TORONTO ATMOSPHERIC FUND

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Establishing a Conservation-First Policy for Ontario's Natural Gas Utilities

On March 31, 2014, the Minister of Energy directed the Ontario Energy Board (OEB) to develop a new demand side management (DSM) policy framework for natural gas that enables the achievement of all cost-effective conservation. This policy will set the stage for effective natural gas conservation practice in Ontario – key to achieving greenhouse gas reduction targets.

Toronto Atmospheric Fund (TAF) is a non-profit corporation established in 1992 and endowed by the City of Toronto. TAF's mandate is to advance urban solutions to climate change and air pollution. In Toronto, a primary source of greenhouse gas emissions is the use of natural gas in buildings, so the recent directive by the Ontario Minister of Energy provides a critical opportunity to help achieve greenhouse gas reduction targets in Toronto and across the Province. For more about TAF's mandate and accomplishments, please see our website at www.toronto.ca/taf

To support discussion around developing a new DSM framework, TAF has commissioned a series of papers on key issues relevant to implementing the Minister's "all cost-effective DSM" directive:

- Savings Goal and Budget Setting
- Cost-Effectiveness Screening
- Performance Measurement
- Performance Incentives
- Integration of Gas and Electricity Conservation Efforts
- Are Ontario Gas Utilities' Efficiency Programs Worth It?

As requested by OEB Applications Advisor Josh Wasylyk, TAF is filing these discussion papers with the OEB as reference materials for proceeding number EB-2014-0134, as they are relevant for the Board's consideration in its development of the new DSM framework.

The papers have been prepared for TAF by Chris Neme, Energy Futures Group, with research support from TAF's Policy Researcher, Rebecca Mallinson. The views and ideas expressed in these discussion papers are presented by the Toronto Atmospheric Fund to support the discussion around developing a new gas DSM policy framework.

For further information or for questions or comments on these discussion papers, please contact:

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Table of Contents

Summary of Discussion Paper Recommendations

Savings Goal and Budget Setting

- DSM savings goals should – in accordance with the Minister of Energy's directive – aim to realize all available cost-effective energy efficiency resources.
- To do this, savings targets should be informed by bottom-up DSM potential studies and by the experience of other jurisdictions with similar "all cost-effective conservation" goals.
- The experience of U.S. jurisdictions indicates that in order to achieve the mandate of pursuing all cost-effective gas DSM, Ontario's savings targets should be at least 1% of total gas sales, and DSM budgets should be at least $200 million per year (i.e. more than three times Ontario utilities' historical annual spending on DSM).

Cost Effectiveness Screening

- Two key principles should guide the selection and application of a primary cost-effectiveness test: 1) the test should reflect the policies of the jurisdiction in which it will be used, and 2) costs and benefits should be treated symmetrically.
- With respect to test selection, every cost-effectiveness test must include utility costs and benefits, but the types of additional benefits that are included should be a function of government policies relative to those impacts (i.e. participant impacts, additional low-income impacts, health impacts, climate change impacts, other environmental impacts, etc.).
- In light of Ontario government policies that indicate concern over all these impacts, it seems appropriate for Ontario to use a full societal cost test to assess DSM activities. At a minimum, given the government's clear targets for greenhouse gas (GHG) emission reductions, GHG emission externalities should be incorporated into cost-effectiveness screening.
- With respect to applying cost-effectiveness tests, if costs to DSM program participants are included in cost-effectiveness calculations, then benefits participants should also be included (at a minimum, by using default adders for non-resource, non-energy benefits).
- If benefits to participants are not included in cost-effectiveness calculations, then the participant perspective should be excluded from the analysis altogether. (This would be analogous to moving from a TRC test to a PAC test, or from a SCT to a PAC test with environmental externalities).

Performance Measurement

- At least once every three years, all DSM programs should undergo some form of impact evaluation; that includes not only key verification activities, but also some form of measurement (e.g. whole facility billing analysis, end use metering, calibrated building simulation modeling).
- Impact assessment of the very large custom C&I programs should continue to be conducted through the Custom Project Savings Verification (CPSV) process, but with increased emphasis on on-site measurement, and removing utilities from the role of hiring and overseeing CPSV firms.
- A minimum of 3% of DSM budgets should continue to be set aside for evaluation, with higher amounts to be encouraged if required in the short term to address key data uncertainties.
- The deadline for filing annual audit reports should be pushed back from the end of June to at least the end of July in order to facilitate more extensive field work by CPSV firms

Performance Incentives

- Hold Ontario's incentives to current levels or increase only very modestly, even if utilities' DSM budgets increase dramatically.
- Examine trends in Ontario gas utilities' recent incentive earnings to determine whether incentive thresholds are set at appropriate levels, and to ensure that utilities are only earning the maximum incentives for truly exemplary performance.
- Existing performance incentive metrics are generally consistent with best practice across North America, but would benefit from some adjustments:
    - Allocate each performance metric a portion of the incentive cap (in order to eliminate the problem of over-performance on easy metrics being able to compensate for poor performance on others).
    - Ensure that incentives meant to encourage deep savings are directed toward savings achievements in the neighbourhood of 30% in existing buildings and 20% better than code in new construction. Deep savings metrics might also need to be defined over a longer period that 1 year.
- Reintroduce a lost opportunity metric to ensure that programs are encouraging participants to pursue all available cost-effective conservation opportunities.
- Consider introducing a geo-targeting metric to reward utilities for geographically targeting DSM efforts in such a way as to avoid new investments in transmission and distribution infrastructure.

Gas-Electric Integration

- Collaboration can occur to varying degrees, from "coordination" (consistency in program design) to "integration" (joint delivery of programs).
- In addition to greater collaboration between gas and electricity utilities, there is also potential for greater collaboration between the two gas utilities.
- Potential benefits of coordinated and/or integrated DSM programs include: lower program costs, enhanced reach, greater clarity in the market, and lower transaction costs for consumers.
- Coordination and/or integration are most important for programs that target market transformation, mass markets, and multi-measure, whole-building retrofits.
- While it is neither practical nor desirable to require collaboration, the gas utilities could be required to explore/endeavour to collaborate on program design and delivery with the OPA and the six largest electric utilities, and to document these efforts in their DSM reports.
- The utilities should be required to examine fuel-switching options and encouraged to pursue opportunities that are cost-effective and reduce greenhouse gas emissions; for instance deployment of heat pumps for heating.

Are Ontario Gas Utilities' Energy Efficiency Programs Worth It?

