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February 14, 2011

VIA RESS, EMAIL and COURIER

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, ON M4P 1E4

Re: Ontario Energy Board (the "Board")
File No.: EB-2008-0346
Demand Side Management ("DSM") Guidelines for Natural Gas Distributors

Some time ago, the Ontario Energy Board initiated a process to review the existing natural gas DSM framework and establish a revised framework to be used by the natural gas utilities in developing their next generation of DSM plans (EB-2008-0346).

As one step in that process, on January 21, 2011 the Board issued a staff discussion paper and revised draft DSM guidelines and invited parties to respond with written comments and recommendations by February 14, 2011.

Enbridge hereby submits the Company's response to the Board staff draft DSM Guidelines as circulated.

The Company notes that this response represents the continuation of extensive collaboration with Union Gas on issues relating to the DSM framework. The utilities worked jointly to develop their responses to the Concentric Report in the spring of 2010 and this response to the draft Guidelines is the result of further collaboration. On essential matters and issues of principle, the two natural gas utilities are in agreement on how the new framework for DSM should operate. Where there are differences in the submissions they arise from the application of commonly held principles to the unique circumstances of the two utilities.

Enbridge would welcome further dialogue with the Board staff on the draft Guidelines and encourages the staff to contact us directly if any recommendations or comments in this document are not clear.

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The submission has been filed through the Board's Regulatory Electronic Submission System ("RESS").

Please contact the undersigned if you have any questions.

Sincerely,

Norm Ryckman
Director Regulatory Affairs

Encl.

RESPONSE TO THE REPORT FROM THE ONTARIO ENERGY BOARD

Revised Draft Demand Side Management Guidelines for Natural Gas Utilities

(EB-2008-0346)

SUBMISSION FROM

ENBRIDGE GAS DISTRIBUTION INC.

February 14, 2011

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1.0 Introduction

This document presents the response of Enbridge Gas Distribution (Enbridge) to the Draft Demand Side Management Guidelines for Natural Gas Utilities (Draft Guidelines) as published by the Ontario Energy Board (the Board) on January 21, 2011.

The publication of the Draft Guidelines is one step in a process to establish a framework for DSM activities under the next DSM multi-year plan beginning in 2012. The process began in 2010 when the Board engaged Concentric Energy Advisors (Concentric) to "prepare a report that critically reviews, compares and assesses Ontario's DSM framework for natural gas distributors with respect to best practices in selected North American and other jurisdictions and to make recommendations on what changes, if any, should be made to the existing DSM framework for 2011 and beyond."

Following publication of the Concentric Report in March of 2010, the parties were invited to comment and Concentric later published responses to questions raised during the comment period. Enbridge and other parties submitted responses in June of 2010.

The framework governing DSM activities in the natural gas sector has been evolving since the gas utilities began to deliver DSM programs in 1995. The introduction of the shareholder incentive and audit in 1999 and the introduction of the first multi-year plan in 2007 are two major milestones. As the framework has evolved some guiding principles have remained constant, e.g., the commitment to offer programs to all ratepayer groups, while others such as the lost revenue adjustment mechanism (LRAM) have been introduced along the way.

This current round of discussions regarding the new framework for 2012 has been undertaken in recognition that the landscape for natural gas DSM in Ontario has changed significantly in recent years, that new approaches to program design and delivery are needed, and that a new framework is needed to facilitate the new approaches.

In its response to the Concentric Report, Enbridge articulated its view of the goals and guiding principles for this next generation of natural gas DSM in Ontario.

With an overarching goal of achieving deeper, lasting energy savings, the Company identified the need for initiatives that:

- "Avoid lost opportunities through a more integrated, comprehensive, and long term approach to meeting customers' energy needs, e.g., whole house retrofits;

- Recognize that, to the extent that a program will involve energy efficient technology, much potential for savings will be lost unless the behavioural patterns of the customer and their operational practices are addressed;

- Take a more customer centred approach and work intensively with customers to build a conservation culture within the organization, e.g., performance based efficiency (improvements), continuous commissioning, monitoring and targeting;

- Focus more on capacity building to develop the necessary soft infrastructure in the Province to further develop and support long term energy gains, e.g., training technicians in building simulation and/or training contractors in weatherization techniques;

- Move from examining isolated building efficiency opportunities to explore the next level of efficiency opportunities through integrated energy planning at the neighbourhood and community level, e.g., working with municipalities to explore opportunities through district energy systems that capture waste heat from one part of the community and transfer it to another sector; and

- Continue to aggressively support the development of new technologies and market approaches to energy efficiency through research and development."

As well, the Company identified the following guiding principles for the next generation of DSM:

- Transparent approaches and reporting mechanisms;

- Continuity and ease of access to programs;

- Stability of the framework and rules for program management and customer investment in energy efficiency;

- Equal access to programs for all ratepayer groups;

- Flexibility to allow program restructuring and optimization;

- An appropriate funding model to capture more savings;

- Fairness with respect to allocation of DSM resources and incentive structure; and

- Simplicity of administration and access.

In the Draft Guidelines, Board Staff also outlined key objectives and guiding principles for DSM in the coming period.

<u>Objectives</u>

- "Maximization of cost effective natural gas savings;

- Provision of equitable access to DSM programs among and across all rate classes to the extent reasonable, including access to low-income customers;

- Prevention of lost opportunities; and

- Pursuit of deep energy savings."

<u>Guiding Principles</u>

- Supporting an increases emphasis on deep measures;

- Ensuring equitable access to DSM programs among and across all rate classes

- Increasing coordination and integration of certain natural gas DSM programs with electricity CDM programs;

- Ensuring no undue rate impacts; and
- Ensuring no undue level of cross-subsidization within and across rate classes.

When examined together, these statements represent an emerging common understanding of the role that natural gas DSM should play in Ontario and how that role should be undertaken.

With regard to specific aspects of the framework to support the DSM goals, Enbridge is encouraged by many of the proposals in the Draft Guidelines:

- The introduction of scorecard metrics for all types of programs;
- The reintroduction of the Societal Cost Test (SCT) as a screening tool for introduction of resource acquisition programs;
- The expanded role for the Board and its consultant with respect to maintenance and updates to the list of approved input assumptions; and
- The call for new Terms of Reference for stakeholder engagement to reflect the circumstances of the new framework.

For some other aspects, it is Enbridge's view that the proposed mechanism in the Draft Guidelines either does not go far enough to provide meaningful support for the desired objectives or the proposed mechanism will work counter to the desired end. Key examples are:

- Limitations on the role of market transformation;
- Use of updated input assumptions;
- The suggested value for carbon emissions;
- The approach to free ridership and spillover; and
- The incentive structure.

These observations are based on the Company's extensive experience in delivering DSM programs and in managing DSM activities under various framework provisions over the past fifteen years. Where the Company differs from the proposed approach presented in the Draft Guidelines, Enbridge has presented an alternative approach that supports the Board's objectives and guiding principles.

The Company's detailed comments are presented in three sections:

Section 2: Background and Context, presents further detail on the developments leading to the Draft Guidelines.

Section 3: Guidelines Commentary, presents the Company's position and underlying rationale for those issues where the Company recommends a different approach to that offered in the Draft Guidelines.

Section 4: Proposed Revision to the Guidelines, presents proposed wording for the Guidelines. This section is provided in two formats: a black-lined version so that the suggested changes may be easily identified and a “clean” version for ease of reading. This section is presented for illustration. Section 3: Guidelines Commentary is to be taken as the definitive statement of the Company’s Response to the Draft Guidelines.

2.0 Background and Context

The OEB determined the original regulatory framework for natural gas utility sponsored DSM programs through guidelines established in its EBO 169-III Report of the Board dated July 23, 1993. That report presented a series of guiding principles that the natural gas utilities were expected to consider as part of the design and delivery of their respective DSM programs. These included the need for stakeholder engagement, the right of equal access for all potential customers, the use of existing delivery channels where appropriate, the desire to consider all energy conservation opportunities, the need for recovery of lost revenues, and the need to file evidence on the development, implementation, monitoring and evaluation of DSM programs, portfolios and plans.

These guidelines presented the natural gas industry with a framework under which DSM activities could be undertaken. This framework also provided certainty that those activities would not expose the shareholder to significant risk or unexpected negative outcomes.

Union and Enbridge responded by designing and launching a series of DSM programs and supporting initiatives starting in the mid to late 1990’s. Since that time, much has been accomplished and learned – both from the perspective of the marketplace, and from the perspective of the regulatory framework under which the programs are delivered. Shareholder incentives were added subject to a third party audit of annual results as one of several refinements to the DSM framework. Other principles were added including no retroactive changes to program assumptions and a more formalized role for intervenors through the Evaluation Audit Committee. In combination, these additions to the framework served to accelerate the DSM activities of the natural gas utilities resulting in significant gas savings for customers.

The individual and combined experience and knowledge of the natural gas utilities is a major resource available to the Province to assist in the selection of the best path for future DSM activity (including potential activities to be undertaken by electricity distribution utilities (“Electric LDCs”).

Since the last DSM framework was developed, several significant changes have occurred in the DSM landscape in Ontario which are shaping future DSM activities. These include:

- Greater government commitment to energy efficiency as exemplified by the Green Energy and Economy Act;

- Growing awareness of savings associated with natural gas as noted in a recent pronouncement from the Environmental Commissioner stating that “The potential savings on consumers bills and emissions reductions from reduced (natural gas) consumption is large – possibly more than savings from electricity;”[1]

[1] “Rethinking Energy Conservation in Ontario – Annual Energy Conservation Progress Report – 2009 (Volume One). Environmental Commissioner of Ontario. pp 31.

- Gains from first generation DSM programs are nearing maturity as exemplified by transformation of the market which has been achieved for some DSM technologies such as high efficiency furnaces, requiring new and greater efforts for further gains; and,

- Development of conservation programs in the electricity sector and further energy efficiency focused programming being driven by electricity reduction targets for Ontario's Electric LDCs.

As noted, the Board has also spelled out its main objectives for DSM activities by the natural gas utilities. These include:

- Maximization of cost effective natural gas savings;

- Provision of equitable access to DSM programs among and across all rate classes;

- Prevention of lost opportunities; and,

- Pursuit of deep energy savings.

The Board's objectives for DSM align with the province's view that more can be achieved through natural gas DSM. Enbridge welcomes the challenge. However, since many energy efficiency programming results have already been captured by our efforts, more DSM activity will require greater investments in portfolios combined with new ways of engaging the market. As well, it is clear that new initiatives focusing on capability building and collaboration with the electricity industry are required if we are to meet the Board's expectations regarding the maximization of savings.

Since the report from Concentric that described a potential new framework and our response to it, Enbridge has continued to effectively deliver its suite of DSM programs. The Company has also undertaken a further review of other jurisdictions' approaches and has reached out to its DSM customers to collect their feedback and insights to the current programming efforts and to new programs and opportunities that they believe are important. Finally, the Company has had extensive discussions with the electricity industry – both with the Ontario Power Authority (OPA) and with individual LDCs - regarding opportunities for collaboration in the delivery of energy efficiency focused programs. Opportunities for collaboration also exist in the natural gas sector and Ontario's gas utilities understand the practicalities of integrating efforts in DSM programming.

In combination, Enbridge's 15 years of experience, our review of the landscape of DSM activities, the feedback from customers and discussions around potential opportunities to collaborate have served to inform this response to the Draft Guidelines. The Company looks forward to assisting the Board as it contemplates the future of DSM in the province and believes that the Guidelines with the amendments as proposed by the gas utilities will enable the gas utilities to support the DSM objectives as outlined by the Board and to achieve a broad set of DSM activities that meet the utilities' customer needs and expectations.

3.0 Guidelines Commentary

This section is presented in the same order as the issues appear in Board Staff's Draft Guidelines document. For each issue, the Company has attempted to clearly state its position and offer rationale for that perspective. Note that for some issues where the Company accepts Board Staff's perspective and recommendation, no commentary is offered. In other instances where the Company accepts Board Staff's recommendation, comments are provided on Board Staff's supporting discussion.

Issue 2.0 Term of the Plan

Response

Enbridge accepts the three year planning horizon but submits that any potential extension to the term should only be considered following further consultation with the natural gas utilities which would provide the utilities with the opportunity to propose the appropriate levels for budgets, targets and incentives.

Comment

Enbridge contends that the nature of DSM programming and development process under which programs are rolled out does not support a simple extrapolation of an existing plan. Enbridge also submits that program penetration rates, particularly in the commercial and industrial sectors may extend beyond a 3-year time horizon and that the delivery and operation of programs must accommodate an easy transition into a post 3-year time frame. Market participants, especially those receiving incentives must have the assurance that incentive payments will be forthcoming even if the timeframe of the DSM plan has ended.

Issue 3.0 Program and Portfolio Design

Response

Enbridge does not support the Draft Guidelines proposed provision whereby utilities will be required to apply for Board approval in the event that cumulative fund transfers among Board-approved DSM programs exceed 30% of the approved annual DSM budget for an individual program.

Comment

The four key objectives for DSM activities set out in the Draft Guidelines align with Enbridge`s perspective on DSM activities as originally described in the Company's response to the Concentric Report.[2]

Enbridge contends that with respect to equitable access across rate classes, Enbridge anticipates delivering a portfolio of programs across all the major sectors of the market, including low income. These programs, including budgets, will be developed in consultation with stakeholders and customers and filed as part of the DSM planning exercise.

Regarding the re-allocation of budgets, Enbridge does not support Board Staff's position that the natural gas utilities be required to apply for Board approval 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. Enbridge's concern is that DSM programs operate in an often volatile market and that it is in the best interest of ratepayers that the

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Company have the flexibility to re-allocate budgets across programs, particularly in cases where programs may not be performing as anticipated. Conversely, when a program achieves unexpected rapid success in the market, the Company may need to re-allocate funds from other programs to finance the incentives and ensure no premature program interruptions in the market. At the same time the Company stresses the proven commitment of natural gas utilities to providing cost effective DSM programming to all of their customers. Enbridge refers the Board to the Company's record of consistently delivering programs to all customer rate classes for over 15 years. Recent years have seen the development of special programs targeted to low income households. The Company's record of commitment provides assurance that Enbridge will continue to provide quality programming to low income customers as the Company has done in the past.

