request updates and/or additions to the set of input assumptions that may not have been identified by the natural gas utilities.

[14] The requirement set out in section 2.1.12 of the Board’s *Natural Gas Reporting & Record Keeping Requirements (RRR) Rule for Gas Utilities* indicates that “A utility shall provide in the form and manner required by the Board, annually, by the last day of the sixth month after the financial year end, an audited report of actual results compared to the Board approved demand side management plan with explanations of variances.” This requirement has effectively translated in a deadline to have the auditor’s final report on the gas utility’s evaluation report completed by June 30 of each year.

6.1.3 Use of Input Assumptions

The natural gas utilities should design and screen DSM programs using the best available information known to them at the relevant time. 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.

The evaluation of the achieved results for the purpose of determining the lost revenue adjustment mechanism ("LRAM") amounts and the 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 incentive amounts for the 2012 program year should be based on the updated input assumptions resulting from the evaluation and audit of the 2012 results. The updates to the input assumptions resulting from the evaluation and audit of the 2012 results would likely be completed in the second half of 2013.

Where feasible and economically practical, the preference to determine LRAM and 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.

6.2 Avoided Costs

As described earlier, assumptions relating to the societal 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) are referred to as "avoided costs".

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

- Avoided supply-side costs, such as capital, operating and commodity costs.
    - Commodity costs include those for natural gas and, if applicable, for other resources such as electricity, water, heating fuel oil and propane.
- 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.
    - 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.

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.[15]

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.[16]

6.2.1 Updating of Avoided Costs

The natural gas utilities should submit avoided costs for approval as part of their multi-year DSM plan, with the commodity costs to be updated annually (i.e., for natural gas and, if applicable, for other resources such as electricity, water, heating fuel oil and propane) but all other avoided costs (e.g., avoided distribution system costs such as pipes, storage, etc.) to remain fixed for the duration of the plan. As avoided costs should be based on long-term projections, it is expected that updating the remaining component of the avoided costs (i.e., other than the commodity costs) on a multi-year cycle should not cause benefits to be significantly under or overstated.

If an extension to the term of the plan is considered, as discussed in section 2, an updating of all the avoided costs should also be considered.

6.2.2 Discount Rate

For the purpose of the TRC test, 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")..

7. ADJUSTMENT FACTORS FOR SCREENING AND RESULT EVALUATION

The assumptions described in section 6 enable the calculation of savings accruing from specific measures or programs. Adjustment to those results must be considered to take into account the extent to which the natural gas utilities contributed to their achievement and the extent to which the savings are expected to persist. This exercise is done through the use of adjustment factors.

[15] Commodity costs include those for natural gas and, if applicable, for other resources such as electricity, water, heating fuel oil and propane.
[16] 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.

The four adjustment factors that are the topic of this section are free ridership, spillover effects, attribution and persistence.

As indicated in section 6.1.3, 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.

The evaluation of the achieved results for the purpose of determining the LRAM amounts and the incentive amounts should be based on the best available information which, in this case, refers to the updated adjustment factors resulting from the evaluation and audit process of the same program year. For example, the LRAM and incentive amounts for the 2012 program year should be based on the updated adjustment factors resulting from the evaluation and audit of the results of the 2012 program year.

7.1 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."[17] 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 each natural gas utility's ongoing program evaluation and audit process. 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, needs to be supported by comprehensive and convincing empirical evidence, which clearly quantify the spillover effects that of 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.

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

7.2 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 result from the activities of others.

Given the potential for greater coordination and even integration of certain 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.).

The natural gas utilities are encouraged to develop partnerships that result in economies of scale and economies of scope that benefit ratepayers.

7.2.1 Attribution 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.

7.2.2 Attribution 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.[18] The natural gas utilities also need to file expected spending for each of the partners before the program is launched and the actual amount spent by each partner within each program year. 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.

[18] 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.

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, 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.

7.3 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 time), 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.

More generally, an important consideration when assessing the persistence of savings is the fact that some energy efficient equipment have a much longer life than the base case equipment. For example, if an efficient natural gas furnace (model A) with a 25-year useful life is used to replace a homeowner's furnace (model B) with a remaining useful life of 5 years, an assumption must be made with regard to what would have happened under the base case. Would the average homeowner have opted to replace its furnace for a more efficient furnace (model C) on its own in five years from now? If so, estimated savings for the first five years should be based on the savings of model A compared to model B, but the savings over the next 20 years should be calculated by comparing model A to model C.

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. Given the natural gas utilities' 15 years of experience delivering natural gas DSM programs in Ontario, the natural gas utilities should undertake an assessment of the historical persistence of savings of custom DSM projects and commercial and industrial DSM programs in general and provide the resulting information to and consult with their stakeholders to determine whether any persistence adjustments to the savings of those programs would be warranted going forward.

There may be a trade-off between greater accuracy and the cost associated with developing persistence factors. For instance, it may be appropriate to carefully develop persistence factors for programs with significant budgets and savings, while other lower budget programs with measures that would not reasonably be uninstalled prior to the end of their useful life could be assumed to have a persistence factor of 100%. In either case, the natural gas utilities should provide a rationale for the persistence factor it is using for each of its programs. The natural gas utilities should seek guidance through its stakeholder engagement process to determine the extent to which persistence factors should be developed for each program.