- Conservation is much cheaper than supply – Enbridge and Union Gas' programs cost \$0.03 - \$0.06 per m^3 to save natural gas, which is much less than the \$0.30 to \$0.35 per m^3 it costs the average Ontario customer to buy it.
- The \$62 million Union and Enbridge Gas's spent on efficiency programs will save their customers approximately \$338 million (net) on their gas, electric and water bills.
- Delivering energy efficiency tends to be more labour-intensive than delivering gas, which means that investments in energy efficiency create local green jobs.
- Lower energy bills make businesses more competitive, and when consumers spend their energy bill savings in the wider economy, this also contributes to local economic development.
- The measures installed as a result of Enbridge and Union's 2012 energy efficiency programs will reduce carbon dioxide emissions by 6.4 million tonnes over the course of their lifetimes – this is equivalent to taking nearly one quarter of Ontario's cars and light trucks off the road for a year.
- Reducing natural gas use by just 1% per year starting in 2015 would lower GHG emissions by 2.4 megatonnes by 2020 and achieve about 15% of Ontario's 2020 GHG reduction target.

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2014 OEB Gas DSM Framework Issue Paper:

Savings Goal and Budget Setting

On March 31, 2014, the Ontario Energy Minister issued a Directive that the Ontario Energy Board (OEB) establish a new gas DSM framework that will enable the province's regulated gas utilities to acquire all cost-effective energy efficiency resources. Among the most important elements of that framework will be guidance on how both savings goals and DSM budgets for meeting those goals are to be established. This paper addresses those issues, making clear that savings and budget levels will need to increase substantially to comply with the Minister's directive.

Savings Goals

The Minister's directive clearly states that the goal should be to acquire all cost-effective efficiency resources. Thus, savings goals should be based on a determination of how much efficiency could be acquired. Since there is no single "formula" or even a single type of study or analysis for making that determination, some judgment is needed and that should be informed by several types of information including potential studies and the experience of other jurisdictions with similar objectives.

Potential Studies

Efficiency potential studies can be a useful tool for informing savings goals, as they provide an objective assessment of efficiency potential that is based on the size and characteristics of local markets for efficiency products and services.

However, they also have some important limitations. First, they produce inherently conservative results because, among other things, they cannot a) anticipate new efficiency technologies that will develop over time, b) anticipate reductions in the cost of efficiency measures that can develop over time, c) imagine the full range of custom efficiency measures for large commercial and industrial customers (i.e. measures whose application may be specific not only to a particular industry, but even to a particular facility), and d) anticipate innovations in the design and delivery of efficiency programs that can either reduce costs or increase effectiveness in acquiring savings.[1]

[1] For further discussion of these and other conservatisms see: Goldstein, David B., "Extreme Efficiency: How Far Can We Go If We Really Need To?", 2008 ACEEE Summer Study Proceedings, Volume 10, pp. 44-56

A related concern is that potential studies often rely on very simplistic ways of forecasting how much of the economic potential is actually "achievable". For example, many assume that market penetration is entirely a function of customer paybacks and make largely untested assumptions about customers' willingness to invest in efficiency at different payback periods. In reality, achievability is a function of the nature and severity of a variety of different market barriers – only some of which are financial – to the adoption of an efficiency technology. DSM experience also suggests addressing financial concerns is important, but other benefits of efficiency – including improved comfort, improved building durability, improved business productivity and many others – can often be used effectively to sell efficiency. Put simply, efficiency programs must be carefully designed to both address all market barriers and to leverage other benefits that efficiency measures offer – using a variety of tools including education, training, financial incentives, financing, labeling/certification, marketing, etc. It is important to recognize that the market barriers and market opportunities vary considerably from measure to measure and market to market. It is usually not possible – i.e. typically well beyond the budget available – for contractors conducting potential studies to separately assess all of the barriers and opportunities for all measures and to then separately develop market penetration estimates for each measure and market given the nature of those barriers. As a result, regulators in at least one jurisdiction (California) have simply assumed that 70% of economic potential can be captured.[2]

One possible additional and critically important limitation is that many efficiency potential studies rely on avoided costs that do not fully capture the value of efficiency (see TAF's companion paper on cost-effectiveness screening).

No gas efficiency potential studies have been recently completed in Ontario. The last Enbridge Gas Distribution potential study was completed in 2009 -- it suggested that maximum achievable potential was approximately 12% over a ten year period, an average of 1.2% per year.[3] The last Union Gas assessment of efficiency potential was a 2011 update to a 2008 study -- it estimated that maximum achievable potential was approximately 14% over a ten year period, an average of nearly 1.4% per year.[4] Both the Enbridge and Union studies assumed that only 46% of economic potential could be acquired through DSM. As noted above, that is lower than California regulators and other studies have suggested is possible. Also, neither

[2] California Public Utilities Commission, "Interim Opinion: Energy Efficiency Portfolio Plans and Program Funding Levels for 2006-2008 – Phase 1 Issues", Decision 05-09-043, September 22, 2005.
[3] Marbek Resource Consultants, "Natural Gas Energy Efficiency Potential: Update 2008", presented to Enbridge Gas Distribution, September 2009.
[4] ICF Marbek, "2008 Natural Gas Efficiency Potential Study with 2011 Summary Report Update", submitted to Union Gas, July 2011.

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study fully considered the savings potential from (typically) low cost operational efficiency improvements in commercial buildings, which can be substantial.[5]

In addition to the limitations discussed above, the most recent Ontario studies are now old enough that they cannot reflect changes in the understanding of gas efficiency potential. Moreover, it is not clear that the avoided costs they used to value the benefits of efficiency either fully valued all of the benefits of efficiency (e.g. the benefits of deferring capital investments in transmission and/or distribution); nor is it clear that the avoided cost values for the benefits that they did assess are appropriate for today's market conditions.

Enbridge Gas is currently conducting a new potential study. However, it is not clear whether the study will assess maximum achievable cost-effective potential because the terms of reference for the study were developed before the Ontario Energy Minister's directive was issued. The Minister's directive also requires that a study of achievable natural gas efficiency potential in Ontario be conducted every three years (in coordination with the Ontario Power Authority's assessment of electric efficiency potential). However, the next such study is not required to be completed until June 1, 2016. This likely limits the ability of the OEB and other parties to rely extensively on potential studies to inform goal setting for the near term (i.e. 2015).

Experience from Other Jurisdictions with Similar Objectives

Another important reference point for establishing "all cost-effective" savings goals should be the experience of other jurisdictions, particularly those also operating under an "all cost-effective" mandate and with similar climates[6]. Their experiences should be assessed both in aggregate – i.e. across all customers and sales – and at the sector level; the latter is important because achievable efficiency potential can vary substantially from sector to sector, particularly over short to medium time horizons. For example, savings potential in the industrial sector is often viewed as more substantial – at least in the short and medium terms – than potential in the residential sector.[7] Thus, utilities or jurisdictions with proportionally greater sales to residential customers will typically have lower total savings as a percent of total sales than utilities or jurisdictions with proportionally greater sales to industrial customers, particularly larger industrial customers.

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[5] See testimony from Environmental Defense witness Ian Jarvis in EB-2012-0451.

[6] Similar climates is important because much of gas use in residential and commercial buildings in northern climates is related to space heating.

[7] Residential savings potential is still quite substantial, but because it requires retrofit treatment of many more customers, it will take longer to fully acquire the potential.