Issue 4.1 Resource Acquisition Programs

Response

Enbridge recommends that commercial projects be included in the definition of custom projects.

Comment

Enbridge submits that larger commercial projects are also undertaken on a custom basis, similar to industrial projects and as such should be included in the definition.

Issue 4.3 Market Transformation Programs

Response

- Enbridge accepts the broad definition of market transformation as presented in the Draft Guidelines.
- The Company does not accept Board Staff's assertions that market transformation programs tend to be more applicable to lost opportunities, or that the Company's efforts be limited to specific niches within the broader market transformation arena.
- Enbridge recommends that the balance between market transformation programs and other program types should be determined in consultation with stakeholders during development of the DSM plan.

Comment

The broad definition of market transformation programs as articulated by the Board states, "Market transformation programs are focused on facilitating fundamental changes that lead 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…" Enbridge supports this definition of market transformation as it represents an industry accepted perspective and is consistent with the Company's interpretation of market transformation. Enbridge considers a variety of potential activities, including capability building initiatives such as training and education and segment support initiatives such as building benchmarking and support for related building industry events to be implicit in this wider definition.

Regarding Board Staff's assertions that market transformation programs tend to be more applicable to lost opportunities, or that the Company's efforts be limited to specific niches within the broader market transformation arena, Enbridge submits that market transformation is a strategic intervention in a marketplace intended to achieve a lasting, significant share of energy-efficient products, services and behaviours in the targeted markets – regardless of whether the targeted technology is a lost opportunity. That intervention can include a variety of activities as described above. Enbridge has and will receive guidance and insights from stakeholders and staff in considering potential DSM programming activities, including market transformation programs and these potential programming efforts should not be limited to either lost opportunity technologies or specific niche markets.

Enbridge recommends that the balance between market transformation programs and other program types should be determined in consultation with stakeholders during development of the DSM Plan. It is anticipated that through that consultation process, a significant share of the DSM budget and related level of effort will be directed to market transformation type initiatives.

Issue 4.4 RD&D and Pilot Programs

Response

- Enbridge recommends that the definition of this category of DSM activity be expanded as follows: RD&D and Pilot Programs are programs that involve the installation, testing, evaluation and piloting of emerging technologies, the piloting of innovative market approaches, capability building activities such as training, and pilot demonstrations of DSM concepts not already in wide use in Ontario.

- Enbridge recommends that a separate fund be established for each utility to support RD&D and Pilot Programs.

- Enbridge recommends that the Board encourage the natural gas utilities to use the fund to support co-operative activities with the OPA and electric LDCs.

- Enbridge recommends that RD&D and Pilot Programs will not be subject to scorecard targets or incentives.

Comment

Enbridge's view on this issue is definition provided by Board Staff is too narrowly focused on specific technology focused pilot projects. The Company believes that the definition should be expanded to include program development initiatives and pilot demonstrations of other innovative approaches, for example, community based program delivery, niche market program testing or financing of energy efficiency efforts on the property tax bill.[3]

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[3] In a series of DSM stakeholder sessions conducted by Enbridge in 2010, customers indicated that alternative program delivery methods and approaches should be considered a key part of the Company's market strategy.

Establishment of a separate development fund for each utility to support research, development and deployment activities focusing on emerging technologies and other pilot initiatives will ensure that sufficient resources are dedicated to ongoing development of future DSM activities. Keeping the DSM program development funnel full and developing capability is an essential activity to build towards the next multi-year DSM plan and facilitate continuous improvement in energy efficiency in the natural gas sector. Utilities would consult with stakeholders prior to accessing the fund to support individual initiatives. Activities undertaken from the fund would not be subject to scorecard evaluation or incentives.

Enbridge also notes that there is likely an opportunity to collaborate with the electricity industry through the use of a funding mechanism for pilot projects such as the Conservation Fund and Conservation Technology Fund currently operated and overseen by the OPA

Issue 5.1 Screening Test

Response

Enbridge agrees with assigning a value to CO_2 and recommends that a value of $60.00 per tonne or more be used.

Comment

Enbridge agrees with the general direction of assigning monetized values to specific externalities – in this case as expressed by a $/tonne of CO_2 value. Enbridge will accept a value determined by the Board as reasonable but notes that the $15 value currently proposed by Board Staff is both an under-quantification of the value of reducing CO_2 emissions and is not likely to be high enough to materially change the screening results for the majority of measures and programs that are currently in the Company's suite of programs or for potential new measures.

Enbridge also notes that, following EBO 169, a Board appointed Collaborative developed values for environmental externalities ranging between 0$ and $60. Following the guidance of the Collaborative, beginning with the first year of program delivery Enbridge and Union screened programs for inclusion in the DSM portfolio using the SCT test and a value of $40.00. This continued for several years until the SCT Test was replaced with the TRC test in 1999 with the introduction of the Shared Savings Mechanism. With this background, Enbridge encourages the Board to consider using a higher value for the CO_2 emissions amount to achieve its objective of encouraging technologies and programs that provide deeper savings. Considering that the Board, intervenors and the utilities accepted a value of $40.00 over ten years ago, Enbridge suggests that a value of $60.00 or more would be appropriate today.

Issue 5.1.1 Net Equipment Costs

Response

Enbridge recommends including a third type of equipment cost, i.e., the cost of equipment for advancement projects.

Comment

Enbridge contends that there is a third type of equipment cost which warrants consideration by the Board. This is the cost of equipment that is assigned to a project when a replacement decision is "advanced" because of the Company's DSM programming efforts. Advanced replacements or advancements (typically larger custom type projects) occur when an older, but still working lower efficiency technology is replaced with a more efficient piece of equipment. In these cases, Enbridge will adjust both the equipment life and the project cost to reflect the advancement.

There is a strong rationale for adjusting both the equipment life and the project cost to reflect advancements. In the Company's DSM experience, there are a significant number of older boilers that continue to operate, albeit at a lower efficiency, that are not likely to be replaced for some time. For these cases, the Company's overarching aim is to move the customer to a higher level of efficiency and have a corresponding project cost that reflects the nature of the transaction.

Issue 5.1.2 Program Costs

Response

With regards to program costs included in the TRC test, Enbridge differs with Board Staff regarding which costs should be allocated to individual programs. The Company recommends that the following costs be allocated to individual programs:

- Start-up costs;
- Promotion;
- Delivery; and
- Verification and some Evaluation costs.

The Company further recommends that the following costs be allocated at the portfolio level:

- Development costs;
- Some Evaluation costs;
- Monitoring and Tracking; and
- Administration.

Comment

Start-up costs can be assigned to individual programs, however development costs are more appropriately assigned across the entire portfolio as not all program concepts will make it through the program development funnel to implementation. For some resource acquisition programs, verification costs may also be attached to an individual program. Similarly, some market transformation programs may require program specific market research to assess the opportunity or the results. Otherwise, development, evaluation, monitoring, and administration costs should be considered across all program types, consistent with the current practice. This approach acknowledges the portfolio level costs associated with operating a DSM enterprise.

Issue 5.1.3 Modified TRC Test Formula

Response

- Enbridge supports the approach whereby multi-year programs which may not result in net benefits in their first year may be screened on a multi-year basis.

- Enbridge recommends that the Draft Guidelines be amended to clearly state that this approach supports on-going investments in new programming activities and therefore will be applied to programs which are introduced in the last year of the multi-year plan as well as to programs which are introduced in the first or second year.

Comment

Enbridge supports the Board Staff's perspective on the screening of multi-year programs and the potential change in the TRC result versus a single year program However, Enbridge submits that the proposed approach implies that DSM activity will end at the end of the plan period. This is not the case, instead, Enbridge will continue to develop new programs throughout the period and some of those may not show results until the next plan period. There needs to be provision for ongoing program development and deployment, particularly as relates to programs that might be deployed in year two or year three of the plan or even beyond the plan period. It is expected that the utilities will continue to offer DSM programs beyond 2014 and that some of those programs will have been initiated in the current programming timeframe. This is entirely consistent with the current practice.

Issue 6 Development, Use and Updating of Assumptions

Response

- Enbridge supports the process to establish and maintain a common set of measure assumptions at the beginning of the multi-year plan period and maintain these assumptions through an annual process review using an independent consultant and a Board proceeding.

- Enbridge encourages the Board to undertake activities in support of this process at the earliest possible convenience and to retain the consultant for the full term of the multi-year plan.

6.1.2 Updates to Input Assumptions During the DSM Plan

Response

- Enbridge supports the proposed role of the Board in updating measure assumptions.

- Enbridge requests the support of the Board for Enbridge and Union to begin work on development of a model for a province wide DSM Technical Council.

Comment

As stated in the Draft Guidelines, each year, following the evaluation audit process, the utilities will submit an application to the Board. The Board's consultant will provide a technical review of any applications for new or updated program assumptions. The Board will initiate a proceeding that will provide a forum for stakeholders to comment on the application and / or to request updates and/or additions to the set of input assumptions that may not have been identified by the utility. Following the proceeding, the Board will issue a Decision regarding any new or updated input assumptions. Enbridge notes that updating input assumptions using the current process has proven to be time-consuming, cumbersome and an inefficient use of evaluation expenditures. The Board's proposed role will clarify and streamline the process for adding and updating measure assumptions during the plan period.

As a next step, Enbridge requests Board support for Enbridge and Union to begin work in 2011 to develop a model for a DSM Technical Council and to present a proposal to the Board as soon as possible. The Technical Council or similar entity would be a multi-party body created to establish and maintain input assumptions and manage the Evaluation, Measurement and Verification processes for both electricity and natural gas DSM activities.

6.1.3 Use of Input Assumptions

Response

- Enbridge recommends that, for the purposes of the incentive calculation, updated measure assumptions become effective the beginning of the month following the Board Decision confirming the assumptions.
- Further, that for the purposes of LRAM calculation, input assumptions be adjusted retroactively to reflect the best available information at the time of the audit.

Comment

Enbridge has serious concern with the application of "retro-active" revisions to input assumptions and notes that this issue was previously resolved with unanimous support from the intervenors and was approved by the Board in the Generic Proceeding (EB-2006-0021) ("Generic Proceeding") for the purposes of the SSM calculation. Enbridge submits that this is a fair and appropriate methodology as the SSM assessment is intended to be a measure of how the utility performed against its target. Any consideration of retroactive application of revisions to input assumptions undermines the need for certainty in elements of the regulatory oversight required to ensure a climate that encourages aggressive and leading edge program development

Under Board Staff's proposed process for updating of input assumptions, any proposed changes to input assumptions arising from the audit will be submitted through an application to the Board following the audit process. Enbridge proposes that, once the Board has issued a Decision regarding any new or updated input assumptions, the new values become effective from the beginning of the month following the Board's Decision. Enbridge notes that in some cases, a change in input assumptions may cause a DSM program that is being implemented to now fail the SCT test. If this should occur, the utility should not be obliged to cancel the program immediately but must be allowed to make a measured withdrawal of the program from the market.

For the purposes of the LRAM calculation, Enbridge supports the position that the input assumptions be adjusted to reflect the best available information at the time of the audit as this adjustment is only for the purposes of providing an accurate true-up of incremental volumes in the preceding program year and not for the purposes of determining the utility's incentive.

Issue 6.2.3 Discount Rate

Response

- Enbridge supports the establishment of a common discount rate for natural gas DSM activities and that the rate to be set for the term of the multi-year plan.
- Enbridge recommends that the Board adopt the OPA discount rate for application to the SCT screening of DSM programs for the natural gas utilities and publish the rate in the Final Guidelines document.

Comment

Enbridge agrees that a single discount rate should be selected and applied for all SCT cost effectiveness analysis for both natural gas utilities and that the Board will determine the discount rate following stakeholder comments. Enbridge recommends that the OPA discount rate be applied as that will further facilitate collaboration between natural gas and electricity DSM/CDM programs in the province.

Issue 7.0 Free Ridership and Spillover Effects

Response

Enbridge recommends that, for purposes of calculating DSM savings, free ridership and spillover be considered to cancel out.

Comment

Enbridge contends that free ridership and spillover have equal and opposite impacts effectively cancelling each other. This view is consistent with the view expressed in the Concentric Report.

Regarding the use of free ridership rates that differentiate by both market segment and technology, Enbridge submits that this approach is costly given its relatively limited value added within the overall environment that the programs operate.[4] This view was also articulated by Concentric which stated that the accurate measurement of free ridership and spillover are particularly troublesome and may not be worth the effort given a need to focus on market transformation of DSM technologies.[5] Free ridership studies have many limitations including:

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[4] Note that the cost of the free ridership studies undertaken by the two natural gas utilities in 2007 and 2008 was over $400,000 covering free ridership studies undertaken for custom projects, and a selection of prescriptive technologies.

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[5] IBID. pp 68.

cost, the qualitative nature of the work, the applicability across sub-sectors or regions, customer survey fatigue and others. Given these limitations, in the event that a nominal value is not applied, Enbridge proposes to undertake studies of this nature only in a limited number of cases.

In the event that the Board decides that free ridership should be applied prescriptively, Enbridge submits that a single and uniform value be applied to all DSM activities for both natural gas utilities. Enbridge recommends that an amount of 10% be applied, consistent with the views expressed in the Concentric Report.

Issue 7.2.1 Attribution Between Rate-regulated Natural Gas Utilities and Rate-regulated Electricity Distributors

Response

- Enbridge supports the approach suggested by Board Staff.
- Enbridge recommends that the SCT benefits from electricity savings be included in the screening results for the natural gas utilities.

Comment

Enbridge generally supports the approach suggested by Board Staff but requests that the Board clarify its position on the use of electricity savings in the screening of programs offered by the natural gas utilities where those programs deliver electricity savings. Enbridge notes that customers don't make decisions regarding gas and electricity in isolation and therefore recommends that the savings from electricity and resulting SCT benefits should be included in the screening results for the natural gas utilities.