8. BUDGETS

In a letter dated March 29, 2011, the Board stated the following:

> *The current DSM budget levels, which now represent about 2.8% and 4.1% of Enbridge's and Union's respective distribution revenues, have come to represent a sizeable portion of their business. The Board finds it appropriate at this time to limit the ratepayer funded portion of the natural gas DSM budgets to their current levels. Although the Board has been supportive of DSM activities within utilities over the years and remains supportive of DSM generally, it is concerned with the extent to which cross subsidies are appropriate within the Board's mandate of regulating gas distribution, and whether it is necessary for ratepayers to fund services which are available through a variety of channels in the marketplace.*

The 2011 DSM budgets for Enbridge and Union are $28.1 million and $27.4 million, respectively.[19] The Board has expressed the view that 2011 approved budgets should remain in effect for the 2012 to 2014 DSM plan term, subject to section 8.3. The budgets should be escalated annually using the previous year's Gross Domestic Product Implicit Price Index ("GDP-IPI") issued by Statistics Canada in the third quarter and published at the end of November.

The natural gas utilities should strive to remain on their DSM budget paths; any annual spending beyond that should be accommodated through the DSM variance account ("DSMVA") option. As further explained in section 13.2, the DSMVA "over-spend" option provides the natural gas utilities with the opportunity to spend and recover up to an additional 15% of their approved annual DSM budget, with all additional funding to

[19] See the Board's Decision and Order dated September 24, 2010 in Enbridge's 2011 DSM plan application – EB-2010-0175, and Decision and Order dated September 9, 2010 in Union's 2011 DSM plan application – EB-2010-0055. See also the Board's Decisions and Orders dated December 20, 2010 on Enbridge and Union's application to amend their respective low-income weatherization plan within their approved 2011 DSM plans (Board file number EB-2010-0175 and EB-2010-0055, respectively).

be utilized on incremental program expenses only. This option is meant to allow the natural gas utilities to aggressively pursue programs which prove to be very successful.

Budget flexibility will also be provided by the proposed funds re-allocation provisions described in section 3, regarding the re-allocation of funds for new DSM programs and re-allocation of funds amongst Board approved programs.

Actual DSM spending will be tracked in the DSMVA at the rate class level and will be used to "true-up" any variances between the spending estimate built into rates and the actual spending. The natural gas utilities should make an annual application for disposition of the balance in their DSMVA account, as further detailed in section 14.

The overall DSM budget flexibility will also be guided by expected funding levels for the three generic DSM program types as described below.

8.1 Budget for Resource Acquisition Programs

Resource acquisition programs should maintain the largest share of the natural gas DSM budget and its allocated budget should be sufficient to support the increased focus on deep measures. The natural gas utilities should consult with their stakeholders to determine appropriate budget levels for resource acquisition programs over the term of the plan.

8.2 Budget for Large Industrial Programs

The Board is of the view that large industrial customers possess the expertise to undertake energy efficiency programs on their own. As a result, ratepayer funded DSM programs for large industrial customers are no longer mandatory. If any are proposed, they will be considered on their merits. The Board defines large industrial gas customers as those in rate classes 100 and T1 for Union, and rate class 115 for Enbridge.

8.3 Budget for Low-Income Programs

The Board is of the view that the low-income DSM budget should be funded from all rate classes, to be consistent with the electricity conservation and demand management framework, as well as the LEAP Emergency Financial Assistance program.

The annual low-income DSM budget shall be no less than 15% of the natural gas utilities' total DSM budgets. Accordingly, the minimum low-income budgets for 2012 will be \$4.2 million[20] and \$4.1 million[21] for Enbridge and Union respectively.
The natural gas utilities' total DSM budgets may be increased by up to 10%, provided the funds are solely used to support low-income programs.[22] This means the total DSM

[20] Enbridge's total DSM budget \$28.1M*0.15 = \$4.2M
[21] Union's total DSM budget \$27.4M*0.15 = \$4.1M
[22] This is would represent an incremental amount to the natural gas utilities total DSM budgets of 1.5%

budget for Enbridge may be increased by $2.81 million and by $2.74 million for Union. This funding increase will be considered incremental to the natural gas utilities' total DSM budget and is not cumulative.

Appropriate flexibility and guidance for the allocation of the low-income DSM budget among low-income customers will be provided by the guiding principles outlined in section 4.2, inputs received through the natural gas utilities' stakeholder engagement process, as well as the Board's review and approval process of the natural gas utilities' multi-year plan applications.

The natural gas utilities should consult with their stakeholders to determine appropriate low-income DSM programs over the term of the plan. Those consultations should consider the degree to which coordination and/or integration of low-income natural gas DSM programs with low-income electricity CDM programs is warranted at this time, as well as consider the low-income DSM budget level required to support that recommendation.