Right now, there are only two other "cold climate jurisdictions" in North America that have a mandate to pursue all cost-effective gas DSM: Massachusetts and Rhode Island. Both of those jurisdictions are proposing to capture savings equal to about 1.1% of total (all sector) sales in their current plans for 2015.[8] Though not operating under an "all cost-effective" mandate, gas utilities in Vermont (1.1% in 2013) and Minnesota (1.5% in 2015 plans) have comparable savings levels (again, in aggregate across all sectors). In both Massachusetts and Rhode Island, approximately 50% of gas sales are to residential customers and only about 20% to industrial customers.[9] Gas sales in Ontario are less heavily weighted towards the residential sector and more heavily weighted towards the industrial sector. Thus, one would expect savings potential in Ontario to be higher than in Massachusetts and Rhode Island, at least in the short and medium term.

Budgets

Given the Ontario Energy Minister's directive, the budgets made available for DSM on Ontario should be sufficient to capture all cost-effective gas efficiency – i.e. to meet the savings targets discussed above. Ideally, the determination of how much money that would be would be based on "bottom up" assessments – market by market – of what state-of-the art energy efficiency programs would need to do, how they would be designed and the level of financial resources those designs would require to be as effective as possible. That said, the DSM budgets of other jurisdictions that are mandated and endeavoring to acquire all cost-effective gas efficiency potential (or even similarly aggressive levels of savings) can be used as a useful reference point.

Experience of Other Jurisdictions with Similar Objectives

Consider these four jurisdictions: two cold climate jurisdictions currently required to pursue all cost-effective gas efficiency resources -- Massachusetts and Rhode Island – and two others – Vermont and Minnesota – with at least comparable energy savings goals. As Table 1 shows, these four jurisdictions have annual DSM budgets that range from 3½ to 13 times (average of 8 times) greater than the current Ontario utility DSM budgets on a gas sales normalized basis. Put another way, if the Ontario gas utilities DSM budgets were to increase to levels comparable to those of leading jurisdictions, they would be at least $100 million per year per utility – at least $200 million for the province – and potentially several times that amount.

[8] Based on savings forecast in the utilities' most recently filed DSM plans and 2012 sales from the U.S. Energy Information Administration's form 176 data.
[9] U.S. Energy Information Administration data from EIA form 176 for calendar year 2012.

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Table 1: Leading Jurisdiction vs. Ontario DSM Budgets[10]

	Total Gas Sales (m^3)	Gas Sales Reference Year	Total DSM Budget	Budget Reference Year	DSM Budget per m^3 Sales
Leading Jurisdictions					
Massachusetts	6,319,346,456	2012	$ 191,766,032	2015	$0.0303
Minnesota	4,790,121,305	2012	$ 50,833,263	2015	$0.0106
Rhode Island	957,519,137	2012	$ 23,491,410	2014	$0.0245
Vermont	227,572,544	2012	$ 1,884,124	2013	$0.0083
Average					**$0.0184**
Ontario Utilities					
Enbridge	11,300,100,000	2012	$ 30,606,510	2012	$0.0027
Union	14,617,390,000	2012	$ 31,322,216	2012	$0.0021
Average					**$0.0024**

It is worth noting that many other jurisdictions across North America – including many who clearly do not have a mandate to pursue all cost-effective efficiency and are not attempting to even get close to that level of savings – have historically had DSM budgets that are considerably greater than the Ontario gas utilities' budgets. The spending metric used by the American Council for an Energy Efficient Economy (ACEEE) to compare gas DSM spending between states is: total spending per residential customer. In 2011, the Ontario gas utilities spent a combined $55.2 million on gas DSM.[11] That represents an average of about $15 per residential customer.[12] In the same year, 18 U.S. states - including the southern states of Florida and Arkansas – spent at least $20 per residential customer; 11 of those states spent at least twice as

[10] U.S. sales data from U.S. Energy Information Administration form 176 data (2012 is the most recent year for which data are available). Note that sales data for Massachusetts and Minnesota are only for sales by investor-owned utilities subject to DSM requirements and, in the case of Minnesota, exclude sales to transport customers which do not pay for or receive DSM services. Sales forecast for Enbridge Gas from EB-2012-0451/EB-2012-0433/EB-2013-0074, Exhibit I.A4.EGD.GEC.34; sales estimate for Union gas from EB-2011-0210, Exhibit C4, Tab 2, Schedule 1. DSM spending values for each state are from regulatory filings of the affected utilities in the state. DSM spending for Enbridge and Union Gas are from their respective 2012 annual reports (sometimes call "annual evaluation reports").

[11] Enbridge Gas Distribution, "2011 Draft DSM Annual Report", April 2012; and Union Gas, "Final Audited Demand Side Management 2011 Annual Report", June 29, 2012.

[12] According to NRCAN, there were 3.65 million residential gas customers in Ontario in 2011.

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much as Ontario (i.e. over $30 per residential customer).[13] Both British Columbia and Manitoba are also currently planning to spend two to three times as much on gas DSM (per m^3 of gas sales) as Ontario's gas utilities spent in 2012. Put simply, gas DSM spending in Ontario has been lagging behind not only leading jurisdictions, but even "middle of the road" jurisdictions, for a number of years.

Ramp Up Period

Though gas DSM budgets in Ontario would need to increase dramatically to get to the point where the province was acquiring all cost-effective efficiency, it would not be reasonable or prudent to expect the increase to take place immediately. Some period of ramp up would be necessary to ensure that there is sufficient time to develop new and more aggressive programs, and to increase utility and private sector delivery capability in a reasonably efficient and effective manner. The experience of the Massachusetts gas utilities may be instructive in this regard. As Figure 1 below demonstrates, Massachusetts budgeted only $38 million for gas DSM in 2009,[14] the year that a new legislative requirement to acquire all cost-effective efficiency went into effect. Spending then more than doubled the following year and continued to increase fairly linearly until 2013, at which point increases leveled off. In other words, the state ramped up to acquiring all cost-effective efficiency – with a nearly five-fold increase in budget – over the course of about 4 years.

[13] Downs, Annie et al., "2013 State Energy Efficiency Scorecard", published by the American Council for an Energy Efficient Economy, Report E13K, November 2013.
[14] Note that the 2009 budget was still more than twice per m3 of annual gas sales ($0.0060) than the current Ontario gas utility DSM budgets ($0.0024).