Issue 7.2.2 Attribution Between Rate-Regulated Natural Gas Utilities and Other Parties

Response

- Enbridge recommends the use of the term "arrangement" rather than "partnership" to reflect cases where other non-regulated entities are engaged in co-delivery of programs.
- Enbridge recommends that where the other party is a municipality, another level of government, or a public agency, the approach recommended by Board Staff at Issue 7.2.1 be applied, i.e., 100% of the gas savings are attributed to the natural gas utilities and 100% of the other savings, e.g., water savings are attributed to the other party.
- Enbridge recommends that for other arrangements, Board Staff's approach should apply but that the threshold should be set at greater than 40% of the share that would have been allocated based on a percentage of total dollars spent.
- Enbridge recommends that the utilities not be required to file expected spending by the partners before the program is launched.

Comment

Enbridge believes that the term “arrangement” more accurately reflects the range of potential co-delivery options.

For circumstances where the other party is a municipality, other level of government or public agency, Enbridge contends that this is a parallel situation to that with the electric LDCs and should be treated in the same manner, i.e., the gas utilities may claim 100% of the gas savings and the other parties claim the other savings.

Regarding the requirement to provide an explanation if the share of savings in the agreement is greater by 20% than the share which would have been allocated based on a “percentage of total dollars spent” basis Enbridge proposes that the threshold for providing supporting evidence re: savings allocation be 40%. This threshold will serve to better encourage the utility to seek out collaborative arrangements and funding partners for its programs - arrangements which serve to improve the overall cost effectiveness of DSM spending.

With respect to the filing requirements, Enbridge notes that collaborative arrangements may arise after program launch and that prior approval of the Board is impractical in these cases. Further, to maximize collaboration the gas utilities need flexibility to take advantage of opportunities as they arise.

7.3 Persistence

Response

Enbridge recommends that, beyond studies to assess removal rates, further persistence studies are not warranted at this time.

Comment

Enbridge appreciates Board Staff’s perspective on the persistence issue as there are cases where early removal of energy efficient equipment may occur. Enbridge does undertake persistence studies where the issue of product removal is deemed to be particularly relevant. Enbridge contends that this approach is adequate to address programs where product removal may occur, and it is not necessary therefore to consider persistence studies for other programs because the overarching equipment life assumption is an accurate assessment of persistence. Enbridge submits that undertaking potentially costly persistence studies on all the programs in the portfolio is not a cost effective allocation of the utility’s limited evaluation budget.

Issue 8 Budgets

Response

Enbridge accepts the general direction that Board Staff have provided regarding the need for an increased budget.

Comment

The Company understands the need for a budget increase to address the greater expectations inherent in the Board’s proposed direction. At the same time Enbridge notes that it is important to maintain a balance between promoting increased energy efficiency and concerns for potential rate impacts associated with increased DSM budgets. Enbridge prefers to develop the budget in light of the goals, the anticipated level of effort for the various programs, and our assessment of what is required to meet those goals. This “bottom-up” approach to budget setting represents standard practice in DSM planning and one which the Company has used in previous DSM plans.

Issue 8.1 Budget for Resource Acquisition Programs

Response

Enbridge proposes that the budget allocation across program types be developed in consultation with stakeholders during development of the plan.

Comment

Enbridge contends that the budget allocation should necessarily be established by the level of effort identified through the DSM planning exercise, which is guided by the key objectives and over-arching strategy. Enbridge submits that the balance between the various program types should be determined in consultation with stakeholders during development of the DSM Plan. Enbridge expects that resource acquisition programs will continue to be a critical element of its DSM portfolio, however until the DSM plan is established, the size and nature of the allocation of the budget across program types should not be pre-determined.

Issue 9 Metrics

Response

Enbridge generally supports the scorecard approach, but is not in favour of a blanket approach to determine the metrics used.

Comment

The Draft Guidelines acknowledge the need to have a flexible framework. Enbridge contends that the establishment of the metrics must also reflect that need. In practice, negotiating multiple scorecards will be a time-consuming activity. For some program types, it will be more effective to have a single scorecard where the metrics are the same. Enbridge proposes to use one scorecard for resource acquisition programs and one scorecard for low income programs. Market transformation programs, by their nature, will require individual scorecards. In the absence of individual program metrics, Enbridge can provide intervenors with information on sector plans and budgets to demonstrate that they have fulfilled the mandate to provide programs to all sectors and customer classes. Enbridge further notes that the metrics identified by Board Staff may be contradictory. In particular, the $\$/m^3$ metric appears to countervail the deep savings metric since deep savings are typically the result of greater per unit investments in incentives and programming costs.

Issue 11.0 Incentive Payments

Response

Enbridge recommends an incentive structure that:

- Starts at the first unit achieved;
- Has no cap;
- Increases by 15% year over year to reflect increase in level of effort; and
- Provides an incentive at 100% achievement that is proportionate to the 100% incentive under the negotiated settlement in the 2006 Generic Proceeding.

Comment

Board Staff has proposed that the budget for the DSM programs of the natural gas utilities should be increased significantly over the three years of the multi-year plan. In the case of Enbridge, Board Staff proposes an increase of 30% per year, such that in the year 2014, its budget will be $62 million. This represents an increase, relative to Enbridge's budget in 2011, of more than 120%.

At the same time, Board Staff are proposing, in effect, a reduction in the quantum of the incentive available for the natural gas utilities who successfully undertake and deliver their DSM plans. This represents a significant departure from the reasoning and purpose for an incentive mechanism.

The long-standing accepted purpose of an incentive mechanism is that it is necessary to attract the attention of management and to support the promotion and aggressive pursuit of delivering benefits to ratepayers. In the end, the prime directive of DSM activities is to generate bill savings for ratepayers. Historically, ratepayers have benefitted from the DSM activities of the natural gas utilities to a value which is now into the billions of dollars. That is, their natural gas, electricity, water, propane and fuel oil savings, in the aggregate, are estimated to be in the range of $2 – 3 million when the activities of both natural gas utilities are combined.

Enbridge believes that as its budget is increased during the three years of the multi-year plan, ultimately to a level of $62 million, it will generate significantly more natural gas savings for its ratepayers. This will, of course, require significantly more effort by Enbridge's management and DSM staff, and will imply significantly greater responsibility and program delivery risk.

Historically, the natural gas utilities have shared in the energy bill savings generated by the utility, to a reasonable level. Thus the name "Shared Savings Mechanism" and its acronym "SSM". With the proposed significant increase in DSM budgets and the associated opportunity for the natural gas utilities to generate significantly greater savings for ratepayers in future, it stands to reason that the natural gas utilities should share to a reasonable extent in these savings given their additional effort. Indeed, it is to be expected that ratepayers would promote an incentive level which does precisely that – encourages the utility to maximize savings benefits for ratepayers.

There can be no question that the effort required of Enbridge will be significantly greater to plan, roll out and deliver successful DSM programs over the coming years. With the budgetary increases as proposed, there will be more programs, more planning, more result evaluations, and more oversight required than ever before – this in an environment where cost effective gas savings opportunities are more difficult to identify and achieve.

There also can be no question that Enbridge's O&M costs to deliver DSM programs will increase significantly over the next 3 years. Over the past 10 years, Enbridge's DSM O&M costs have constituted between 16% and 24% of total DSM spending in each year. It is foreseeable that this range of spending to operate DSM programs will continue in the future. Such increases would be consistent with the observation that along with bigger budgets and expectations comes greater effort.

Enbridge notes that Board Staff's proposal that the incentive payable at 100% of target be equal to 40% of the cap in effect lowers the incentive that a natural gas utility can earn relative to the current incentive at the 100% level, which is $5.25 million. It should be recalled that this figure was the subject of a negotiated settlement in 2006, which was reviewed and approved by the Board.[6] Board Staff have recommended, at page 34 of the Draft Guidelines, a proposal that the natural gas utilities would earn only 40% of the maximum incentive available of $9.5 million when they achieve 100% of the target. Expressed numerically: 40% of $9.5 million is $3.8 million - a decline of almost 28% from the current incentive of $5.25 million at the 100% level.

Board Staff do not provide any rationale for this decrease in their submissions, despite the fact that such a recommendation appears inconsistent with the proposed requirement that the 100% target level be "appropriately challenging"[7] and that each of the natural gas utilities "should file evidence on the challenges they will face in meeting each [their] scorecard levels."[8]

With the level of management attention and effort by DSM Staff that will be necessary to support the increase in budgets, Enbridge strongly believes that the incentive payable at the 100% target level should not go down but rather increase to a reasonable level to reflect the additional efforts required to generate additional energy bill savings for ratepayers. It is entirely reasonable under the circumstances that the incentive should increase proportionately to the budget, or in proportion to the additional energy bill savings generated by the natural gas utilities. If natural gas savings generated by DSM programs double over the next three years, a valid case can be made for a doubling of the incentive payable at the 100% target.

While a reasonable argument in favour of such an increase can be made based upon the savings enjoyed by ratepayers, Enbridge understands the sensitivity associated with seeking approval of such an increase on top of the proposed budgetary increases. For this reason, it proposes a modest compromise.

Enbridge recommends that rather than linking the increase in any incentive directly to the increase in the DSM budget or natural gas savings, the incentive increase by a nominal factor of 15% to reflect the increased level of effort attendant with the significant budget increases over the term of the plan.

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[6] The incentive is calculated in two parts: 100% of the resource acquisition target generates an incentive of $4.75 million. Achieving target for market transformation issues generates an additional incentive of up to$500,000 (Issue 5.2 and 10.4 from the Generic Proceeding, EB-2006-0021)

[7] Board Staff Submission, January 21, 2001, p. 63

[8] Revised Draft DSM Guidelines, January 21, 2001, p. 32

	Incentive @ 100% ($million)		
	Current Incentive	Board Staff Proposal	Enbridge Proposal escalated by 15%
2011 (Generic Decision)	$5.25 (plus $400K low income = $5.65)	$3.8	$5.65
2012	$5.65	$3.8 +CPI	$6.50
2013	$5.65	$3.8 +CPI (2 years)	$7.47
2014	$5.65	$3.8 +CPI (3 years)	$8.59

	Incentive @ 150% ($million)		
	Current Incentive	Board Staff Proposal	Enbridge Proposal escalated by 15%
2011 (Generic Decision)	$10.34 (incl. low income)	$9.5	$10.34
2012	$10.34 + CPI	$9.5 +CPI	$9.75
2013	$10.34 +CPI (2 years)	$9.5 + CPI (2 years)	$11.21
2014	$10.34 + CPI (3 years)	$9.5 + CPI (3 years)	$12.89

If a natural gas utility does not increase its budget to the maximum permitted under the Draft Guidelines as proposed by Board Staff, then the increase to the incentive level at 100% would be increased only in proportion to the increase in budget. For example, if Enbridge's budget is increased by only 15% (half of what Board Staff proposes), the incentive would increase by only half, or 7.5%.

It is submitted that the use of the 15% nominal value still understates the increase in effort that will be required of Enbridge to efficiently roll out and operate programs during the multi-year plan. It is to be expected that the level of Enbridge's actual efforts and its O&M costs will increase by more than 15% per year. It should also be acknowledged that the current incentive payable at the 100% target of $5.25 million has not changed since 2006. It has not even kept pace with inflation. This alone warrants an increase in the incentive at the 100% level. Add to this the certainty that the natural gas utilities will be put to significantly greater effort and risk achieving future DSM targets given the complexity of many programs and the increasing number of DSM-type programs being offered and undertaken by entities across the province and the challenges which the natural gas utilities face become all the more apparent.

These realities and the need to maintain the attention of management and provide an incentive to the natural gas utilities to maximize results to the benefit of ratepayers support such a change.

Under the current DSM framework and as agreed to by all stakeholders during the Generic Proceeding, the incentive payable to the natural gas utilities was based upon a non-linear curve with the incentive amount payable increasing at several pivot points along that curve. The logic behind this proposal was that the natural gas utility would be rewarded at greater levels when it achieved higher results and it would be rewarded at lower amounts for only modest success.

With the move to scorecard results which allows for flexibility in the development of the metrics used for various program types and/or specific programs, it is important to recognize that the overlay of the current non-linear curve (related to TRC benefits generated) with scorecards (related to numerous metrics and variable success levels) does not function appropriately. Indeed, overlaying a non-linear curve over a scorecard, which itself may contain a type of non-linear approach to measuring success, could operate in an unwanted and inappropriate fashion. The unintended consequence of applying different non-linear equations to one another is that it may tend to amplify the results in directions which would at times penalize a natural gas utility from continuing to deliver DSM programs and fail to measure the true success of the programs. In other words, it could overly exaggerate the impact of a pivot point beyond the intention and purpose of the pivot point in the first instance.

Accordingly, in situations where DSM results will be determined by the use of multiple scorecards, Enbridge submits that it becomes extremely important to make use of a linear straight line basis to calculate the incentive payable, beginning with the first m^3 of gas savings realized. It is important to recognize that the metrics used on various scorecards may require a certain threshold level of success to be met in respect of a specific measured value before natural gas savings at certain levels are generated. The targets on the scorecards are therefore the key to the measurement of success for the program or program types in question. The straight line incentive structure therefore simply becomes the means to calculate the incentive payable, not the means to measure the success of programs or program types. That is the role of the scorecards.

This straight line basis for calculating incentives continues to award the natural gas utilities on the basis of results. If the results are marginal, as determined by the multiple scorecards, then the incentive realized will be marginal. If the natural gas utilities achieve the 100% target levels, then it is appropriate for them to be rewarded at that level and for the incentive to continue on the same basis for exceptional success beyond the 100% level.

Finally, it should be noted that, even with the proposed increase in incentive, the ratio of the incentive (at 100%) relative to the total budget will decrease over the period of the plan from 18.75% in 2011 to 12.8% in 2014.

Issue 13.2 DSMVA

Response

- Enbridge supports the continuance of the DSMVA as a mechanism which enables the utilities to carry on successful programs.