The natural gas utilities should also file information providing a comprehensive overview of their low-income programs, which would include low-income programs within their residential rate classes as well as programs in other rate classes or sectors which are directed at low-income residents (e.g. social housing multi-unit residential spending).

8.4 Budget for Market Transformation Programs

Market transformation programs operate where competitive forces are not expected to yield the results wanted and might not achieve the results 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.

Taking the above considerations into account, the natural gas utilities should consult with their stakeholders to determine appropriate budget level for market transformation programs over the term of the plan.

8.5 Research and Development ("R&D") and Pilot Programs

The natural gas utilities should consult with their stakeholders to determine an appropriate budget level for R&D and pilot programs over the term of the plan.

8.6 Budget for Evaluation, Monitoring, and Verification

The level of effort required for Evaluation, Monitoring, and Verification ("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 expected that more extensive review will be undertaken for those programs that account for the majority of expenditures and savings. The natural gas utilities, informed through their stakeholder engagement processes, have the responsibility to propose appropriate EM&V requirements and the ensuing budget.

9. METRICS

Metrics refer to standard measurements used to assess the results of DSM programs. For example, cubic meters (m^3) of natural gas saved could be used as a metric to determine the impact of a DSM program.

9.1 Resource Acquisition Programs

To the extent possible, DSM metrics should be straightforward and verifiable. This objective must be balanced against the goal of providing signals consistent with the three guiding principles outlined earlier in section 3:

- Maximization of cost effective cumulative[23] natural gas savings;
- Prevention of lost opportunities; and
- Pursuit of deep cumulative energy savings.

It is recognized that there is a risk of using a single metric to drive multiple objectives. Accordingly, a scorecard approach, which takes into account multiple metrics, is recommended for resource acquisition programs. The scorecard(s) should include the following metrics:

- Cubic meters (m^3) of cumulative natural gas saved;
- $ spent per m^3 of cumulative natural gas saved; and
- Number of participants that receive at least one deep measure.[24]

The natural gas utilities, as informed through their stakeholder engagement processes, should define what constitutes a deep measure and propose the number, the organization of scorecards, the metrics used, and the weight associated with each metric. However, the inclusion of a TRC or societal net savings metric is not recommended; a metric based on m^3 of cumulative natural gas saved should be used instead. Likewise, the inclusion of a metric based on reduction of GHG emissions is not

[23] Natural gas savings over the life of an installed DSM measure.
[24] An agreed upon list of what constitutes "one deep measure" could include increase in insulation in more than half of the walls, basement walls, or the attic of the home.

recommended as this metric would strongly, if not perfectly, correlate with m^3 of cumulative savings of natural gas.

It is recognized that, under a budget constraint, rewarding the highest level of cumulative natural gas savings and going beyond a target deployment of deep measures will drive cost efficiency. However, it is expected that an explicit cost-efficiency measure, such as the "$ spent per m^3 of cumulative natural gas saved" metric, will provide greater transparency to all interested participants and the Board. It is also expected that setting explicit cost efficiency targets will allow the Board and interested participants, including the natural gas utilities, to better guide the development of the multi-year DSM plan and to optimize value for money from the first to the last DSM dollar spent.

9.2 Low-Income Programs

Low-income programs should be evaluated using a scorecard approach, which should help promote and strengthen the benefits of certain aspects of these programs. The low-income program scorecard(s) should include the following metrics:

- m^3 of cumulative savings of natural gas;
- $ spent per m^3 of cumulative natural gas saved; and
- Number of participants that receive at least one deep measure.[25]

The natural gas utilities, as informed through their stakeholder engagement processes, should propose the number, the organization of scorecards, the metrics used, and the weight associated with each metric, along with additional metrics.

9.3 Market Transformation Programs

Market transformation programs should be evaluated using a scorecard approach. To the extent possible and practical, a "m^3 savings of cumulative natural gas" metric should be included in market transformation program scorecard(s), along with a "$ spent per m^3 of cumulative natural gas saved" metric. Depending on the type of market transformation programs, other outcome based metrics should be proposed for inclusion on the scorecard(s) by the natural gas utilities, as informed through its stakeholder engagement process. As an example, metrics should include some quantitative and qualitative outcome-based results such as the extent to which lost opportunities are captured, increase in market penetration of specific measures, increase in education and awareness, and equitable access to programs to the extent reasonable.

[25] Ibid.

10. DSM TARGETS

A target refers to the level against which the actual result of a DSM program will be assessed. The target level can be set at the metric level (e.g., saving 100,000 m^3 of natural gas) and at the scorecard level (e.g., achieving a weighted score of the scorecard metrics of 100%).

Annual targets should be set for each of the program years. Recognizing, as outlined in section 5.1.3, that some multi-year programs may involve an initial ramp-up in the first year(s), the annual targets for those programs should reflect their initial ramp-up and consideration may be given as to whether the same or a different set of metrics and weights should be used during their initial ramp-up period. The natural gas utilities will develop and propose targets for each of the three years in their multi-year plan filing.