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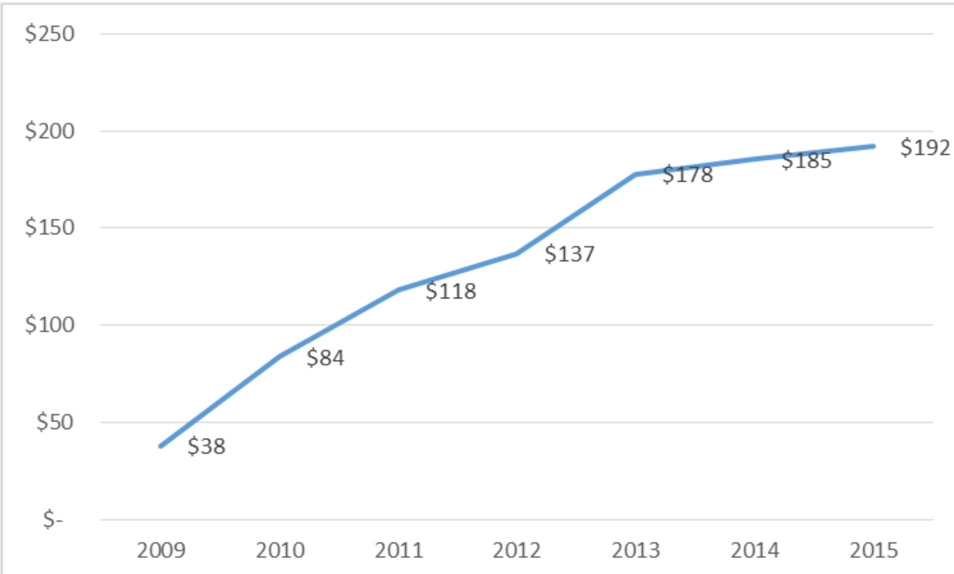
Figure 1: Massachusetts Gas DSM Budgets, 2009 to 2015 (millions of nominal dollars)[15]



Addressing Rate Impact Concerns

Historically, when the subject of potential increases in DSM spending is raised, some stakeholders have expressed concerns about resulting rate impacts. While the Energy Minister's directive to pursue all cost-effective efficiency does not include any caveats related to rate impacts, some discussion of the topic may be warranted to address common misconceptions.

To begin with, it should be emphasized that, customers' principal concern is with their total energy bill, rather than the price (rate) per unit of energy consumed; indeed, most residential and smaller business customers do not even know what their gas rate is. Any customer would prefer to have a 5% higher rate if it got a 20% reduction on consumption at the same time (resulting in a total energy bill reduction of 16%). Efficiency investments that pass a TRC cost-effectiveness screening test will, by definition, reduce the total gas bill of all customers. Thus, concerns about rate impacts associated with energy efficiency tend to be about equity (i.e. about the customers who do not participate in efficiency programs), which can be addressed by offering a broad enough portfolio of programs so that, over time, all customers have the opportunity to reap the benefits of efficiency.

[15] Budgets for 2009 through 2012 from ACEEE State Energy Efficiency Scorecards for 2010 through 2013; budgets for 2013 through 2015 from Massachusetts Department of Public Utilities order in regulatory proceedings 12-100 through 12-111, January 31, 2013.

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It is also important to recognize that there are four factors associated with DSM that could potentially affect rates:

- DSM spending, which has the effect of increasing rates;
- Avoided capital expenditures, such as on transmission and distribution systems, which have the effect of lowering rates;
- Lower demand, which has the effect of lower rates; and
- The spreading of fixed utility costs across a smaller volume of sales (commonly called utility "lost revenue") which has the effect of increasing rates.

To suggest that the last of these is a concern is tantamount to suggesting that the province would not want consumers to save energy even if savings could be acquired for free, or worse, that the province would prefer that its residents and businesses wasted more energy so that rates could go down. It is hard to imagine any such interpretation of provincial policy. Thus, the only three effects that should be of interest are the upward pressure on rates caused by DSM spending, the downward pressure on rates caused by avoided capital expenditures, and the downward pressure on rates caused by lower demand (commonly called price suppression effects).

The impact on rates of DSM spending deserves consideration. In 2012, Union Gas' and Enbridge Gas' customers were collectively forecast to consume about 26 billion m^3 of gas. Assuming that annual gas sales remain at approximately those levels, every $100 million in DSM budget would add an average of about $0.0039 to the cost of an m^3 of gas. Current residential gas costs are on the order of $0.40 to $0.45 per m^3.[16] Thus, assuming gas DSM spending was allocated approximately in proportion to sales by customer class, every $100 million in gas DSM spending in the province would result in a residential rate increase of about 1%. Thus, gas DSM spending could increase by a factor of roughly five – to $300 million between the two large gas utilities – and still add only about 3% to the average residential bill.

Moreover, that is just the cost side of the equation. The province's gas utilities have not recently estimated the value of avoided capital expenditures associated with DSM. Nor have they ever estimated the price suppression effects of lower demand resulting from efficiency programs.[17] Thus, we do not know the extent to which the impacts of DSM budgets on rates would be offset – perhaps even more than offset – by the factors that put downward pressure

[16] All costs, including commodity, cost adjustments, transportation, delivery and fixed monthly charges divided by average annual consumption of 2200 m^3 for Union Gas and 3000 m^3 for Enbridge Gas (http://www.ontarioenergyboard.ca/OEB/Consumers/Natural+Gas/Natural+Gas+Rates).
[17] See the TAF cost-effectiveness screening paper for further discussion of this topic, including estimates of the magnitude of this benefit estimated for other jurisdictions.

on rates. In addition, beyond the impact on capital expenditures, there would be substantial (TRC) economic net benefits – literally hundreds of millions of dollars – associated with each year of DSM implementation.

Since customers ultimately care more about their total gas bill than about the cost per unit of gas consumed, the best answer to any lingering concerns about rate impacts is to ensure that DSM portfolios become substantial enough and sufficiently balanced so that all customers can access programs over time.

Conclusions

Ultimately and ideally, gas savings goals and budgets to achieve those goals should be based on a bottom-up assessment of the opportunity to acquire all cost-effective gas efficiency resources. In the meanwhile, all available evidence suggests that Ontario's gas savings goals should increase substantially – to in excess of 1% of sales per year – and that the utilities' budgets should increase fairly dramatically – by at least three-fold (i.e. to at least $200 million per year) and likely to considerably higher levels given the in-efficiency of the market.

Attribution and Use

This brief has been prepared for TAF by Chris Neme, Energy Futures Group, with research support from TAF Policy Researcher, Rebecca Mallinson. Please treat this material as 'draft' as elements may evolve during the course of discussions and in the formulation of input to the formal OEB consultation. Please note that the views and ideas expressed in these briefs are presented by the Toronto Atmospheric Fund to support the discussion around developing a new gas DSM policy framework. We welcome your views about these or other issues related to natural gas conservation policy in Ontario.

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2014 OEB Gas DSM Framework Issue Paper:

Cost-Effectiveness Screening

On March 31, 2014, the Ontario Energy Minister issued a Directive that the Ontario Energy Board (OEB) establish a gas DSM framework that will enable the province's regulated gas utilities to acquire all cost-effective energy efficiency resources. One obvious issue this raises is the definition of "cost-effective". This paper reviews the principal cost-effectiveness tests used across North America, summarizes the history of gas DSM cost-effectiveness screening in Ontario, discusses short-comings of current practice and provides recommendations for the post-2014 gas DSM framework that the OEB is charged with developing.