- Enbridge recommends that access to the DSMVA be administered on a program type basis.

Comment

Under the current framework, the DSMVA is applied on a portfolio basis; the utilities may access the DSMVA provided that they reach the portfolio target. The Company recognizes that this may not be practical under the new framework which encompasses three program types. Enbridge proposes that the utility be permitted to recover from ratepayers up to 15% above its annual DSM budget for a program type provided that:

- It has achieved its scorecard targets for the program type; and
- The funds are used to produce results in excess of the targets.

Enbridge does not agree with administering access to the DSMVA on an individual program basis. This will add unnecessarily to the administrative burden and reduces the utility's ability to drive results such as deep savings or lost opportunities.

13.3 LRAM Variance Account ("LRAMVA")

See Issue 12.

15.1 Evaluation Plan

Response

Enbridge agrees to file an Evaluation Plan as part of its multi-year DSM plan submission; this is consistent with the practice for the submission of the current multi-year plan.

Comment

With regard to the requirements of the evaluation plan, it should be noted that DSM program results are not "measured" but rather calculated as is the case in respect of natural gas savings. Metrics on program scorecards are tracked or calculated as in the case of cost-effectiveness. Regarding the special assessment program for custom projects (the annual engineering review), a detailed sampling methodology was developed early in the current multi-year plan by a third party consultant and in consultation with the Evaluation Audit Committee. Enbridge proposes to continue using the current sampling methodology.

15.2 Evaluation Report

Response

Enbridge supports the proposed approach.

Comment

Board Staff's proposal for the Evaluation Report reflects the current process which Enbridge follows with respect to the DSM Annual Report.

15.3 Independent Third Party Audit

Response

Enbridge is supportive of the continuation of the third party audit until such time as another Board approved process assumes the functions currently handled by the third party auditor.

Comment

Enbridge notes that Board Staff's proposal to update input assumptions has streamlined the audit process and the process for approval of assumption updates. The function of the EAC and the auditor with respect to the review of evaluation work on input assumptions will now be carried out by the Board's consultant as part of the annual application process for assumption updates and approval of new measure assumptions.

As stated in Section 6.1.2 Enbridge supports a process to develop a model for a DSM Technical Council. In addition to establishing and maintaining the input assumptions and EM&V processes, the Terms of Reference for such a Council could also include management of the DSM audit process for the natural gas utilities. Alternatively, the model could include management of the DSM audit process by the Board. Enbridge looks to the Board for support in the development of a model for future presentation to the Board and stakeholders.

16 Stakeholder Engagement Process

Response

- Enbridge acknowledges that the utilities are ultimately responsible and accountable for their DSM activities.

- Enbridge recommends that the Terms of Reference for the stakeholder engagement be revised in recognition of the expanded role of the Board and the changing role of the auditor with respect to DSM input assumptions.

Comment

The Company acknowledges the statement in the Draft Guidelines that, "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."

Enbridge and ratepayers have benefited greatly from stakeholder engagement in its DSM activities and the Company has carried out extensive stakeholder consultation during the term of the current multi-year plan. These activities include Consultative meetings, meetings of the Evaluation Audit Committee, stakeholder consultation in development of the Market Transformation program metrics for 2010 and 2011, consultation on the 2011 Low Income plan and the 2011 DSM plan and also consultation to support development of the 2012 plan.

Enbridge notes that the practice of stakeholder consultation is constantly evolving. As presented in the Draft DSM Guidelines, stakeholders are involved in the natural gas utilities' DSM activities both through Board processes and through the utility's DSM stakeholder engagement process. Board processes include participation in Board proceedings relating to:

- application for approval of the DSM multi-year plan;
- annual application for approval of updates to assumptions or assumptions for new measures;
- annual application for clearance of DSM variance accounts; and,
- any applications for mid-term updates to the plan.

Under the Draft Guidelines, the Board will manage an annual process for the update of measure assumptions and review of assumptions for new measures. Evaluations completed with respect to program assumptions will be reviewed by the Board and its consultant during that process and stakeholders may be engaged in the review of such evaluations at that time.

The utilities' stakeholder engagement process includes participation in:

- development of the DSM plan; and,
- the annual DSM audit.

In recognition of the expanded role of the Board with respect to DSM input assumptions and the resulting changes to the role of the auditor, Enbridge recommends that the Terms of Reference for the utilities' stakeholder engagement be revised to include the following:

- participation in development of the DSM plan, including budget, target and metrics;
- selection of the independent auditor and determination of the scope of the audit;
- ensure that all comments on the Draft Evaluation Report (the Annual 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 utility's 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 utility 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.

Finally, Enbridge notes that the stakeholder engagement outline provided above represents the approach as developed within the Board's proposed processes for assumption updates and the DSM audit. The development of a model for a DSM Technical Council would have to include consideration of the role for stakeholder involvement in such a model.

17.1 Electricity CDM Activities Undertaken by a Natural Gas Utility

Response

Enbridge recommends that the Guidelines include a note to the effect that, with respect to the Enbridge IR model, net revenues arising from CDM activities are unrelated to any incentive regulation earnings sharing ("ERM").

Comment

The treatment of revenue to gas utilities from electricity CDM activities will be unique to the utility's operations.

18.2 Mid-Term Updates

Response

- Enbridge agrees with the Board Staff's recommendation regarding mid-term updates.
- Enbridge recommends that the Draft Guideline be expanded to include other circumstances in addition to requests for approval of new DSM programs or budget reallocation.

Comment

For example, a sudden and significant year-over-year change in avoided gas costs could cause the utility to seek a change in screening protocols, scorecard metrics or targets for particular programs. Similarly, the unexpected removal of electricity CDM from the market could undermine a number of programs and cause a need to re-focus efforts elsewhere. Such changes may merit a mid-term update and the Draft Guideline should be sufficiently flexible to permit this to occur.

Conclusion

The Introduction and Background section of this document referred to the many changes in the DSM landscape. Looking forward to the 2012 multi-year DSM plan, Enbridge fully supports its participation in DSM activities for several reasons. DSM aligns with the Company's Green Energy Strategy. Established rules encourage management to treat DSM as an important part of the Company's ongoing business. As well, DSM furthers provincial goals relating to energy efficiency and Enbridge's participation supports the Company's social responsibility.

All parties recognize that, given the many recent changes to the DSM landscape, a new DSM framework is needed. In developing the new DSM Guidelines, Enbridge encourages the Board to ensure continuity, fairness and stability by integrating new features such as the scorecard approach with established principles such as the treatment of assumption updates.

The Company recognizes that several of the framework features proposed by the Board are designed to accelerate and expand DSM activities into new areas. While the Company recognizes the need for oversight and proper administration of DSM activities, the Board has pointed out that the utilities are ultimately responsible for DSM activities. With recognition of the utilities' responsibility for DSM, Enbridge suggests that it will be important for the Guidelines to include provision for flexible programming and to avoid restricting the ability of the utilities to effectively manage their DSM activities.

Where changes to the Draft Guidelines are proposed by Enbridge, they are made with the goal of streamlining current practices even further and/or to make the future framework complementary with the realities of the market today.

To further support this Response and the Board's development of new DSM Guidelines, the Company has provided Section 4 of this document. Section 4 presents the Draft Guidelines as amended with Enbridge's suggested revisions and additions.

4.0 Proposed Revision to the Guidelines

Attached are clean and blacklined versions of the Draft Guidelines with proposed changes reflective of the submissions made by Enbridge in this response.

APPENDIX A:

Revised Draft Demand Side Management Guidelines for Natural Gas Utilities

EB-2008-0346

Date: February 14, 2011

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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 that due to uncertainties relating to the Green Energy Act, it would not require the

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

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.

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

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[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.

[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.

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.

1.2 Overview of the Revised Draft DSM Guidelines

The Revised Draft DSM Guidelines outline a proposed framework for natural gas DSM programs that is not fundamentally different from the natural gas DSM framework that resulted from the 2006 Generic Proceeding. The Revised Draft DSM Guidelines do however propose changes in many areas of the framework to account for the experience gained over the years and the 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, as well as the CEA and PEG reports issued in March 2010. In addition, an attempt has been made to maintain consistency, where appropriate, with the Ontario electricity Conservation and Demand Management ("CDM") framework. In particular, an attempt has been made to take into account the results of the Ontario Power Authority's ("OPA") consultations on the 2011-2014 province-wide electricity CDM programs as well as the recent Board consultations on electricity CDM.[4]

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 and, following consultation with the natural gas utilities about appropriate budgets, targets and incentives, if the Board is satisfied that the natural gas DSM framework remains appropriate, the Board could extend its term, subject to appropriate program-specific exceptions for programs that require multi-year terms beyond the extension.

3. PROGRAM AND PORTFOLIO DESIGN

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

- Maximization of cost effective natural gas savings;
- Provision of equitable access to DSM programs among and across all rate class sectors (i.e., residential (including Low Income), commercial and Industrial) to the extent reasonable, including access to low-income customers;

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[4] Ontario Energy Board consultations on a Conservation and Demand Management Code for Electricity Distributors (EB-2010-0215) and on Electricity Conservation and Demand Management Targets (EB-2010-0216).

- Prevention of lost opportunities[5]; and
- Pursuit of deep energy savings.[6]

The natural gas utilities may pursue DSM activities that support fuel-switching away from natural gas where these activities align with the above four DSM objectives and contribute to a net reduction in greenhouse gases. Fuel-switching to natural gas is not a DSM activity and DSM funds should not be used for this purpose.

In addition to the above four 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 adequate flexibility in DSM program and portfolio design is maintained, 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 four overarching guiding objectives is maintained and that proposed changes to the DSM plan is consistent with the other elements of the DSM framework, the natural gas utilities are required to seek approval to re-allocate funds to new programs that are not part of the natural gas utility's Board-approved DSM plan.

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, development and deployment and pilot programs should be reviewed on a case-by-case basis, with funding for these activities supported by a designated budget.

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 and

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

some larger commercial customers, solutions for those customers tend to be custom designed measures.

Custom projects are those projects that involve customized design and engineering, and where the 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.[7] 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 programs, 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.

<u>Guiding Principles</u>

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;
    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;

[7] 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.

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;

   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;

   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;

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;

   b) Allow for appropriate capacity building within the natural gas utilities and in the marketplace.

Definition of Social & Assisted Housing

For the purpose of the 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.

Low-Income Program Eligibility Criteria

To facilitate coordination between low-income electricity CDM and natural gas DSM programs, eligibility criteria for low-income consumer consistent with those established by the OPA's should be followed. 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 will be the responsibility of the natural gas utility, through their agent responsible for low-income program eligibility screening, to confirm participant eligibility.

1. Income Eligibility Criterion

The low-income natural gas DSM program income eligibility criterion requires meeting at least one of the following four criteria:

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;

b) Primary or secondary name on utility bill is a recipient of one of the following social benefits:

i) The National Child Benefit Supplement;

ii) Allowance for the Survivor;

iii) Guaranteed Income Supplement;

iv) Allowance for Seniors;

v) Ontario Works; or

vi) Ontario Disability Support Program.

c) All social and assisted housing units are eligible for low-income natural gas DSM programs. 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 its 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 assisted housing. All residents of social and 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 assisted housing will be the first point of contact for social and 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);

ii) If a social and assisted housing resident identifies themselves to the program, the natural gas utility (or its delegates) will either direct the resident to contact their housing provider, or the natural gas utility (or its 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. 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) or output-based (e.g., delivering a given number of workshops).

4.4 Research Development and Deployment (“RD&D”) and Pilot Programs

RD&D and pilot programs should be reviewed on a case-by-case basis, with funding for these activities supported by a dedicated budget, the amount to be determined through development of the multi-year plan. RD&D and pilot programs are not subject to scorecard targets or incentives.

A pilot program is one that involves the installation, testing and/or evaluation of technologies, methodologies or arrangements (hereinafter jointly “Process”) that are not already in use in Ontario, or in limited use, and that serves as a tentative model for future development. 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 a natural gas utility to fund a DSM R&D or pilot program should include a rationale for how its program will increase the collective understanding of a Process and its benefits as a DSM measure. Where the R&D or pilot program involves a non-cost effective Process, the onus will be on the natural gas utility 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 Process is already being, or has been, installed, tested, used or evaluated by another utility, a natural gas utility that wishes to implement an R&D or pilot program using the same Process will need to show how its program will result in additional benefits and how it 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 as to the appropriate development and delivery of future programs. Such activities would not be subject to scorecard evaluation nor 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 modified total resource cost test ("modified TRC"), as further explained below. To the extent that not all candidate programs that have passed the screening test can be undertaken due to budget constraints, prioritization among those programs must then 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. All other natural gas DSM programs should be screened using the total resource cost ("TRC") test, as modified to include a value for the reduction in greenhouse gases ("GHG") emissions as measured in tonnes (1,000 kg) of carbon dioxide equivalent emissions ("CO2e"). 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 modified TRC test.

The modified TRC test measures the benefits and costs of DSM programs from a societal perspective 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, and the reduction in CO2e emissions. Avoided costs are further described in section 6.2.

The costs considered in the modified 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 modified 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 the natural gas utility's DSM programming efforts. Advanced replacements (typically larger custom type projects) 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 utility 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."[8] 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 modified TRC test.[9] However, as discussed in the section 5.1.2, all Program Costs associated with free riders should be included in the modified TRC analysis.

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

Spillover effects are essentially the mirror image of free ridership. Net Equipment Costs associated with spillover effects are included in the modified TRC test.[10] 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 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 modified 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 modified 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.

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[10] Ibid.

i) 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 the 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.[11]

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) Evaluation, Verification 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. Evaluation costs relating to a specific program are allocated to the program.

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 clarity, it is not practical to allocate administrative costs to individual programs. These costs will continue to be accounted at the portfolio level.

Program Costs should be considered as part of the modified TRC test for as long as they persist (e.g., verification costs may be spread over a period of time). Free ridership

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

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 modified TRC analysis. Programs that have high free ridership rates will be less cost effective (as measured by the modified TRC test) since their Program Costs will be included in the analysis while their benefits will not.