10.1 Resource Acquisition Programs

The targets for the metrics to be included on the resource acquisition program scorecard(s) should be developed by the natural gas utilities, as informed through their stakeholder engagement processes. Three levels of achievement should be provided on the scorecard(s) for each metric: one at each of 50%, 100% and 150%. The natural gas utilities should file evidence on the challenges they will face in meeting each of these three scorecard levels.

10.2 Low-Income Programs

Targets and metrics for low-income programs should be developed by the natural gas utilities, as informed through their stakeholder engagement processes, and should be submitted for approval by the Board as part of the multi-year plan application. Three levels of achievement should be provided on the scorecard(s) for each metric: one at each of 50%, 100% and 150%. The natural gas utilities should file evidence on the challenges they will face in meeting each of these three scorecard levels.

10.3 Market Transformation Programs

Targets and metrics for market transformation programs should be developed by the natural gas utilities, as informed through its stakeholder engagement process, and should be submitted for approval by the Board as part of the multi-year plan application. Three levels of achievement should be provided on the scorecard(s) for each metric: one at each of 50%, 100% and 150%. The natural gas utilities should file evidence on the challenges they will face in meeting each of these three scorecard levels.

11. INCENTIVE PAYMENTS

In accordance with the E.B.O. 169-III Report of the Board dated July 23, 1993, the natural gas utilities are provided with a return for the DSM activities they undertake consistent with the return available for other distribution activities.[26] In addition to this return, an incentive payment should be available to the natural gas utilities to encourage them to aggressively pursue DSM savings and recognize exemplary performance. DSM financial incentive amounts should not be included in the natural gas utilities' return on equity for the purposes of setting rates or in the calculation of any earnings sharing amounts.

The maximum incentive amount available for the 2012 program year should be $9.5 million for each of the two main natural gas utilities, to be escalated for inflation to determine the subsequent program year caps (the "Annual Cap"). The Annual Cap should be escalated using the GDP-IPI. The DSM incentive payments are pre-tax amounts.

To the extent that the *approved* DSM budgets deviate in magnitude from the Board proposed budgets, the Annual Cap should be scaled accordingly.[27] This will help ensure that the eligible incentive amount is consistent with the expected level of efforts require to achieve or exceed the approved targets. For greater clarity, and as implied by the proposed metrics outlined in section 9, the natural gas utilities will have an incentive to contain their *actual* costs while striving to achieve or exceed their targets; the proposed Annual Cap adjustment relates to the *approved* DSM budgets as opposed to actual expenditures.

The Annual Cap should be allocated among the three generic program types (i.e., resource acquisition, low-income, and market transformation programs) based on their approved DSM budget shares. For instance, if 10% of the *approved* annual DSM budget is allocated to one of the generic program types, then the maximum incentive available for results achieved under that generic program type will be 10% of the Annual Cap.

Likewise, incentive amounts paid to the natural gas utilities should be allocated to rate classes in proportion of the amount actually spent on each rate class. These incentive amounts should be tracked in a deferral account as further detailed in section 13.4.

As described in section 9, performance for all three generic types of programs (i.e., resource acquisition, low-income, and market transformation programs) will be evaluated using balanced scorecards. Also, as described in section 10, targets at 50%,

[26] The Board determined in its E.B.O. 169-III Report of the Board dated July 23, 1993 that "approved DSM costs should be treated consistently with prudent supply-side costs. Long-term DSM investments should be included in rate base and short-term expenditures expensed as part of the utility's cost of service."

[27] For instance, if the approved DSM budget is 25% less in a given year than the budget proposed by the Board, the maximum incentive amount for that year will be reduced by 25%.

100% and 150% will be established for each metric on the scorecards. No incentive will be provided for achieving a scorecard weighted score of less than 50%. For each metric on the scorecard, results will be linearly interpolated between 50% and 100%, and between 100% and 150%. Metric results below 50% will be interpolated using the 50% and 100% targets, metric results above 150% will be interpolated using the 100% and 150% targets.[28]

To encourage performance beyond the 100% target level, a pivot point should be introduced at the 100% level. More specifically, 40% of the incentive available should be provided for performance achieving a scorecard weighted score of 100% level, with the remaining 60% available for performance at the 150% level.[29] As indicated in section 10, the natural gas utilities should file evidence on the challenges they will face in meeting each of their three scorecard levels (i.e., 50%, 100% and 150%).

The incentive amount should be capped at the scorecard weighted score of 150%. The maximum incentive amount allocated to each generic type of DSM program should equal the sum of the maximum incentive amounts available for achieving weighted scores of 150% or above on all the scorecards.

12. LOST REVENUE ADJUSTMENT MECHANISM ("LRAM")

Utilities recover their allowed distribution revenues through both a fixed and a variable distribution rate. These rates are based on forecast consumption levels for their respective franchise area that take into account, among other things, the expected impact of naturally occurring energy conservation and the impact of planned DSM activities. If the actual impact of natural gas DSM activities undertaken by the natural gas utility in its franchise area results in greater (less) natural gas savings than what was incorporated into the forecast, the natural gas utility will earn less (more) distribution revenue than it otherwise would have, all other things being equal.