DSM Cost-Effectiveness Tests

Dozens of Canadian provinces and U.S. states currently require regulated gas and electric utilities to pursue DSM activities. With few exceptions (e.g. low income programs in some jurisdictions), such activities are typically required to be cost-effective. Though cost-effectiveness is often examined from a number of different perspectives, almost every jurisdiction uses one of three different tests – the Program Administrator Cost (PAC) test,[1] the Total Resource Cost Test (TRC) or the Societal Cost Test (SC) – as the primary test to determine whether DSM is cost effective. The "lens" through which each of these tests assesses cost-effectiveness is different. Figure 1 provides a summary of those three perspectives.

Figure 1: Different Perspectives of the PAC, TRC and SC Tests[2]

Test	Key Question	Impacts Included	Implications
PAC	Will utility system costs decrease?	Costs and benefits experienced by the utility system.	Limited to impacts on the utility system. Indicates net impacts on utility costs and utility bills.
TRC	Will utility system plus program participants' costs decrease?	Costs and benefits experienced by the utility system, plus other costs and benefits experienced by program participants.	By including impacts beyond the utility system, this test is essentially based on a (partial) societal perspective.
SC	Will total costs to society decrease?	Costs and benefits experienced by all members of society.	Most comprehensive assessment.

[1] Alternatively called the Utility Cost Test (PACT).
[2] Adapted from Woolf, Tim et al., "The Resource Value Framework: Reforming Energy Efficiency Cost-Effectiveness Screening", prepared for the National Energy Efficiency Screening Coalition and published by the National Home Performance Council, March 28, 2014 (http://www.nhpci.org/publications/NHPC_NESP-Recommendations-Final_20140328.pdf).

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One way of thinking about these tests is that they span a continuum of impacts. The PAC is on one end in that it focuses only on costs and benefits to the utility system. Utility system impacts are included in every test. Thus, in a way the PAC is the foundation for all cost-effectiveness screening. The SC is on the other end in that it focuses on *all* costs and benefits experienced by *all* members of society (including the utility system impacts). The TRC is in between. It adds a subset of societal impacts – the additional impacts on program participants – to the utility system impacts. Figure 2 provides more detail on the types of costs and benefits included under each test.

Figure 2: Components of the Energy Efficiency Cost-Effectiveness Tests[3]

	PAC Test	TRC Test	Societal Cost Test
Energy Efficiency Program Benefits:			
Avoided Energy Costs	Yes	Yes	Yes
Avoided Capacity Costs	Yes	Yes	Yes
Avoided Transmission and Distribution Costs	Yes	Yes	Yes
Wholesale Market Price Suppression Effects	Yes	Yes	Yes
Avoided Cost of Environmental Compliance	Yes	Yes	Yes
Reduced Risk	Yes	Yes	Yes
Other Program Impacts (utility-perspective)	Yes	Yes	Yes
Other Program Impacts (participant-perspective)	---	Yes	Yes
Other Program Impacts (societal-perspective)	---	---	Yes
Energy Efficiency Program Costs:			
Program Administrator Costs	Yes	Yes	Yes
EE Measure Cost: Program Financial Incentive	Yes	Yes	Yes
EE Measure Cost: Participant Contribution	---	Yes	Yes
Other Program Impacts (participant costs)	---	Yes	Yes

Note that what should distinguish the three tests on the benefits side of the equation is the range of non-energy benefits (NEBs) included. Under the PAC, the only NEBs included are those

[3] Copied from Woolf, Tim et al. (Synapse Energy Economics), "Energy Efficiency Cost-Effectiveness Screening in the Northeast and Mid-Atlantic States: A Survey of Issues and Practices, With Recommendations for Developing Guidance to the Regional Evaluation, Measurement and Verification (EM&V) Forum", prepared for the Regional EM&V Forum, a project of the Northeast Energy Efficiency Partnerships, October 2, 2013.

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that affect the utility's bottom line. A good example would be reduced credit and collection costs. Under the TRC, NEBs experienced by program participants should also be added (since this test, by definition, is structured to assess the combined impacts on the utility system and program participants). Examples of participant NEBs include improved comfort, increased building durability, quieter equipment operation (efficient equipment is often sold as a "premium product" with other premium features), improved aesthetics, water savings, other fuel savings, reduced waste, and improved business productivity. Under the SC, additional NEBs experienced by society should also be added. The most common are environmental impacts and public health impacts.

History of Gas DSM Cost-Effectiveness Screening in Ontario

In its landmark 1993 order on gas DSM – EBO-169 – the OEB adopted a societal cost test (SC) as the principal test to determine whether a DSM program was in the public interest; the Board ruled that any program that passed the SC should be pursued, provided it didn't lead to "undue" rate impacts.[4] Several years later, in response to a settlement agreement among a number of parties, the OEB revised its position and adopted the TRC test as its primary test of cost-effectiveness. The principal difference between the SC and the TRC, as implemented in Ontario, is that the SC included estimates of the economic benefit of reducing the environmental costs of gas use (e.g. most notably to account for the reducing the adverse impact of carbon dioxide emissions and global climate change), whereas the TRC does not include consideration of environmental externalities. The TRC test has been the primary test for gas DSM in Ontario ever since.

Problems with the Application of the TRC in Ontario

As discussed above, the TRC is nominally intended to capture all costs borne and all benefits received by both the utility energy system and participating consumers. However, its application in Ontario has been far from comprehensive in addressing those impacts. Worse still, its application in Ontario has been biased in that all relevant costs have typically been included while many categories of benefits have not been. Of the eight categories of benefits that Figure 2 suggests should be captured under the TRC, only one – avoided energy costs – has typically been fully incorporated into TRC screening. The other seven categories of benefits appear to have been either totally or partially excluded from cost-effectiveness analyses to date. Each of the omissions is discussed briefly below.

[4] Ontario Energy Board, A Report on the Demand-Side Management Aspects of Gas Integrated Resource Planning for: The Consumers' Gas Company Ltd., Centra Gas Ontario Inc. and Union Gas Company, E.B.O. 169-III, Report of the Board, July 23, 1993.

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- **Avoided capacity costs**. The current Board guidelines for gas DSM, published in June 2011, clearly required the utilities to included avoided capital costs. For example, DSM can reduce the amount of investment required to provide gas storage capacity for peak periods. However, it is not clear that the Union or Enbridge currently include any avoided capital costs in their avoided costs and cost-effectiveness screening.
- **Avoided transmission and distribution (T&D) system costs**. Another element of avoided capital costs is avoided investment in the T&D system. Again, however, as became apparent in the recent GTA pipeline case, the utilities have not recently included avoided T&D capital costs in their cost-effectiveness screening of efficiency programs.[5] The magnitude of avoided gas T&D benefits will be utility and location specific. However, it is worth noting that Enbridge Gas' historic investment in efficiency likely delayed the date at which the utility estimated the pipeline project was needed. Moreover, there was substantial evidence presented in the GTA proceeding to suggest that a more substantial investment in efficiency could have continued to cost-effectively defer at least a portion of the multi-hundred million dollar project even further into the future.[6]
- **Wholesale market price suppression effects**. In a competitive market, when demand for gas or electricity goes down, the most expensive source of gas or power is no longer purchased and the market clearing price for all remaining purchases goes down. The Ontario gas utilities have never included the benefits of such wholesale market price suppression effects in their DSM cost-effectiveness screening. Though the magnitude of such reductions in prices are typically not large, the total value of even a small reduction in price can be substantial because it affects every m^3 of gas that is sold. There are two important sub-categories of these benefits. The first is a reduction in price – and therefore cost – of direct use of gas by consumers. The second is a reduction in price of gas used for electric generation, which results in a reduction in electricity prices and therefore a reduction in electricity costs borne by consumers. A recent study for the New England states found that the combination of these two price suppression effects (most of the benefit was from reduced electricity prices) would add an average of nearly $113 to the net present value of an MMBtu of gas heating savings over a 15 year measure life.[7] If the same