The spillover effects are associated with customers that adopt energy efficiency measures because they are influenced by a utility's program-related information and marketing efforts, but do not actually participate in the program. Accordingly, there are no Program Costs associated with the spillover effects.[12] 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 modified 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 Modified TRC Test Calculation

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

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

- The Avoided Costs;
- The 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 modified 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 "modified 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 modified TRC

[12] 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.

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.[13]

The modified 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 modified TRC test, these programs should be screened using a lower threshold value of 0.70 instead.[14]

The modified TRC ratio is expressed mathematically below:

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

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 = Avoid 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)

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

[14] 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.

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 section 51.1 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 section 51.2 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 6.2.3)

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residents, avoided homelessness and dislocation, and reductions in school dropouts from low-income families.

Some multi-year DSM programs may involve an initial ramp-up in the first year(s) and/or may be developed during the multi-year plan and introduced "mid" or "late" term. Accordingly, when screening such a program on an annual basis, the lifetime benefits of the measures installed in the first year of the program may not outweigh the costs associated with that program's first year. Such programs, which may result in net benefits over their entire life, but not necessarily so in their first year(s), would therefore end up being screened out if screened on a one-year basis. For this reason, the screening test of those programs can be applied on a multi-year basis as opposed to an annual basis (i.e., based on the lifetime benefits and costs accruing over all of the program's years). This provision will apply as well to programs which are introduced in the last year of the three-year plan period.

A natural gas utility should provide the modified TRC test results for all the programs it is seeking to get approved, except for those programs not amenable to that test.

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 and Deployment ("RD&D") and Pilot Programs

RD&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 four objectives outlined in section 3:
  - Maximization of cost effective natural gas savings;
  - Provision of equitable access to DSM programs among and across all rate classes to the extent reasonable, including access to low-income customers;
  - Prevention of lost opportunities; and
  - Pursuit of deep 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 modified 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), and of avoided CO2e emissions are referred to as "avoided costs".

6.1 Input Assumptions

The Board will oversee the annual review, update and approval of the common set of measure assumptions for prescriptive programs using an independent consultant and interested participants will be provided with an opportunity to comment on those inputs before they are finalized.[15] These 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

[15] The current common set of input assumptions, to be reviewed and updated for the purpose of the new DSM framework, is based on the Navigant Consulting Inc. report entitled Measures and Assumptions for Demand Side Management (DSM) Planning dated April 16, 2009 as well as any updates and additions to that set of input assumptions that arose from the evaluation and audit process outlined in the Board's Phase I Decision of the 2006 generic DSM proceeding (EB-2006-0021).

for Union and Enbridge may be provided to account for differences in their service areas.

The approved revised and updated set of input assumptions will be posted on the Board's website.

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 have happened 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 generally 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 the stakeholder engagement process, the natural gas utilities should jointly consider whether any updates and/or additions to the set of approved input assumptions are 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, or they may 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 utility's Draft Evaluation Report.[16] The application should be made annually, whether or not the natural gas utility is requesting any changes to the set of input assumptions. The natural gas utility's annual application will provide a Board forum for

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[16] 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.

stakeholders that will allow them, among other things, to request updates and/or additions to the set of input assumptions that may not have been identified by the natural gas utility.

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 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 for the 2012 program year should be based on the updated input assumptions resulting from the evaluation and audit of the 2012 results. The update to the input assumptions resulting from the evaluation and audit of the 2012 results would likely be completed in the second half of 2013.

The evaluation of the achieved results for the purpose of determining the incentive amounts should be based on the input assumptions approved by the Board for use in a given year. For example, where the Board has approved input assumptions for use in 2012, those input assumptions will be used for the purposes of determining the incentive for the 2012 program year, notwithstanding any updated input assumptions resulting from the Board's annual process following the evaluation and audit of the 2012 results. This is necessary because the target set for each natural gas utility is based upon the input assumptions approved by the Board for the year in question. If the input assumptions are updated for the purposes of determining a program year's result, it would also be necessary to amend the targets for the year in question using the updated input assumptions. This step is administratively unnecessary and of no informational value.

Further, assumptions updated through the Board's annual process will apply to program results in the month immediately following. For example, if the Board's process confirms an assumption change in October, then the updated assumption will apply to program results beginning in November. Where feasible and economically practical, the preference to determine LRAM and incentive amounts should be to use calculated actual results as for custom projects, instead of input assumptions. For example, it may be feasible and economically practical to calculate 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), and of avoided CO_2e emissions are referred to as "avoided costs".

- 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.
- Avoided costs resulting from the reduction in CO_2e emissions.

As outlined in section 6.2.2 below, the avoided cost associated with the reduction in CO2e emissions is set at a common value for both natural gas utilities. However, each natural gas utility should calculate all other avoided costs to reflect their specific cost structure as well as the characteristics of their franchise area. In order to ensure consistency, the natural gas utilities should use a common methodology to determine their utility specific avoided costs. The natural gas utilities should also coordinate the timing for selecting commodity costs so that they are comparable.[17]

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

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

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

[17] Commodity costs include those for natural gas and, if applicable, for other resources such as electricity, water, heating fuel oil and propane.
[18] The avoided cost assumptions currently used by the OPA are provided in the *OPA conservation and Demand Management Cost Effectiveness Guide*, dated October 15, 2010.

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 Costs of Carbon Dioxide Equivalent ("CO_2e") Emissions

For the purpose of these natural gas DSM guidelines, the value for avoided CO_2e emissions will be set by the Board based upon the submissions of stakeholders. Staff recommends that this value be maintained for the duration of the multi-year plan term. If market developments warrant re-examining this value during the term of the plan, this re-examination could occur as part of the annual process to update input assumptions.

The value for CO_2e emissions should only be used for DSM program screening purposes (i.e., to determine whether they should be considered at all for inclusion in the final DSM portfolio).

6.2.3 Discount Rate

For the purpose of the modified TRC test, the total avoided costs resulting over the life of the DSM measures need to be discounted to a present value. For the purpose of these natural gas DSM Guidelines, the common discount rate is to be determined by the Board in light of stakeholder comments and fixed for the duration of the three-year term of the plan. At the end of the three-year term, the Board may wish to consider updating the discount rate.

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 utility 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.

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 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 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."[19] 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. Spillover, as a practical matter, cancels out the impact of free ridership.

Given the limitations, including the cost, qualitative nature of the work, and growing customer survey fatigue, as recommended by CEA, the impact of free ridership will be deemed to be fully offset by the impact of spillover.

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.

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

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 the agreement reached between the parties prior to the program's launch.

Where a natural gas utility's allocated share in the agreement is 40% greater than the share that would have been allocated based on a "percentage of total dollars spent" basis, an explanation for the difference should be provided.[20]

In the absence of an 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 utility, on a fully allocated basis, subject to the natural gas utilities demonstrating otherwise.

Where programs will bring other benefits which the partners are seeking, e.g., electricity or water savings, the natural gas utilities may claim 100% of the gas savings as for partnerships with LDCs.

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).

Considerations relating to situations where the program may have accelerated the customer's decision to purchase energy efficient equipment are more appropriately reviewed as part of a free ridership assessment. Another important consideration in assessing the persistence of savings is potential changes in usage pattern. For example, large custom commercial and industrial DSM projects with expected useful life of 20 years or more may not fully materialize if the business benefiting from the custom measure operates at lower levels or closes down its processes within that time period. The opposite could also be true: the business operates at higher than forecast levels and/or expands. Despite the 15 years of experience natural gas utilities have delivering natural gas DSM programs in Ontario, requiring the utilities to undertake an assessment of the historical persistence of savings of custom DSM projects and commercial and

[20] 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 70% or less, an explanation should be provided to justify why the 50% share is more reflective of the gas utility's actual contribution.

industrial DSM programs in general is a new requirement that will require a great deal of thought and work before being implemented to the extent appropriate.

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%. The natural gas utilities should seek expert guidance to determine the extent to which any persistence factors should be developed for each program.

8. BUDGETS

To provide increased certainty to all involved in terms of funding and potential rate impact from one year to the next, DSM budget paths should be established at the outset of the multi-year DSM plan term. It is expected that multi-year funding will support better planning and management, and will also be more conducive to developing partnerships. Annual budget amounts will be an input to each year's distribution rate adjustment.

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.

The recommended natural gas DSM budget paths for Enbridge and Union are outlined in Table 1 below. The 2014 DSM budgets are expected to represent about 6% of Enbridge and Union's respective distribution revenues. These DSM budget paths are based on a 30% per year increase of Enbridge's approved 2011 DSM budget and a 15% per year increase of Union's approved 2011 DSM budget.

Table 1 – Target DSM Budgets ($ million)

	Approved	**Target**		
	2011	**2012**	**2013**	**2014**
Enbridge	28	36	47	62
Union	27	31	36	42

The recommended DSM budgets paths have been informed by the following five guiding principles:

(A) Supporting an increase emphasis on deep measures;

(B) Ensuring equitable access to DSM programs among and across all rate classes to the extent

(C) Increasing coordination and integration of certain natural gas DSM programs with electricity CDM programs;

(D) Ensuring no undue rate impacts; and

(E) Ensuring no undue level of cross-subsidization within and across rate classes.

The recommended DSM budget paths are targets. To increase or maintain their DSM budgets in accordance with those paths, the natural gas utilities will need to provide supporting evidence that they can cost effectively roll out those programs. Among other things, this evidence could be based on historical results of their DSM programs and market potential studies.

The target DSM budgets shown in Table 1 represent the amount to be funded through the natural gas utilities regulated distribution rates. Those DSM budget levels could be supplemented by other parties, such as the Ontario government, through alternative sources of funding.

It is expected that the recommended DSM budget levels outlined in Table 1 will allow the natural gas utilities to rationally increase their focus on deep measures while maintaining or increasing the number of participants reached. It should also provide support to increase the level of coordination between natural gas DSM and electricity CDM programs.

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 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. More specifically, upon requesting and receiving the required Board approval, the natural gas utilities may re-allocate funds to new DSM programs that are not part of the natural gas utility's Board-approved multi-year DSM plan.

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 currently receive the largest share of the natural gas DSM budget and its allocated budget should be sufficient to support the increase focus on deep measures while maintaining an equitable access to DSM programs among and across all rate classes, to the extent reasonable. 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 Low-Income Programs

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 application.

The natural gas utilities should consult with their stakeholders to determine appropriate low-income DSM budget levels 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.

As part of their multi-year DSM plan application and for information purposes, the natural gas utilities should submit an update of the estimated share of the residential rate classes' revenues derived from their low-income consumers. 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).

8.3 Budget for Market Transformation Programs

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.

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.

8.4 Budget for Research, Development and Deployment and Pilot Programs

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

8.5 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 its stakeholder engagement process, have to responsibility to propose appropriate EM&V requirements and the ensuing budget.

9. METRICS

Metrics refer to standard of measurements used to assess the results of DSM programs. For example, cubic meters (m3) 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 four guiding principles outlined earlier in section 3:

- Maximization of cost effective natural gas savings;
- Provision of equitable access to DSM programs among and across all rate classes, to the extent reasonable, including access to low-income customers;
- Prevention of lost opportunities; and
- Pursuit of deep 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 natural gas saved;
- $ spent per m^3 of natural gas saved; and
- Number of participants that receive at least one deep measure.[21]

The natural gas utilities, as informed through its stakeholder engagement process, 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 m3 of natural gas saved should be used instead. Likewise, the inclusion of a metric based on reduction of GHG emissions is not recommended as this metric would strongly, if not perfectly, correlate with m^3 savings of natural gas.

It is recognized that, under a budget constraint, rewarding the highest level of natural gas savings and going beyond a target deployment of deep measures will drive cost

[21] 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.

efficiency. However, it is expected that an explicit cost-efficiency measure, such as the "\$ spent per m^3 of 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.

To maintain equitable access to DSM programs among and across all rate classes to the extent reasonable, some programs within the portfolio of resource acquisition programs may have to be "shallower" in nature.[22] It is recognized that if an individual program's scorecard is developed for such programs, a metric on the "number of participants that receive at least one deep measure" would not be applicable to it.

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 savings of natural gas;
- \$ spent per m^3 of natural gas saved; and
- Number of participants that receive at least one deep measure.[23]

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

To maintain equitable access to DSM programs among and across all rate classes to the extent reasonable, some programs within the portfolio of low-income programs may have to be "shallower" in nature. It is recognized that if an individual program's scorecard is developed for such programs, a metric on the "number of participants that receive at least one deep measure" would not be applicable to it.

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 natural gas" metric should be included in market transformation program scorecard(s), along with a "\$ spent per m^3 of 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

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[22] "Shallow" programs are characterized by modest energy savings or a short-term focus. Examples include the deployment of energy efficient showerheads and faucet aerators. "Shallower" programs are less costly than deep measures, such as improving wall insulation, and can therefore be offered to a larger number of participants for a given budget amount.

[23] Ibid

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.

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 m3 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 DSM plan filing.

Adjustments to targets for years 2 and 3 of the plan may be made in consultation with stakeholders and filed with the Board in the first quarter of each year.

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 its stakeholder engagement process. 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 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.

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.[24] 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 utility's return on equity for the purposes of setting rates or in the calculation of any earnings sharing amounts.

The current incentive available to the natural gas utilities consists of the cap approved as part of the Generic Proceeding of $8.5 million escalated by the CPI. For 2011, the cap, with inflation, is calculated at $9.243367 million. In addition, the utilities are eligible for an incentive of up to $.5 million for market transformation programs, and up to a maximum of $600,000 for low-income weatherization. The aggregate of these amounts is $10.34 million.