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[28] For example, if the 50%, 100% and 150% targets are 40 units, 60 units and 70 units respectively, then a result of 10 units would imply a metric score of -25%.

i.e., $50\% - \frac{(100\% - 50\%)}{(60 - 40)} * (40 - 10) = -25\%$

A result of 80 units would imply a metric score of 200%.

i.e., $150\% - \frac{(150\% - 100\%)}{(70 - 60)} * (70 - 80) = 200\%$

[29] For example, if the maximum incentive available is $1 million, the incentive payment will be $400,000 if the weighted scorecard result is 100%, and $1 million if the weighted scorecard result is 150% or above. As results are to be linearly interpolated, a weighted scorecard result of 75% would lead to an incentive payment of $200,000.

i.e., $\$400{,}000 * \frac{(75\% - 50\%)}{(100\% - 50\%)} = \$200{,}000$

A weighted scorecard result of 125% would lead to an incentive payment of $700,000.

i.e., $\$400{,}00 + \$600{,}000 * \frac{(125\% - 100\%)}{(150\% - 100\%)} = \$700{,}000$

The potential for deviations from the forecasted impact of planned DSM activities and the actual impact of DSM activities undertaken by the natural gas utility introduces a risk and a disincentive for the natural gas utility to deliver those DSM programs. The LRAM is designed to remove this disincentive by truing up the actual impact of DSM activities undertaken by the natural gas utility from the forecasted impact.[30] Accordingly, the LRAM amount is a retrospective adjustment and may be an amount refundable to or receivable from the utility's customers, depending respectively on whether the actual natural gas savings resulting from the natural gas utility's DSM activities are less than or greater than what was included in the forecast for rate-setting purposes. A natural gas utility may only claim 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 LRAM amount is determined by calculating the difference between actual and forecast natural gas savings by customer class and monetizing those natural gas savings using the natural gas utility's Board-approved variable distribution charge appropriate to the rate class. As described in section 6 and 7, the input assumptions, savings estimates, and adjustment factors used in the calculation of the LRAM amount should be based on the best available information resulting from the evaluation and audit process of the same program year. For example, the 2012 LRAM amount will be based on the best available information resulting from the evaluation and audit process of the 2012 program year.

The natural gas utilities should calculate the first 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 occurs in. This approach will help ensure that LRAM amounts closely reflect the actual timing of the implementation of the DSM measures.

It is expected that new load forecasts will incorporate the impact of natural gas DSM activities already undertaken. Accordingly, LRAM amounts are only accruable until distribution rates based on a new load forecast are set by the Board.

The recording of LRAM amounts, and the disposition of the balance in the LRAM variance account, is described in sections 13.3 and 14 respectively.

13. ACCOUNTING TREATMENT

The DSM plan components (e.g., budget, LRAM, incentive structure, DSMVA) will be established at the outset of a multi-year DSM plan with the intention of applying throughout the currency of the multi-year DSM plan. However, the DSM plan components will all be developed and measured on an annual basis within the multi-

[30] The LRAM serves to remove a disincentive for the gas utilities to undertake DSM programs. In contrast, the incentive payments as outlined in section 11. is meant to encourage the gas utilities to aggressively pursue DSM savings and recognize exemplary performance.

year DSM plan. 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 13.6 below.

13.1 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.

13.2 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. A natural gas utility may record in the DSMVA in any one year, a variance amount of no more than 15% above its DSM budget for that year. 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 14).

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, it is expected that the information available to the natural gas utility at the time the program was implemented will be considered.

13.3 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 rate class by 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 14).

13.4 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, which is expected to be 2012. 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 14).

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.

This account replaces the share savings mechanism variance account ("SSMVA"). The SSMVA will be discontinued once the balance associated with the 2011 program year has been disposed of.

13.5 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.

13.6 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.

14. Annual Application for Disposition of Balances in the LRAMVA, DSMIDA and DSMVA

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 Audit Report, the Stakeholder Report (if applicable), the Final Evaluation Report, and information setting out the allocation across rate classes of the balances in the LRAMVA, DSMVA and DSMIDA.

15. Program Evaluation

Effective monitoring and EM&V of DSM programs is a critical part of ensuring that programs are cost effective and generate the desired outcomes. Monitoring and EM&V also provides the natural gas utilities with the opportunity to identify ways in which a program can be changed or refined to improve its performance. Moreover, EM&V of

DSM activities is important to support the Board's review and approval of prudent DSM spending, LRAM and incentive amounts claimed by the natural gas utilities.

The California Evaluation Framework[31] identifies two key functions of evaluation:

1) To document and measure the effects of a program – "Summative Evaluations."

2) To help understand why those effects occurred and identify ways to improve the program – "Formative Evaluations."

Summative Evaluations, the first function, represents a threshold for assuring accountability for the expenditure of resources on that program. Summative Evaluation activities are done after the program has been operating and focus on documenting its impacts with a view to informing decisions regarding continuation, expansion or cancellation of the program.