[5] The evidence of Paul L. Chernick in EB-2012-0451/0433/0074 found that, if the data provided were typical, "the avoided cost of routine load-related reinforcements would be…roughly $0.23/m^3$ on an annual basis for average retail load." (p. 21)
[6] See testimony of Chris Neme and Paul Chernick on behalf of the Green Energy Coalition, as well as testimony of Ian Jarvis on behalf of Environmental Defense in EB-2012-0451.
[7] Hornby, Rick et al., "Avoided Energy Supply Costs in New England: 2013 Report", prepared for the Avoided-Energy-Supply-Component (AESC) Study Group, July 12, 2013, pp. 1-19 and 1-20. Levelized annual New England benefit values converted to a 15 year NPV using the same real discount rate used in the study.

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values were applicable to Ontario, the net present value per m^3 of heating savings would be approximately $4.11.[8] That is nearly double the 15-year NPV of avoided energy for space heating measures that was used in 2013 by Enbridge.[9] Put another way, if the New England price suppression effects were applicable to Ontario, they would, by themselves, effectively triple Enbridge's current estimated value of gas savings. To be sure, the value of price suppression effects can vary considerably from region to region; there are differences even among the six New England states, and Ontario's gas import capability is not as constrained as New England's. However, if nothing else, this suggests that it is imperative that an assessment of price suppression effects be independently estimated for Ontario's gas utilities and that the benefits should be included in cost-effectiveness screening.

- **Avoided cost of environmental compliance**. Utilities should include in their avoided costs both the costs of complying with environmental regulations that have become law and the potential cost – possibly probability weighted – of the cost of complying with new environmental regulations that have a reasonable probability of being adopted in the future. To not account for at least the probability of such costs is to consciously understate the benefits of efficiency. In context of Ontario's gas utilities operations, for example, there should be some value attached to the reduction in carbon emissions because the province, through its 2007 Climate Change Action Plan, has set an objective of reducing greenhouse-gas emissions 15% from 1990 to 2020 and 80% by 2050 and will fall short of those targets absent new regulations or unexpected changes in the market. Moreover, "emissions due to natural gas consumption remain a significant barrier to future progress."[10] However, the Ontario utilities do not currently account for the likelihood of future carbon emission constraints in the estimates of avoided costs.
- **Reduced risk**. One benefit of efficiency is that it reduces consumers' exposure to the risk of future fuel price volatility – a phenomenon that the recent unexpected spike in winter gas prices has clearly demonstrated. To address this and related risks, the Vermont regulator (the Public Service Board) has required that all efficiency measure costs be reduced by 10% (to reflect the comparative certainty of those costs) when performing cost-effectiveness screening. An alternative would be to provide an "adder" to avoided energy costs (to reflect their relatively lower certainty). Ontario's gas utilities have never considered this benefit in their TRC screening.

[8] Conversion based on assumed 35,000 BTU/m3 and an average 2013 exchange rate of $0.96 USD to $1.00 CDN.
[9] Enbridge Gas Distribution, 2013 Demand Side Management Draft Evaluation Report, May 7, 2014, p. 119.
[10] Environmental Commissioner of Ontario, "A Question of Commitment: Review of the Ontario Government's Climate Change Action Plan Results", Annual Greenhouse Gas Progress Report 2012, December 2012. (p. 13)

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- **Utility NEBs**. The Ontario gas utilities have never included the value of reduced credit and collection costs in their cost-effectiveness screening. It should be noted that the Board's 2011 DSM guidelines did lower the cost-effectiveness threshold required for low income programs to a benefit-cost ratio of 0.7, in part to capture the effects of such benefits. However, low income customers are not the only customers that impose credit and collection costs on the system. An analysis of the magnitude of such costs should ideally be conducted to assess both their total value and the portion of that value that is associated with non-low income program participants. The non-low income portion of the value should then be added to other avoided costs. Alternatively, Ontario could develop assumptions regarding such impacts by extrapolating from results of studies in other jurisdictions.
- **Participant NEBs**. Historically, the Ontario gas utilities have included in screening only what are sometimes called "resource NEBs" – i.e. the values of electricity savings and water savings. There is extensive literature on participant NEBs which suggests that the value of numerous other "non-resource NEBs" can be substantial. Indeed, many leading efficiency programs across the continent often actively sell customers on efficiency investments by aggressively promoting non-energy benefits such as improved comfort and improved business productivity. An increasing number of jurisdictions have begun to address this issue by either directly quantifying such NEBs or by adopting across-the-board participant NEBs "adders" to avoided costs. For example, the Massachusetts gas utilities now routinely include non-resource benefits such as improved comfort and improved health and safety in their cost-effectiveness screening. Results from 2013 suggest that the value of those non-resource benefits for their home retrofit program had an NPV of nearly \$3 per m^3 saved over an average program measure life of 18 years.[11] Those values were derived after extensive study of the value of different kinds of participant NEBs using the Massachusetts utilities' evaluation budgets. By comparison, Enbridge's avoided energy costs for space heating savings were \$2.55 per m^3 saved (for the same 18-year measure life).[12] In other words, the Massachusetts NEBs for this program were greater than Enbridge's total avoided energy costs. That comparison is consistent with a recent study that found that participant NEBs for home weatherization programs averaged between 89% and 140% of energy or bill savings.[13] In Vermont, the state regulators have taken a simpler and more conservative approach. They now require that 15% be added to the calculated energy benefits of

[11] Massachusetts' utilities 2013 4th quarter reports.
[12] Enbridge Gas Distribution, 2013 Demand Side Management Draft Evaluation Report, May 7, 2014, p. 119.
[13] Skumatz, Lisa, "Non-Energy Benefits/Non-Energy Impacts (NEBs/NEIs) and their Role & Values in Cost-Effectiveness Tests: State of Maryland", Prepared for the Natural Resources Defense Council, March 31, 2014.

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efficiency,[14] with an additional 15% adder for low income programs. The regulators acknowledge that these are default values are intentionally "conservative" and will be revisited in the future.[15]

In short, the current application of the TRC test in Ontario produces results that are skewed against efficiency because it includes all of the costs that should be captured in the "utility system plus participant" perspective on cost-effectiveness that the test is purported to provide, but only a portion – and arguably only a minority – of the benefits that should be captured. Ontario is not unique in this regard. Many other jurisdictions that use the TRC have also not fully captured all of the benefits of efficiency. However, as some of the examples provide above demonstrate, that has changed in a number of jurisdictions. Similar changes are necessary in Ontario regardless of government policy.