The above figure is the incentive payable at the 150% level. The incentive payable at the 100% level in 2011 consists of $4.75 million for resource acquisition, $500,000 for market transformation, and $400,000 for low income weatherization, for a total of $5.65 million. To reflect the additional effort that will be required of the natural gas utilities, the incentive at the 100% level shall be increased by 15% in each year of the plan such that the incentive available in each year will be:

	($million)
2011 (current)	$ 5.65
2012	$ 6.50
2013	$ 7.47
2014	$ 8.59

To the extent that a natural gas utility does not increase the DSM Budget to the levels contemplated in the Guideline at Section 8 ("Budget"), then the incentive amount available at the 100% target will be reduced rateably. For example, if Enbridge increases its budget by 15% in 2012 instead of 30% (i.e., half of what is contemplated in this Guideline), then the increase in the incentive payable should increase by half of 15%, or 7.5%.

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[24] 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."

The incentive shall become payable beginning with the first percentage of results and will be calculated upwards on a linear basis.

There will be an incentive for each of the three DSM program types (i.e., resource acquisition, low income, and market transformation programs). The incentive amounts allocable to each of these program types will be 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 incentive payable in the year in question.

Incentive amounts paid to the natural gas utility 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.

If NRG wishes to undertake distribution-rate funded DSM activities, NRG should consult with the intervenors in its most recent rate case to determine whether any incentive amount is required and, if so, what the appropriate level should be.

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.

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.[25] 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.

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[25] 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.

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 annual impact for the first year of the DSM programs as 50% of the annual volumetric impact, multiplied by the distribution rate for each of the rate classes in which the volumetric variance occurred.

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 are 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-year DSM plan. Therefore, the amounts in all DSM variance or deferral accounts should be recorded on an annual basis.

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 utility's 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. 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 achieves its weighted scorecard target(s) (i.e., 100%) on a pre-audited basis for the program type; 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 annual impact for the first year of the DSM programs as 50% of the annual volumetric impact multiplied by the distribution rate for each of the rate classes in which volumistic variance occurred, 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 utility should apply annually for disposition of the balance in its 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 the 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 utility should apply annually for disposition of the balance in its DSMIDA, together with carrying charges, after the completion of the annual third party audit (see section 14).

Incentive amounts paid to the natural gas utility 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) are 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 utility's 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[26] 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.

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

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 utility in consultation with its stakeholders through the stakeholder engagement process. 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-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 application should include an Evaluation Plan. Approval of the natural gas utility's DSM plan will be conditional upon approval of an acceptable Evaluation Plan.

The Evaluation Plan should outline the natural gas utility's 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 utility 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 utility's responsibility to ensure that those objectives are addressed for all of its DSM programs, including those delivered in partnership and those delivered for the natural gas utility 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 its stakeholder engagement process, have the responsibility to propose appropriate monitoring and EM&V requirements. The stakeholder engagement process should set out what the formal channel will be for the gas utility's stakeholders, or a subcommittee thereof, to engage in the development of an evaluation plan and budget.

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 an engineering assessment of the savings. This assessment would serve as the primary documentation for the savings claimed.

A special assessment program (the custom project engineering review) should be proposed and implemented for custom projects. Typically, the assessment should be conducted on a random sample representing 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). To the extent 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.[27]

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 utility should provide an overview of the effectiveness of its 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 utility should report on all initiatives worked on and detail the process and impact analysis conducted for the individual programs.

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 utility should include, as an appendix to its Evaluation Report, the verifications studies provided by its third party evaluators and any other relevant research and evaluation documents.

For RD&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 utility should provide its own values, if available, and report all other relevant information.

If the input assumptions used by the natural gas utility 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

[27] The OPA's evaluation, measurement and evaluation documents can be found on the OPA's website at: http://archive.powerauthority.on.ca/Page.asp?PageID=122&ContentID=6484&SiteNodeID=404

completion of the program year and that such information will include the results from the third party evaluations.

If the specific technology promoted by a natural gas utility is not included on the input assumptions list, the natural gas utility may select a similar technology as a proxy. In this case, the natural gas utility should identify the actual technology in its Evaluation Report and the similarities between the proxy technology and the actual technology. The natural gas utility 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 details about the steps the natural gas utility has taken, or will take, to determine the actual data for the technology used in the DSM program going forward.

The natural gas utility 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 utility should also indicate in its Evaluation Report what has been 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 of its stakeholder engagement process, the natural gas utility should be responsible to select an independent third party auditor, determine the scope of the audit, and oversee the audit of their Draft Evaluation Report. The third party auditor, although hired by the natural gas utility, 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 utility and any amendment thereto;
- Verify the financial results in the Draft Evaluation Report to the extent necessary to express an 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 it fulfills its 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.[28] 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 utility 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 gas utility's stakeholders, or a subcommittee thereof, will review the revised Evaluation Report and the natural gas utility's responses to the Audit Report. The natural gas utility will consider any additional inputs resulting from its 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 its 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 its overall DSM budget for stakeholder engagement, based on anticipated needs.

16.1 Stakeholder Engagement Process

Stakeholders are involved in the natural gas utilities' DSM activities through various Board processes and through each utility's DSM stakeholder engagement process. Board processes include the ability to participate in proceedings relating to:

a) application for approval of the DSM multi-year plan;

[28] 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."

b) annual application for approval of updates to inputs and assumptions or assumptions relating to new measures;

c) annual application for clearance of DSM Variance Accounts; and

d) any mid-term applications for approval.

The utilities' stakeholder engagement process arises in respect of:

a) the development of the DSM plan; and

b) the annual DSM audit.

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 utility's 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 utility's 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 utility's 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 utility and its 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.[29] The ToR should also specify that Board staff may attend, as an observer, any stakeholder engagement meeting, including any subcommittee meetings.

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

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[29] 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.

- Development of the DSM Plan including budget, target and metrics;
- Selection of the independent auditor to audit the Draft Evaluation Report and determination of 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;
- Stakeholders, or a subcommittee thereof, should also be involved in the preparation of the natural gas utility's 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 utility 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.

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 Revised Draft DSM 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 utility's 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 utility's 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 a natural gas utility should be shared equally between the shareholders and the ratepayers (50%/50%). No natural gas ratepayer funded financial incentive amount should be provided for electricity CDM activities undertaken by the natural gas utilities. Net revenues arising from CDM activities are unrelated to any incentive regulation earnings sharing ("ERM"). Such net revenues in no way impact the results of any ERM that arise out of non-DSM utility activities.

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 application and any request for changes thereof should be guided by the information below.

The natural gas utilities will be expected to follow the filing and reporting requirements outlined in these Revised Draft DSM Guidelines as 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 utility may, at its discretion, do additional market potential studies and/or update(s) during the term of its plan. The results of any such additional studies and/or update(s) should be shared with the natural gas utility's stakeholders through its stakeholder engagement process and added as an appendix to the 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 the 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 utility should provide its 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 modified TRC net savings and modified TRC ratio of the program.

4. The natural gas utility 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 m3 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 Process being used;

   b) A discussion of whether and how, to the natural gas utility's knowledge, the Process is being or has been used or tested by any other utilities. Where the Process is being used by another natural gas utility, a description of how the natural gas utility will coordinate or work with the other natural gas utility using or testing the Process 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) Changes beyond the control of the natural gas utilities which materially impact the plan, including program targets, delivery, monitoring and/or evaluation.

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 utility's Board approved DSM plan, the natural gas utility should apply for approval of the proposed new program(s) at the time at which it applies 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.

APPENDIX A:

Revised Draft Demand Side Management Guidelines for Natural Gas Utilities

EB-2008-0346

Date: ~~January 21,~~February 14, 2011

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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 that due to uncertainties relating to the Green Energy Act, it would not require the

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

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.

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

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[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.

[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.

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.

1.2 Overview of the Revised Draft DSM Guidelines

The Revised Draft DSM Guidelines outline a proposed framework for natural gas DSM programs that is not fundamentally different from the natural gas DSM framework that resulted from the 2006 Generic Proceeding. The Revised Draft DSM Guidelines do however propose changes in many areas of the framework to account for the experience gained over the years and the 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, as well as the CEA and PEG reports issued in March 2010. In addition, an attempt has been made to maintain consistency, where appropriate, with the Ontario electricity Conservation and Demand Management ("CDM") framework. In particular, an attempt has been made to take into account the results of the Ontario Power Authority's ("OPA") consultations on the 2011-2014 province-wide electricity CDM programs as well as the recent Board consultations on electricity CDM.[4]

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 and, following consultation with the natural gas utilities about appropriate budgets, targets and incentives, if the Board is satisfied that the natural gas DSM framework remains appropriate, the Board could extend its term, subject to appropriate program-specific exceptions for programs that require multi-year terms beyond the extension.

3. PROGRAM AND PORTFOLIO DESIGN

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

- Maximization of cost effective natural gas savings;
- Provision of equitable access to DSM programs among and across all rate ~~classes~~class sectors (i.e., residential (including Low Income), commercial and Industrial) to the extent reasonable, including access to low-income customers;

[4] Ontario Energy Board consultations on a Conservation and Demand Management Code for Electricity Distributors (EB-2010-0215) and on Electricity Conservation and Demand Management Targets (EB-2010-0216).

- Prevention of lost opportunities[5]; and
- Pursuit of deep energy savings.[6]

The natural gas utilities may pursue DSM activities that support fuel-switching away from natural gas where these activities align with the above four DSM objectives and contribute to a net reduction in greenhouse gases. Fuel-switching to natural gas is not a DSM activity and DSM funds should not be used for this purpose.

In addition to the above four 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 adequate flexibility in DSM program and portfolio design is maintained, 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 four overarching guiding objectives is maintained and that proposed changes to the DSM plan is consistent with the other elements of the DSM framework, the natural gas utilities are required to seek approval to re-allocate funds to new programs that are not part of the natural gas utility's Board-approved DSM plan. ~~The natural gas utilities are also required to apply for Board approval 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.~~

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. ~~Research and~~In addition, research, development and deployment 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~~a designated budget.

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 Star appliances, programmable thermostats, efficient furnaces, hot water heaters, window replacement and attic insulation~~energy efficient space or water heating equipment or building envelope upgrades. Programs designed for small businesses

[5] 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.

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

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 and some larger commercial customers, solutions for those customers tend to be custom designed measures.

Custom projects are those projects that involve customized design and engineering, and where the natural gas utility facilitates the implementation of specialized equipment or technology not identified in the Board approved list of input assumptions. Projects that ~~involve~~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.[7] 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 programs, 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.

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) ~~(a)~~ Be accessible province-wide in the long term;

    b) ~~(b)~~ Require no upfront cost to the low-income energy consumer and result in an improvement in energy efficiency within the consumer's residence;

    c) ~~(c)~~ Address non-financial barriers (e.g. communication, cultural and linguistic).

2. Be delivered in a cost-effective manner;

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[7] 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.

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

5. Be a direct install program;

    a) ~~(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) ~~(b)~~ Emphasize deep measures that may include, where applicable, energy efficiency, demand response, fuel-switching, customer based generation and renewables;

    c) ~~(c)~~ Capture potential lost opportunities for energy savings, including new construction of low-income/affordable housing.

6. Provide an education and training strategy;

    a) ~~(a)~~ Encourage behaviour change of program participants toward a culture of conservation;

    b) ~~(b)~~ Help low-income energy consumers help themselves;

    c) ~~(c)~~ Help program participants to understand the benefits of participating in the low-income DSM program and conservation, in general;

    d) ~~(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) ~~(a)~~ Design programs that encourage persistence of energy savings.

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

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) ~~(a)~~ Be comprised of multi-year programs;

    b) ~~(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 the 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 consumer consistent with those established by the OPA's should be followed. 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 will be the responsibility of the natural gas utility, through their agent responsible for low-income program eligibility screening, to confirm participant eligibility.

1. Income Eligibility Criterion

The low-income natural gas DSM program income eligibility criterion requires meeting at least one of the following four criteria:

    a) ~~(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;

b) ~~(b)~~ Primary or secondary name on utility bill is a recipient of one of the following social benefits:

i) ~~(i)~~ The National Child Benefit Supplement;

ii) ~~(ii)~~ Allowance for the Survivor;

iii) ~~(iii)~~ Guaranteed Income Supplement;

iv) ~~(iv)~~ Allowance for Seniors;

v) ~~(v)~~ Ontario Works; or

vi) ~~(vi)~~ Ontario Disability Support Program.

c) ~~(c)~~ All social and assisted housing units are eligible for low-income natural gas DSM programs. 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) ~~(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 its 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 assisted housing. All residents of social and 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) ~~(a)~~ Private building residents: Tenants living in privately rented homes must obtain the consent of their landlord to participate in the program.

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

i) ~~(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);

ii) ~~(ii)~~ If a social and assisted housing resident identifies themselves to the program, the natural gas utility (or its delegates) will either direct the resident to contact their housing provider, or the natural gas utility (or its 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 ~~tend to~~can be ~~more~~ 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.

~~DSM activities funded through regulated rates should be limited to niches within the realm of market~~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 ~~should~~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~~or output-based (e.g., delivering a given number of workshops).

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

~~R~~RD&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 generics types of natural gas DSM program (i.e., resource acquisition, low-income, and market transformation~~a dedicated budget, the amount to be determined through development of the multi-year plan. RD&D and pilot programs~~)~~ are not subject to scorecard targets or incentives.

A pilot program is one that involves the installation, testing and/or evaluation of technologies, methodologies or arrangements (hereinafter jointly "Process") that are not already in use in Ontario, or in limited use, and that serves as a tentative model for future development. 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 a natural gas utility to fund a DSM R&D or pilot program should include a rationale for how its program will increase the collective understanding of a ~~technology~~Process and its benefits as a DSM measure. Where the R&D or pilot program involves a non-cost effective ~~technology~~Process, the onus will be on the natural gas utility 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~~Process is already being, or has been, installed, tested, used or evaluated by another utility, a natural gas utility that wishes to implement an R&D or pilot program using the same ~~technology~~Process will need to show how its program will result in additional benefits and how it 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 as to the appropriate development and delivery of future programs. Such activities would not be subject to scorecard evaluation nor 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 modified total resource cost test ("modified TRC"), as further explained below. To the extent that not all candidate programs that have passed the screening test can be undertaken due to budget constraints, prioritization among those programs must then 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. All other natural gas DSM programs should be screened using the total resource cost ("TRC") test, as modified to include a value for the reduction in greenhouse gases ("GHG") emissions as measured in tonnes (1,000 kg) of carbon dioxide equivalent emissions ("CO_2e"). 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 modified TRC test.