The second function, called Formative Evaluations and often referred to as process evaluations, may be done earlier in a program's continuum and focus on providing feedback regarding the operational effectiveness of a program. The results of the evaluation serve to inform decisions regarding mechanisms to improve the program.

It is incumbent on the natural gas utilities to attempt to improve their programming capabilities over time. This may involve re-visiting the programs from time to time through the use of process evaluations (a.k.a., Formative Evaluations) that examine the effectiveness of the delivery. A certain level of process evaluation effort should be considered for all programs. Typically, process evaluations occur earlier in a program's life rather than later – i.e., early enough to revise the program as a result of the evaluation. This will vary based upon the size and nature of the programs, where they are in their life, and the similarity (or lack of similarity) to other delivery agents' programs. For small programs, the process evaluation effort could focus on secondary research augmented by interviews with key personnel involved in the program. Larger programs might involve greater depth of process evaluation including market research, surveys with participants and non-participants and related primary research activities. In the end, the intent is to ensure that programs operate at the highest level of effectiveness and that the process evaluation results are made available to other utilities to assist them in their delivery.

A key tenet of good program evaluation practices is the identification of the evaluation activities as part of the initial program design, which should be done by the natural gas utilities in consultation with their stakeholders through their stakeholder engagement processes. This ensures that the operational characteristics of the program generate the data and information that can assist in the program evaluation, such as the data to evaluate the scorecard metrics. It further ensures that the evaluation effort is 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-

[31] *The California Evaluation Framework*, TecMarket Works, June 2004, p. 28.

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.

15.1 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.

The Evaluation Plan should outline the natural gas utilities' proposed methodology to measure the programs' impacts (summative evaluation) and to assess why those impacts occurred and how the program can be improved (formative or process evaluation). More specifically, the Evaluation Plan should outline how the natural gas utilities will accomplish 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;
- Collecting other relevant information (for example and where applicable: technology type, number of installations, customer address or location, delivery channel, participant incentive amount, etc.);
- Informing decisions regarding LRAM and 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
- Other desired objectives, as determined by the natural gas utilities and as informed through its stakeholder engagement process.

It is the natural gas utilities' responsibility to ensure that those objectives are addressed for all of their DSM programs, including those delivered in partnership 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. The natural gas utilities, as informed through their stakeholder engagement process, are responsible for proposing the appropriate monitoring and EM&V requirements. The stakeholder engagement process should set out what the formal channel will be for the gas utilities' stakeholders, or a subcommittee thereof, to engage in the development of an evaluation plan and budget, and to review the evaluation results as they become available over the term of the plan.

For custom resource acquisition projects, which usually involve specialized equipment, savings estimates should be assessed on a case by case basis. It is expected that each custom project will incorporate a professional engineering assessment of the savings. This assessment would serve as the primary documentation for the savings claimed.

A special assessment program should be implemented for custom projects. The assessment should be conducted on a random sample consisting of 10% of the large custom projects; and the projects should represent at least 10% of the total volume savings of all custom projects. The minimum number of projects to be assessed should be 5. Where less than 5 custom projects have been undertaken, all projects should be assessed. The assessment should focus on verifying the equipment installation, and estimated savings and equipment costs.

All program result evaluations should be conducted by the natural gas utilities' third-party evaluator(s). If possible, the natural gas utilities' third-party evaluator(s) should be selected from the OPA's third-party vendor of record list. The natural gas utilities' third-party evaluators should seek to follow the OPA's evaluation, measurement and verification protocols, where applicable and relevant to the natural gas sector.[32]

15.2 Evaluation Report

The natural gas utilities should prepare a Draft Evaluation Report that provides a clear compilation of the results achieved during each program year (as evaluated by the natural gas utilities' third party evaluators) and it should accordingly be prepared on an annual basis. The Draft Evaluation Report informs stakeholders 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 evaluations conducted in support of those numbers. The Draft Evaluation Report is essentially a draft annual report of a DSM program year. As described in section 15.4, after a third party audit of the Draft Evaluation Report has been conducted, any required revisions are made to the report and a Final Evaluation Report is prepared. The process leading to the Final Evaluation Report (a.k.a. final annual report) is referred to as the evaluation and audit process.

As part of their Evaluation Report (i.e., draft and final), the natural gas utilities should provide an overview of the effectiveness of their DSM plan and an overview of each program, including the targeted customer class or group and the number of participants, the objectives of the program, duration of the program in years or months, and any activities associated with the program. The natural gas utilities should report on all initiatives worked on, and detail the process and impact analysis conducted for the individual programs.

[32] The OPA's evaluation, measurement and evaluation documents can be found on the OPA's website at: http://www.powerauthority.on.ca/benefits/evaluation-measurement-and-verification

The 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 Evaluation Report, the verifications studies provided by their third party evaluators, and any other relevant research and evaluation documents.

For R&D programs, pilot programs, custom projects, and other programs that do not have cost effectiveness data provided on the Board's approved input assumption list, the natural gas utilities should provide their own values, if available, and report all other relevant information.