Recommendations for the Future

A group of DSM experts from across North American recently developed and published a new set of guidelines – embodied by what it calls the Resource Value Framework (RVF) – for assessing the cost-effectiveness of efficiency programs.[16] The framework does not promote the universal adoption of any particular screening test. Rather, it articulates a number of key principles that should guide both the selection of a primary cost-effectiveness screening test and the use or application of the selected test. Ontario would do well to follow this guidance.

Selection of Cost-Effectiveness Test

One of the key principles of the framework is that the selection of the primary cost-effectiveness test should be based on the policies of the jurisdiction. As noted above, there is a continuum of options, starting from the least comprehensive utility system perspective (the perspective addressed by the PAC) and ending at the most comprehensive societal perspective in which all costs and benefits to all members of society are assessed. There are a potentially unlimited number of points in between. Put simply, every test must include utility system benefits and costs; the determination of which additional types of benefits and costs to include

[14] This adder is over and above the value of other energy/fuel savings, water savings and customer operations and maintenance savings, which were already being captured in Vermont screening.
[15] State of Vermont Public Service Board, "Order Re Cost-Effectiveness Screening of heating and Process-Fuel Efficiency Measures and Modifications to State Cost-Effectiveness Screening Tool", Order entered 2/7/2012, pp. 26-27.
[16] Woolf, Tim et al., "The Resource Value Framework: Reforming Energy Efficiency Cost-Effectiveness Screening", prepared for the National Energy Efficiency Screening Coalition and published by the National Home Performance Council, March 28, 2014 (http://www.nhpci.org/publications/NHPC_NESP-Recommendations-Final_20140328.pdf).

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– participant impacts, additional low income impacts, health impacts, climate change impacts, other environmental impacts, etc. – should be a function of government policies relative to those impacts. Since the Ontario government has adopted policies that indicate concern over all of these impacts, it would seem appropriate to adopt the full societal test.

At a minimum, the Board should require the addition of carbon dioxide emission externalities to cost-effectiveness screening. As discussed above, the provincial government has not only expressed concern about climate change, it has established clear targets for carbon emission reductions and the province's Environmental Commissioner has asserted that those targets will not be met without greater effort, including greater effort in the gas sector. Moreover, the Ontario Energy Minister clearly identified the benefit of reduced emissions of environmental pollutants – "including greenhouse gas emissions" – as part of the rationale for the directive to put conservation first in the province's long-term energy plan.

Note that the development of a carbon emissions externality factor was quite challenging back in the early to mid-1990s. Ontario was truly on the cutting edge at the time. Nevertheless, a factor was developed and used. Nearly twenty years later, numerous jurisdictions now routinely include a carbon emissions externality value in integrated resource planning and/or cost-effectiveness screening of energy efficiency. A subset of those recently analyzed by Synapse Energy Economics is shown in Figure 3 below. Thus, the OEB would have numerous reference points for consideration in developing a new value for Ontario screening.[17]

[17] Including carbon emission costs is appropriate for comparing gas supply to conservation (which has few if any negative externalities) but caution should be exercised when comparing supply options, in which case all significant externalities should be included to avoid skewed selections. For example, when comparing electricity generation choices uninsured nuclear risk is a major externality that can and should be monetized.

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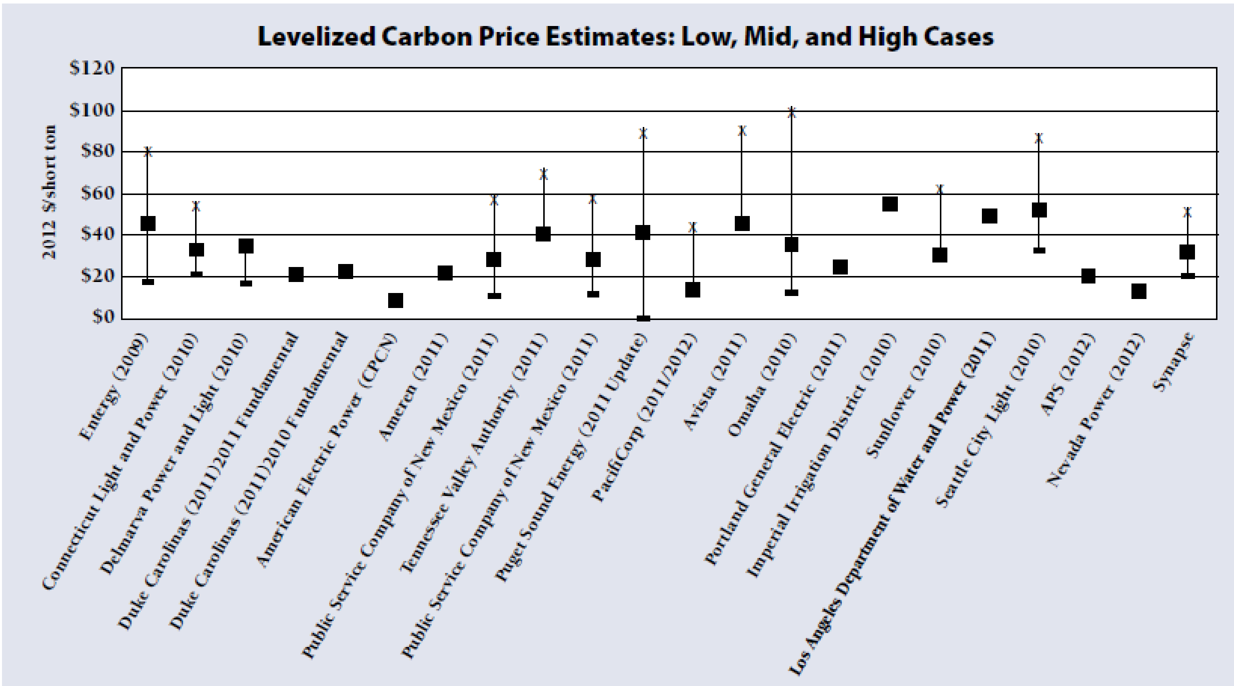
Figure 3: Levelized Carbon Emission Prices from Utility IRPs[18]



Application of Cost-Effectiveness Test

A second key principle of the RVF is that costs and benefits should be treated symmetrically. That is, whatever screening perspective is taken – whether the limited utility system perspective or the expansive societal perspective or something in between – screening must include the full range of costs and benefits associated with the perspective.

To use a concrete example, it is inappropriate to include participants' costs in the TRC or SC (remembering that the TRC is supposed to address the combination of utility system and program participant impacts, and the SC is supposed to address all impacts on society) if one also does not include all of participants' benefits. That is not to say that untold millions of dollars must be spent to quantify every conceivable participant NEB. However, it would equally inappropriate to assume – implicitly or explicitly – that NEBs have no value. There needs to be practical limitations imposed. At a minimum, screening should include default participant non-resource NEB adders. If for any reason that is deemed to not be appropriate, then it would be better – more balanced – to exclude the participant perspective from the analysis altogether.