The modified TRC test measures the benefits and costs of DSM programs from a societal perspective 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, and the reduction in CO_2e emissions. Avoided costs are further described in section 6.2.

The costs considered in the modified 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 modified 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 the natural gas utility's DSM programming efforts. Advanced replacements (typically larger custom type projects) 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 utility 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."[8] In contrast, spillover effects refer to customers that adopt energy

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

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 modified TRC test.[9] However, as discussed in the section 5.1.2, all Program Costs associated with free riders should be included in the modified TRC analysis.

Spillover effects are essentially the mirror image of free ridership. Net Equipment Costs associated with spillover effects are included in the modified TRC test.[10] 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 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 modified TRC test, the Program Costs relate to DSM program include the following components:

i) ~~(i)~~ Development and Start-up;

ii) ~~(ii)~~ Promotion;

iii) ~~(iii)~~ Delivery;

iv) ~~(iv)~~ Evaluation, Measurement and Verification ("EM&V") and Monitoring; and

v) ~~(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.

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[9] Eto, J, (1998) Guidelines for assessing the Value and Cost-effectiveness of Regional Market Transformation Initiatives. Northeast Energy Efficiency Partnership, Inc.

[10] Ibid.

Incentive costs are not included in Program Costs. Incentive costs may include cash incentives, in-kind contributions and/or tax benefits provided to participants to encourage the implementation of a DSM measure. Incentive costs are a transfer from a program-sponsoring organization to participating customers and consequently do not impact the net benefit or cost from a societal perspective. As the modified 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) ~~(i) Development and~~

Start-up Costs

~~Costs of developing DSM plans and procedures are often concentrated in the early program years. In addition to development costs, the~~ 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 the 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) ~~(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.[11]

iii) ~~(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) ~~(iv) EM&V~~Evaluation, Verification 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~~Evaluation costs ~~will be assigned directly~~relating 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.~~are allocated to the program.

v) ~~(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

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

should include all staff salaries that are attributable to DSM programs as part of their Program Costs. For clarity, it is not practical to allocate administrative costs to individual programs. These costs will continue to be accounted at the portfolio level.

Program Costs should be considered as part of the modified TRC test for as long as they persist (e.g., ~~monitoring and EM&V~~verification 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 modified TRC analysis. Programs that have high free ridership rates will be less cost effective (as measured by the modified TRC test) since their Program Costs will be included in the analysis while their benefits will not.

The spillover effects are associated with customers that adopt energy efficiency measures because they are influenced by a utility's program-related information and marketing efforts, but do not actually participate in the program. Accordingly, there are no Program Costs associated with the spillover effects.[12] 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 modified 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 Modified TRC Test Calculation

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

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

- The Avoided Costs;
- The 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 modified 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.

[12] 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.

If the ratio of the PV of benefits to the PV of the costs (the "modified 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 modified TRC ratio for a program falls below 1.0, the program would be screened out and no longer ~~consider~~considered for inclusion as part of the DSM portfolio.[13]

The modified 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 modified TRC test, these programs should be screened using a lower threshold value of 0.70 instead.[14]

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

[14] 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 modified TRC ratio is expressed mathematically below:

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

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	=	Avoid 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 section 51.1 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 section 51.2 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 6.2.3)

residents, avoided homelessness and dislocation, and reductions in school dropouts from low-income families.

Some multi-year DSM programs may involve an initial ramp-up in the first year(s) and/or may be developed during the multi-year plan and introduced “mid” or “late” term. Accordingly, when screening such a program on an annual basis, the lifetime benefits of the measures installed in the first year of the program may not outweigh the costs associated with that program’s first year. Such programs, which may result in net benefits over their entire life, but not necessarily so in their first year(s), would therefore end up being screened out if screened on a one-year basis. For this reason, the screening test of those programs can be applied on a multi-year basis as opposed to an annual basis (i.e., based on the lifetime benefits and costs accruing over all of the program’s years). ~~The natural gas utilities should indicate which programs, if any, passed the multi-year screening test but would not have otherwise passed the test if screened on a one-year basis~~This provision will apply as well to programs which are introduced in the last year of the three-year plan period.

A natural gas utility should provide the modified TRC test results for all the programs it is seeking to get approved, except for those programs not amenable to that test.

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 and Deployment (“~~R~~RD&D”) and Pilot Programs

~~R~~RD&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 four objectives outlined in section 3:
  - Maximization of cost effective natural gas savings;
  - Provision of equitable access to DSM programs among and across all rate classes to the extent reasonable, including access to low-income customers;
  - Prevention of lost opportunities; and
  - Pursuit of deep 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 modified 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), and of avoided CO2e emissions are referred to as "avoided costs".

6.1 Input Assumptions

The Board will oversee the annual review~~ and~~, update ~~to~~and approval of the common set of measure assumptions for prescriptive programs using an independent consultant and interested participants will be provided with an opportunity to comment on those inputs before they are finalized.[15] These 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 Union and Enbridge may be provided to account for differences in their service areas.

The approved revised and updated set of input assumptions will be posted on the Board's website.

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 have happened 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 generally characterized by three general decision types: new, replacement, or retrofit.

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[15] The current common set of input assumptions, to be reviewed and updated for the purpose of the new DSM framework, is based on the Navigant Consulting Inc. report entitled Measures and Assumptions for Demand Side Management (DSM) Planning dated April 16, 2009 as well as any updates and additions to that set of input assumptions that arose from the evaluation and audit process outlined in the Board's Phase I Decision of the 2006 generic DSM proceeding (EB-2006-0021).

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 the stakeholder engagement process, the natural gas utilities should jointly consider whether any updates and/or additions to the set of approved input assumptions are 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, or they may 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 utility's Draft Evaluation Report.[16] The application should be made annually, whether or not the natural gas utility is requesting any changes to the set of input assumptions. The natural gas utility's annual application will provide a Board forum for stakeholders that will allow them, among other things, to request updates and/or additions to the set of input assumptions that may not have been identified by the natural gas utility.

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 update to the input assumptions resulting from the evaluation and audit of the ~~2010~~2012 results would likely be completed in the second half of 2013.

The evaluation of the achieved results for the purpose of determining the incentive amounts should be based on the input assumptions approved by the Board for use in a

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[16] 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.

given year. For example, where the Board has approved input assumptions for use in 2012, those input assumptions will be used for the purposes of determining the incentive for the 2012 program year, notwithstanding any updated input assumptions resulting from the Board's annual process following the evaluation and audit of the 2012 results. This is necessary because the target set for each natural gas utility is based upon the input assumptions approved by the Board for the year in question. If the input assumptions are updated for the purposes of determining a program year's result, it would also be necessary to amend the targets for the year in question using the updated input assumptions. This step is administratively unnecessary and of no informational value.

Further, assumptions updated through the Board's annual process will apply to program results in the month immediately following. For example, if the Board's process confirms an assumption change in October, then the updated assumption will apply to program results beginning in November. Where feasible and economically practical, the preference to determine LRAM and incentive amounts should be to use ~~measured~~calculated actual results as for custom projects, instead of input assumptions. For example, it may be feasible and economically practical to ~~measure~~calculate 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), and of avoided CO_2e emissions are referred to as "avoided costs".

- 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.
- Avoided costs resulting from the reduction in CO_2e emissions.

As outlined in section 6.2.2 below, the avoided cost associated with the reduction in CO2e emissions is set at a common value for both natural gas utilities. However, each natural gas utility should calculate all other avoided costs to reflect their specific cost structure as well as the characteristics of their franchise area. In order to ensure consistency, the natural gas utilities should use a common methodology to determine their utility specific avoided costs. The natural gas utilities should also coordinate the timing for selecting commodity costs so that they are comparable.[17]

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

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

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 Costs of Carbon Dioxide Equivalent ("CO_2e") Emissions

For the purpose of these natural gas DSM guidelines, the value for avoided CO_2e emissions will be ~~deemed to be $15 per tonne (1,000 kg).~~set by the Board based upon the submissions of stakeholders. Staff recommends that this value be maintained~~ at $15 per tonne of CO_2e emissions~~ for the duration of the multi-year plan term. If market developments warrant re-examining this value during the term of the plan, this re-examination ~~may consider~~could occur as part of the annual process to update input assumptions.

The value for CO_2e emissions should only be used for DSM program screening purposes (i.e., to determine whether they should be considered at all for inclusion in the final DSM portfolio).

6.2.3 Discount Rate

For the purpose of the modified TRC test, the total avoided costs resulting over the life of the DSM measures need to be discounted to a present value. ~~The~~ For the purpose of these natural gas ~~utilities should use a~~DSM Guidelines, the common ~~social ~~discount rate~~ of~~

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

[18] The avoided cost assumptions currently used by the OPA are provided in the *OPA conservation and Demand Management Cost Effectiveness Guide*, dated October 15, 2010.

~~X.X% (*staff does not make a number-specific recommendation; it*~~ is to be determined by the Board in light of stakeholder comments~~). The common social discount rate should be~~ and fixed for the duration of the three-year term of the plan. At the end of the three-year term, the Board may wish to consider updating the ~~social~~ discount rate.

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 utility 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.

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."[19] 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. Spillover, as a practical matter, cancels out the impact of free ridership.

~~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 its applicable programs. In contrast, the natural gas utilities have the option to request the inclusion of spillover effects for any of its programs.~~

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

~~Any request for the Board to consider the spillover effects need to be supported by comprehensive and convincing empirical evidence which clearly quantify the spillover effects of a specific program has had on program savings and the natural gas utility's 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~~

Given the limitations, including the cost, qualitative nature of the work, and growing customer survey fatigue, as recommended by CEA, the impact of free ridership will be deemed to be fully offset by the impact of spillover.

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~~the agreement reached between the parties prior to the program's launch.

Where a natural gas utility's allocated share in the ~~partnership~~ agreement is ~~more~~40% greater 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.[20] ~~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 utility made to the program.~~

In the absence of ~~a partnership~~an 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 utility, on a fully allocated basis, subject to the natural gas utilities demonstrating otherwise.

~~The share allocated to the natural gas utility will be used to determine the credited achievement for each of the relevant metrics used to evaluate the program. For instance, if the 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~~

Where programs will bring other benefits which the partners are seeking, e.g., electricity or water savings, the natural gas utilities may claim 100% of the gas savings as for partnerships with LDCs.

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~~Considerations relating to situations where the 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~~may have accelerated the customer's decision to purchase energy efficient ~~equipments 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~~

[20] 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~~70% or less, an explanation should be provided to justify why the 50% share is more reflective of the gas utility's actual contribution.

~~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.~~equipment are more appropriately reviewed as part of a free ridership assessment. Another important consideration in assessing the persistence of savings is 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'~~The opposite could also be true: the business operates at higher than forecast levels and/or expands. Despite the 15 years of experience natural gas utilities have delivering natural gas DSM programs in Ontario, requiring the ~~natural gas~~ utilities ~~should~~to 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.~~is a new requirement that will require a great deal of thought and work before being implemented to the extent appropriate.

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 expert guidance ~~through its stakeholder engagement process~~ to determine the extent to which any persistence factors should be developed for each program.

8. BUDGETS

To provide increased certainty to all involved in terms of funding and potential rate impact from one year to the next, DSM budget paths should be established at the outset of the multi-year DSM plan term. It is expected that multi-year funding will support better planning and management, and will also be more conducive to developing partnerships. Annual budget amounts will be an input to each year's distribution rate adjustment.

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.

The recommended natural gas DSM budget paths for Enbridge and Union are outlined in Table 1 below. The 2014 DSM budgets are expected to represent about 6% of Enbridge and Union's respective distribution revenues. These DSM budget paths are based on a 30% per year increase of Enbridge's approved 2011 DSM budget and a 15% per year increase of Union's approved 2011 DSM budget.

Table 1 – Target DSM Budgets ($ million)

	Approved	Target		
	2011	**2012**	**2013**	**2014**
Enbridge	28	36	47	62
Union	27	31	36	42

The recommended DSM budgets paths have been informed by the following five guiding principles:

(A) Supporting an increase emphasis on deep measures;

(B) Ensuring equitable access to DSM programs among and across all rate classes to the extent

(C) Increasing coordination and integration of certain natural gas DSM programs with electricity CDM programs;

(D) Ensuring no undue rate impacts; and

(E) Ensuring no undue level of cross-subsidization within and across rate classes.

The recommended DSM budget paths are targets. To increase or maintain their DSM budgets in accordance with those paths, the natural gas utilities will need to provide supporting evidence that they can cost effectively roll out those programs. Among other things, this evidence could be based on historical results of their DSM programs and market potential studies.

The target DSM budgets shown in Table 1 represent the amount to be funded through the natural gas utilities regulated distribution rates. Those DSM budget levels could be supplemented by other parties, such as the Ontario government, through alternative sources of funding.

It is expected that the recommended DSM budget levels outlined in Table 1 will allow the natural gas utilities to rationally increase their focus on deep measures while maintaining or increasing the number of participants reached. It should also provide support to increase the level of coordination between natural gas DSM and electricity CDM programs.

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 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. More specifically, upon requesting and receiving the required Board approval, the natural gas utilities may re-allocate funds to new DSM programs that are not part of the natural gas utility's Board-approved multi-year DSM plan. ~~The natural gas utilities may also, without requesting prior Board approval, undertake cumulative fund transfers among Board-approved DSM programs of up to 29% of the approved annual DSM budget for an individual natural gas DSM program. If the natural gas utilities wish to perform cumulative fund transfers among Board-approved DSM programs in excess of 30% of the approved annual DSM budget for an individual natural gas DSM program, they must seek and obtain prior Board approval.~~

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~~currently receive the largest share of the natural gas DSM budget and its allocated budget should be sufficient to support the increase focus on deep measures while maintaining an equitable access to DSM programs among and across all rate classes, to the extent reasonable. 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 Low-Income Programs

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 application.