If the input assumptions used by the natural gas utilities vary from those on the Board's approved list, the variation(s) should be identified, and additional information supporting the variation(s) should be filed. As outlined in section 6.1.3, the evaluation of the results achieved should be based on the best available information after the completion of the program year. It is expected that any variation from the Board's input assumptions list will be considered and sought based on the best available information after the completion of the program year and that such information will include the results from the third party evaluations.

If the specific technology promoted by the natural gas utilities is not included on the input assumptions list, the natural gas utilities may select a similar technology as a proxy. In this case, the natural gas utilities should identify the actual technology in their Evaluation Report and the similarities between the proxy technology and the actual technology. The natural gas utilities should also provide detailed evidence justifying the appropriateness of using the proxy technology, whether the associated input assumptions should be updated based on the best available information, and what steps they have taken, or will take, to determine the actual data for the technology used in the DSM program going forward.

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

The natural gas utilities should also indicate in their 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 natural gas utilities should indicate if a program is considered successful or not and whether the program should be continued. The Evaluation Report should outline the activities planned for the subsequent year(s) (if applicable) and any planned modifications to program design or delivery.

The 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.

15.3 Independent Third Party Audit

Informed by the advice from the stakeholder engagement process, the natural gas utilities should be responsible for selecting an independent third party auditor, determining the scope of the audit, and overseeing the audit of their Draft Evaluation Report. The third party auditor, although hired by the natural gas utilities, should be independent and ultimately serve to protect the interests of ratepayers.

At a minimum the independent third party auditor should be asked to:

- Provide an audit opinion on the DSMVA, LRAM and incentive amounts proposed by the natural gas utilities and any amendment thereto;
- Verify the financial results in the Draft Evaluation Report to the extent necessary to express an audit opinion;
- Review the reasonableness of any input assumptions material to the provision of that audit opinion; and
- Recommend any forward-looking evaluation work to be considered.

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 independent third party auditor's work will culminate in its final audit report (the "Audit Report").

The natural gas utilities should ensure that they fulfill their annual filing requirements under section 2.1.12 of the Natural Gas Reporting & Record Keeping Requirements Rule for Gas Utilities (the "RRR"), either by filing the Audit Report alone or along with additional documentation, as required.[33] Based on the natural gas utilities current financial year end, section 2.1.12 of the RRR requires those filings to be made by June 30 of each year for the immediately preceding financial year.

15.4 Finalization of the Evaluation Report

The natural gas utilities will provide responses to any recommendations and/or issues raised in the Audit Report and make any required revisions to its Draft Evaluation Report. The stakeholder engagement process should set out the process by which the

[33] Section 2.1.12 of the RRR states that "A utility shall provide in the form and manner required by the Board, annually, by the last day of the sixth month after the financial year end, an audited report of actual results compared to the Board approved demand side management plan with explanations of variances."

gas utilities' stakeholders, or a subcommittee thereof, will review the revised Evaluation Report and the natural gas utilities' responses to the Audit Report. The natural gas utilities will consider any additional inputs resulting from their stakeholder engagement process and prepare the Final Evaluation Report.

16. STAKEHOLDER INPUT AND CONSULTATION PROCESS

The natural gas utilities are ultimately responsible and accountable for their DSM activities and, accordingly, consultative activities should be undertaken at the discretion of the natural gas utilities. However, it is expected that this discretion will be guided by the overall DSM framework. Moreover, a recommended minimum stakeholder engagement is set out in the section 16.1.

The natural gas utilities may find, at their discretion, that broader stakeholder and expert engagement is appropriate. The natural gas utilities should determine, as part of their planning process, the appropriate amount to include in their overall DSM budget for stakeholder engagement, based on anticipated needs.

16.1 Stakeholder Engagement Process

All participants in the Board's consultation on the development of these Natural Gas DSM Guidelines (EB-2008-0346) should be invited to participate in the natural gas utilities' DSM stakeholder engagement process. As part of their stakeholder engagement process, each natural gas utility should hold a minimum of two meetings every year and invite all such participants (the "General DSM Meeting").

Among other things, the purpose of the General DSM meetings could include:

- Reviewing annual DSM results contained in the Draft Evaluation Report, the Audit Report and the Final Evaluation Report;

- Selecting any subcommittee that may be part of the stakeholder engagement process; and

- Providing advice on the development and operation of the natural gas utilities' DSM plan.

Terms of reference ("ToR") for the stakeholder engagement process should be developed by the natural gas utilities in cooperation with their stakeholders and submitted to the Board as part of the natural gas utilities' multi-year DSM plan application. The ToR should build upon experience to date and reflect, to the extent possible, consensus views of the natural gas utilities and their stakeholders. The ToR should set out any revision to the process for selecting the members of any subcommittee or confirm the continuation of the current approach.[34]

In drafting ToR for the stakeholder engagement process, the natural gas utilities and their stakeholders should consider including the continued advisory role of their stakeholders, or a subcommittee thereof, in relation to the following matters:

- Development of the DSM plan including allocation of DSM budget, target and metrics;
- Consultation prior to the filing of the DSM plan on evaluation priorities over the lifetime of the plan;
- Review and comment on evaluation study designs;
- Review of the scope and results of evaluation work completed on new programs introduced over the course of the DSM plan;
- Selection of an independent auditor to audit the Draft Evaluation Report and determine the scope of the audit. Stakeholders, or a subcommittee thereof, should ensure that all comments on the Draft Evaluation Report that arise from the General DSM Meetings are reviewed by the auditor;
- Following the audit, review the Evaluation Plan annually to confirm the scope and priority of identified evaluation projects; and
- Stakeholders, or a subcommittee thereof, should also be involved in the preparation of the natural gas utilities filing under section 2.1.12 of the Natural Gas Reporting & Record Keeping Requirements Rule for Gas Utilities. Stakeholders, or the subcommittee thereof, should provide a final report (the “Stakeholder Report”) within 10 weeks from the date of receipt of the Draft Evaluation Report and supporting evaluation studies from the utilities or the date of hiring of the auditor, whichever is later. Recommendations with respect to the disposition of any balances in the DSMVA, LRAMVA and DSMIDA should be included in the Stakeholder Report.

[34] Under the current approach, as set out in the 2006 Generic Proceeding, the Evaluation and Audit Committee (“EAC”) is a subcommittee constituted of four members of the gas utility’s group of interested stakeholders (the “Consultative”). One member of the EAC is a representative of the gas utility. The other three members are stakeholder representatives that are part of the Consultative and are selected using the following process. First, members of the Consultative nominate individuals to stand on the EAC. Then each member of the Consultative votes for the three members they would like on the EAC. The three members with the highest number of votes are selected to the EAC.

17. COORDINATION AND INTEGRATION OF NATURAL GAS AND ELECTRICITY CONSERVATION PROGRAMS

It is expected that greater coordination and integration of certain electricity and natural gas conservation programs could result in efficiency gains, thereby increasing total natural gas savings achievable at a given budget level. However, greater coordination or integration of natural gas DSM and electricity CDM programs should be encouraged, as opposed to being mandated. The natural gas DSM framework outlined in these Guidelines is expected to provide adequate flexibility and incentives to drive a rational coordination or integration of natural gas and electricity conservation programs. It is expected that the natural gas utilities will consult with stakeholders to design a proposed multi-year natural gas DSM plan that will reflect this objective.

17.1 Electricity CDM Activities Undertaken by a Natural Gas Utility

The natural gas utilities may undertake electricity CDM activities where they are clearly incidental to the natural gas utilities' DSM activities, provided they do not entail investment in separate infrastructure. It is expected that, where such engagement is undertaken, they should bring about cost efficiencies and the clear focus will remain the natural gas utilities' DSM activities. The natural gas utilities should use a fully allocated costing methodology for any electricity CDM activity they undertake.

The net revenues associated with any electricity CDM activity undertaken by the natural gas utilities should be shared equally between their shareholders and their ratepayers (50%/50%). No natural gas ratepayer funded financial incentive amount should be provided for electricity CDM activities undertaken by the natural gas utilities.

18. ADDITIONAL GUIDANCE ON MULTI-YEAR PLAN 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.

18.1 Filing of Multi-year DSM Plan

The natural gas utilities should file their latest market potential studies, and any updates thereof, along with their DSM plan. The natural gas utilities may, at their discretion, conduct additional market potential studies and/or update(s) during the term of their plan. The results of any such additional studies and/or update(s) should be shared with the natural gas utilities' stakeholders through their stakeholder engagement processes and be added as an appendix to their annual Evaluation Report.

The budget figures provided in the application should include all relevant DSM program costs including estimates for administration, evaluation, research (including any planned market potential studies and/or update(s) thereof), 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.

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

    a) Detailed description of the program;
    b) Customer class(es) targeted;
    c) Projected annual incremental natural gas savings as well as other resource savings, if applicable;
    d) Goals, including program metrics and scorecard;
    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 evaluation of the program.

3. 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.

4. 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 to the customer class(es) 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.

5. An Evaluation Plan, in accordance with section 15.1.

6. In addition to the information above, the following information should be provided for R&D and pilot programs (see section 4.4):

    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.

18.2 Mid-Term Updates

Mid-term updates refer to:

a) Requests for approval of new DSM programs; and/or
b) Budget reallocation among Board-approved DSM programs where the cumulative fund transfers exceed 30% of the approved annual budget for an individual natural gas DSM program.

A mid-term update application should include:

1. Current and proposed budgets for programs affected by the reallocation;
2. A description of the programs from which, and to which, funds are being reallocated;
3. The anticipated net benefits and goals of the reallocation;
4. Whether the natural gas utility is requesting that the Board proceed in accordance with section 21(4)(b) of the *Ontario Energy Board Act, 1998* under which the Board can dispose of the proceeding without a hearing; and
5. Where funding is being allocated to a program or programs that are not part of the natural gas utilities' Board approved DSM plan, the natural gas utilities should apply for approval of the proposed new program(s) at the time at which they apply for the proposed budget reallocation.

    a) The application for new DSM programs should, at a minimum, include a level of information consistent with the program-level information required in section 18.1.