The natural gas utilities should consult with their stakeholders to determine appropriate low-income DSM budget levels 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.

As part of their multi-year DSM plan application and for information purposes, the natural gas utilities should submit an update of the estimated share of the residential rate classes' revenues derived from their low-income consumers. 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).

8.3 Budget for Market Transformation Programs

~~As explained in section 4.3, DSM activities funded through regulated rates should be limited to niches within the realm of market~~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~~.

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.

8.4 Budget for Research, Development and Deployment and Pilot Programs

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

8.5 ~~8.4~~ 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 its stakeholder engagement process, have to responsibility to propose appropriate EM&V requirements and the ensuing budget.

9. METRICS

Metrics refer to standard of measurements used to assess the results of DSM programs. For example, cubic meters (m3) 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 four guiding principles outlined earlier in section 3:

- Maximization of cost effective natural gas savings;

- Provision of equitable access to DSM programs among and across all rate classes, to the extent reasonable, including access to low-income customers;
- Prevention of lost opportunities; and
- Pursuit of deep 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 natural gas saved;
- $ spent per m^3 of natural gas saved; and
- Number of participants that receive at least one deep measure.[21]

The natural gas utilities, as informed through its stakeholder engagement process, 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 ~~and may propose additional metrics.~~ . However, the inclusion of a TRC or societal net savings metric is not recommended; a metric based on m3 of natural gas saved should be used instead. Likewise, the inclusion of a metric based on reduction of GHG emissions is not recommended as this metric would strongly, if not perfectly, correlate with m^3 savings of natural gas.

It is recognized that, under a budget constraint, rewarding the highest level of 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 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.

To maintain equitable access to DSM programs among and across all rate classes to the extent reasonable, some programs within the portfolio of resource acquisition programs may have to be "shallower" in nature.[22] It is recognized that if an individual program's scorecard is developed for such programs, a metric on the "number of participants that receive at least one deep measure" would not be ~~app~~applicable to it.

[21] 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.

[22] "Shallow" programs are characterized by modest energy savings or a short-term focus. Examples include the deployment of energy efficient showerheads and faucet aerators. "Shallower" programs are less costly than deep measures, such as improving wall insulation, and can therefore be offered to a larger number of participants for a given budget amount.

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 savings of natural gas;
- $ spent per m^3 of natural gas saved; and
- Number of participants that receive at least one deep measure.[23]

The natural gas utilities, as informed through its stakeholder engagement process, should propose the number and the organization of scorecards, the metrics used and the weight associated with each metric ~~and may propose additional metrics~~.

To maintain equitable access to DSM programs among and across all rate classes to the extent reasonable, some programs within the portfolio of low-income programs may have to be "shallower" in nature. It is recognized that if an individual program's scorecard is developed for such programs, a metric on the "number of participants that receive at least one deep measure" would not be applicable to it.

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 natural gas" metric should be included in market transformation program scorecard(s), along with a "$ spent per m^3 of 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.

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 m3 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

[23] Ibid

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 DSM plan filing.

Adjustments to targets for years 2 and 3 of the plan may be made in consultation with stakeholders and filed with the Board in the first quarter of each year.

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 its stakeholder engagement process. 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 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.

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.[24] 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 utility's return on equity for the purposes of setting rates or in the calculation of any earnings sharing amounts.

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[24] 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."

The ~~maximum~~current 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").[25] The DSM incentive payments are pre-tax~~to the natural gas utilities consists of the cap approved as part of the Generic Proceeding of $8.5 million escalated by the CPI. For 2011, the cap, with inflation, is calculated at $9.243367 million. In addition, the utilities are eligible for an incentive of up to $.5 million for market transformation programs, and up to a maximum of $600,000 for low-income weatherization. The aggregate of these amounts is $10.34 million.

~~If NRG wishes to undertake distribution-rate funded DSM activities, NRG should consult with the intervenors in its most recent rate case to determine whether any incentive amount is required and, if so, what the appropriate level should be.~~

~~To the extent that the *approved* DSM budgets deviate in magnitude from the proposed budget path outlined in Table 1, the Annual Cap should be scaled accordingly.[26] 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 above figure is the incentive payable at the 150% level. The incentive payable at the 100% level in 2011 consists of $4.75 million for resource acquisition, $500,000 for market transformation, and $400,000 for low income weatherization, for a total of $5.65 million. To reflect the additional effort that will be required of the natural gas utilities, the incentive at the 100% level shall be increased by 15% in each year of the plan such that the incentive available in each year will be:

	($million)
2011 (current)	$ 5.65
2012	$ 6.50
2013	$ 7.47
2014	$ 8.59

To the extent that a natural gas utility does not increase the DSM Budget to the levels contemplated in the Guideline at Section 8 ("Budget"), then the incentive amount available at the 100% target will be reduced rateably. For example, if Enbridge increases its budget by 15% in 2012 instead of 30% (i.e., half of what is contemplated in this Guideline), then the increase in the incentive payable should increase by half of 15%, or 7.5%.

~~[25] More specifically, the Annual Cap would be escalated using the Ontario Consumer Price Index as determined in October of the preceding year (i.e., the 2013 cap will increase based on CPI as determined at October of 2012).~~

~~[26] For instance, if the approved DSM budget is 25% less in a given year than the target budget path as shown in Table 1, the maximum incentive amount for that year will be reduced by 25%.~~

The incentive shall become payable beginning with the first percentage of results and will be calculated upwards on a linear basis.

~~The Annual Cap should be allocated among~~There will be an incentive for each of the three ~~generic~~DSM program types (i.e., resource acquisition, low~~-~~ income, and market transformation programs). The incentive amounts allocable to each of these program types will be 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 payable in the year in question.

Incentive amounts paid to the natural gas utility 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%, 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.~~[27]

~~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.~~[28] ~~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~~

If NRG wishes to undertake distribution-rate funded DSM activities, NRG should consult with the intervenors in its most recent rate case to determine whether any incentive amount is required and, if so, what the appropriate level should be.

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[27] ~~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%.~~

[28] ~~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.~~

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.

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.[~~29~~25] 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 annual impact for the first year ~~impact~~ of the DSM programs ~~on a monthly basis, based on the~~as 50% of the annual 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~~occurred.

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.

[~~29~~25] 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.

The recording of LRAM amounts and the disposition of the balance in the LRAM variance account are 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-year DSM plan. Therefore, the amounts in all DSM variance or deferral accounts should be recorded on an annual basis.

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 utility's 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~~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~~achieves 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~~ type; 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~~annual impact for the first year ~~impact of DSM programs on a monthly basis~~of the DSM programs as 50% of the annual volumetric impact multiplied by the distribution rate for each of the rate classes in which volumistic variance occurred, 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 utility should apply annually for disposition of the balance in its 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 the 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 utility should apply annually for disposition of the balance in its DSMIDA, together with carrying charges, after the completion of the annual third party audit (see section 14).

Incentive amounts paid to the natural gas utility 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) are 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 utility's 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[~~30~~26] 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 utility in consultation with its stakeholders through the stakeholder engagement process.

[~~30~~26] *The California Evaluation Framework*, TecMarket Works, June 2004, p. 28.

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-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 application should include an Evaluation Plan. Approval of the natural gas utility's DSM plan will be conditional upon approval of an acceptable Evaluation Plan.

The Evaluation Plan should outline the natural gas utility's 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 utility 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 utility's responsibility to ensure that those objectives are addressed for all of its DSM programs, including those delivered in partnership and those delivered for the natural gas utility 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 its stakeholder engagement process, have

~~to~~the responsibility to propose appropriate monitoring and EM&V requirements. The stakeholder engagement process should set out what the formal channel will be for the gas utility's 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~~an engineering assessment of the savings. This assessment would serve as the primary documentation for the savings claimed.

A special assessment program (the custom project engineering review) should be proposed and implemented for custom projects. ~~The~~Typically, the assessment should be conducted on a random sample ~~consisting of 10% of the large custom projects; and the projects should represent~~representing 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). To the extent 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.[~~31~~27]

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 utility should provide an overview of the effectiveness of its 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

[~~31~~27] The OPA's evaluation, measurement and evaluation documents can be found on the OPA's website at: http://archive.powerauthority.on.ca/Page.asp?PageID=122&ContentID=6484&SiteNodeID=404

activities associated with the program. The natural gas utility should report on all initiatives worked on and detail the process and impact analysis conducted for the individual programs.

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 utility should include, as an appendix to its Evaluation Report, the verifications studies provided by its third party evaluators and any other relevant research and evaluation documents.

For ~~R~~RD&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 utility should provide its own values, if available, and report all other relevant information.

If the input assumptions used by the natural gas utility 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 a natural gas utility is not included on the input assumptions list, the natural gas utility may select a similar technology as a proxy. In this case, the natural gas utility should identify the actual technology in its Evaluation Report and the similarities between the proxy technology and the actual technology. The natural gas utility 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 details about the steps the natural gas utility has taken, or will take, to determine the actual data for the technology used in the DSM program going forward.

The natural gas utility 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 utility should also indicate in its Evaluation Report what has been 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 of its stakeholder engagement process, the natural gas utility should be responsible to select an independent third party auditor, determine the scope of the audit, and oversee the audit of their Draft Evaluation Report. The third party auditor, although hired by the natural gas utility, 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 utility 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 it fulfills its 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.[~~32~~28] 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 utility 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 gas utility's stakeholders, or a subcommittee thereof, will review the revised Evaluation

[~~32~~28] 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."

Report and the natural gas utility's responses to the Audit Report. The natural gas utility will consider any additional inputs resulting from its 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 its 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 its overall DSM budget for stakeholder engagement, based on anticipated needs.

16.1 Stakeholder Engagement Process

Stakeholders are involved in the natural gas utilities' DSM activities through various Board processes and through each utility's DSM stakeholder engagement process. Board processes include the ability to participate in proceedings relating to:

a) application for approval of the DSM multi-year plan;

b) annual application for approval of updates to inputs and assumptions or assumptions relating to new measures;

c) annual application for clearance of DSM Variance Accounts; and

d) any mid-term applications for approval.

The utilities' stakeholder engagement process arises in respect of:

a) the development of the DSM plan; and

b) the annual DSM audit.

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 utility's 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 utility's 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 utility's 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 utility and its 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.[~~33~~29] The ToR should also specify that Board staff may attend, as an observer, any stakeholder engagement meeting, including any subcommittee meetings.

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

- ~~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;~~Development of the DSM Plan including budget, target and metrics;
- Selection of the independent auditor to audit the Draft Evaluation Report and determination of 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;
- Stakeholders, or a subcommittee thereof, should also be involved in the preparation of the natural gas utility's 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 utility 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.

[~~33~~29] 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 Revised Draft DSM 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 utility's 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 utility's 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 a natural gas utility should be shared equally between the shareholders and the ratepayers (50%/50%). No natural gas ratepayer funded financial incentive amount should be provided for electricity CDM activities undertaken by the natural gas utilities. Net revenues arising from CDM activities are unrelated to any incentive regulation earnings sharing ("ERM"). Such net revenues in no way impact the results of any ERM that arise out of non-DSM utility activities.

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 application and any request for changes thereof should be guided by the information below.

The natural gas utilities will be expected to follow the filing and reporting requirements outlined in these Revised Draft DSM Guidelines as 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 utility may, at its discretion, do additional market potential studies and/or update(s) during the term of its plan. The results of any such additional studies and/or update(s) should be shared with the natural gas utility's stakeholders through its stakeholder engagement process and added as an appendix to the 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 the natural gas utility's distribution system, including:

    a) ~~(a)~~ Total natural gas purchases;

    b) ~~(b)~~ Sales by rate class; and

    c) ~~(c)~~ Number of customers by rate class.

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

    a) ~~(a)~~ Detailed description of the program;

    b) ~~(b)~~ Customer class(es) targeted;

    c) ~~(c)~~ Projected annual incremental natural gas savings as well as other resource savings, if applicable;

    d) ~~(d)~~ Goals, including program metrics and scorecard;

    e) ~~(e)~~ Maximum shareholder financial incentive allocated to the program

    f) ~~(f)~~ Length;

    g) ~~(g)~~ Projected budget, listing:

i) ~~(i)~~ Description of the primary barriers preventing higher uptake of the measures of the program;

ii) ~~(ii)~~ Description of how the program will remove the barriers;

iii) ~~(iii)~~ Capital expenditures per year;

iv) ~~(iv)~~ Operating expenditures per year separated into direct and indirect expenditures;

v) ~~(v)~~ For each direct operating expenditure, an allocation of the expenditure by targeted customer classes; and

vi) ~~(vi)~~ Expenditures for evaluation of the program.

3. Program cost effectiveness results;

   a) ~~(a)~~ The input assumptions underlying the forecasted savings and costs including a detailed presentation of the calculations;

   b) ~~(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 utility should provide its own values, if available, and report all other relevant information;

   c) ~~(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) ~~(d)~~ Estimated Net Equipment and Program Costs; and

   e) ~~(e)~~ The benefit-cost analysis, calculating the modified TRC net savings and modified TRC ratio of the program.

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

   a) ~~(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) ~~(b)~~ A forecast of the number of customers in each class and a forecast of m3 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) ~~(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)~~ A description of the ~~technology~~Process being used;

   b) ~~(b)~~ A discussion of whether and how, to the natural gas utility's knowledge, the ~~technology~~Process is being or has been used or tested by any other utilities. Where the ~~technology~~Process is being used by another natural gas utility, a description of how the natural gas utility will coordinate or work with the other natural gas utility using or testing the ~~technology~~Process to ensure effective use of the program and of lessons learned; and

c) ~~(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.~~Changes beyond the control of the natural gas utilities which materially impact the plan, including program targets, delivery, monitoring and/or evaluation.

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 utility's Board approved DSM plan, the natural gas utility should apply for approval of the proposed new program(s) at the time at which it applies for the proposed budget reallocation.

   a) ~~(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.

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