[18] Figure copied from Woolf, Tim et al. (Synapse Energy Economics), "Energy Efficiency Cost-Effectiveness Screening: How to Properly Account for 'Other Program Impacts' and Environmental Compliance Costs", published by the Regulatory Assistance Project, November 2012.

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That would be analogous to moving from the TRC to the PAC. It would also be analogous to moving from the SC to the PAC plus environmental externalities.

Attribution and Use

This brief has been prepared for TAF by Chris Neme, Energy Futures Group, with research support from TAF Policy Researcher, Rebecca Mallinson. Please treat this material as 'draft' as elements may evolve during the course of discussions and in the formulation of input to the formal OEB consultation. Please note that the views and ideas expressed in these briefs are presented by the Toronto Atmospheric Fund to support the discussion around developing a new gas DSM policy framework. We welcome your views about these or other issues related to natural gas conservation policy in Ontario.

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2014 OEB Gas DSM Framework Issue Paper:

Performance Measurement

Current Ontario Framework

In June 2011, the Ontario Energy Board (OEB) issued a new set of demand-side management (DSM) guidelines for the province's two gas utilities. Among the key issues those guidelines addressed was the assessment of the actual performance of the utilities DSM programs, particularly in comparison to performance goals or metrics that would be established in the utilities' DSM plans. The same OEB guidelines allow the utilities to earn substantial financial incentives for their shareholders for meeting or exceeding their goals. Subsequent to the OEB's publication of its DSM guidelines, the utilities filed their plans. As part of those plans, the utilities included new proposals that expanded on the OEB's guidelines regarding performance measurement. Those proposals were ultimately approved by the OEB. The result is the gas DSM performance measurement framework in place in Ontario today. What follows is a summary of key elements of the current framework:

- **Evaluation plans**. The utilities are required to file plans for how they will evaluation the effectiveness of their DSM programs as part of their three-year DSM plans.
- **Evaluation budgets**. The utilities are required to identify the portion of their DSM budgets that will be spend on evaluation. For the approved 2012-2014 plans, the utilities' proposed evaluation budgets were approximately 3% of their total DSM budgets.[1]
- **Prescriptive savings assumptions**. Each year the utilities jointly file savings and other assumptions (e.g. measure life and incremental cost) that they expect to use when estimating the impacts of prescriptive efficiency measures. Those assumptions are based on both data collected in Ontario and on research and evaluation conducted in other jurisdictions. Prescriptive efficiency measures are typically measures for which *average* savings across an entire population of program participants can be estimated with some confidence and for which site-specific estimates of savings would be prohibitively expensive (e.g. for measures which are rebated and/or installed in substantial quantities in homes or smaller businesses). Though the OEB's 2011 guidelines make clear that the utilities must use the best available information on savings at the time that their annual savings claims are made (typically in the Spring for the previous year – see below), the filed assumptions

[1] Enbridge's ranged from 2.4% in 2012 to 2.8% in 2014 (EB-2012-0394, Exhibit B, Tab 1, Schedule 5). That was for direct costs only; it did not include costs for tracking and reporting, management of research and costs associated with stakeholder engagement. Union's was 3.2% (EB-2011-0327, Exhibit A).

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serve as default assumptions in the event that no new and better information has become available.

- **Free ridership and spillover**. The savings that an efficiency measure produces in the home or business in which it is installed is commonly called its "gross savings". In contrast, "net savings" refers to the portion of gross savings that are attributable to a utility's efficiency program. It can adjust for the portion of savings that would have occurred anyway (e.g. because the customer would have installed the efficiency measure even without the utility rebate). Such effects are call free ridership. It can also adjust for the impacts a utility program has on the purchase and installation of efficiency measures that never get recorded by the utility (e.g. a customer is influenced by interaction with the utility to buy an efficiency measure but never claims a rebate). Such effects are called spillover effects.[2] The OEB requires that utilities adjust all of their savings to account for free rider effects. Though not required, it allows utilities to claim spillover effects provided that they are "supported by comprehensive and convincing empirical evidence, which clearly quantify the spillover effects that a specific program has had…"[3] To this point, the utilities have not made any such spillover claims. The conversion to net savings from gross savings is commonly called a "net-to-gross" (NTG) adjustment.
- **Custom Project Savings Verification (CPSV).** Every year the utilities hire engineering firms to critically review their estimates of savings for custom commercial and industrial efficiency projects. Custom projects often account for 80% of more of each utilities' total savings estimates. This process includes both a desk review of savings calculations and on-site visits to the facilities to verify that the measures were installed, take measurements of key efficiency or other operational parameters as appropriate, and discuss the project with the business. Only a sample of projects is reviewed. The CPSV firm's proposed changes to savings estimates for the sampled projects are then extrapolated – using what the evaluation industry calls "realization rates" – to the entire population of custom projects. This process has evolved over the years to the point where there is now in place a detailed sampling protocol (developed by an expert contractor hired by the TEC – see below) designed to provide 90% confidence that the extrapolation of savings adjustments to the

[2] Spillover can further be subdivided into three categories: (1) inside participant spillover which accounts for additional measures that a program participant installed at the same site as measures the utility rebated (or tracked and claimed as direct participant savings for other reasons); (2) outside participant spillover which accounts for saving that a program participant installs at a different site; and (3) non-participant spillover, which accounts for measures installed by customers who never directly participated in the utility's DSM programs in a way in which the utility would immediately know that savings had occurred.
[3] Ontario Energy Board, "Demand Side Management Guidelines for Natural Gas Utilities", EB-2008-0346, June 30, 2011.

entire population of custom projects produces a total custom project savings estimate that is within 10% of what would have been found had every one of the (typically) hundreds of custom projects been separately reviewed.

- **Annual Reports**. The utilities are required to produce reports after the conclusion of each program year which document the savings achieved, as well as performance relative to other key metrics – particularly those metrics established for the purpose of (potentially) earning shareholder incentives. The results from the CPSV reports are incorporated into the annual report.
- **Annual Audit**. Each year an auditor is hired (separately for each utility) through the Audit Committee process (see below) to independently assess the reasonableness of the Company's claims regarding savings and other performance metrics addressed in its Annual Report. The auditor's report – included proposed adjustments to the utility's savings claim, its performance relative to other metrics of interest, its eligibility for shareholder incentives, its lost revenue adjustment and other factors – is required to be filed with the OEB by the end of June (i.e. within 6 months of the end of the year on which it is reporting).
- **Audit Committee (AC)**. The ACs' – which have been comprised of a utility representative and three elected stakeholder representatives – were originally created in 2000 to give stakeholders a voice in the hiring and input on the work of the independent auditors. However, their roles had gradually evolved to include providing some input on evaluation priorities, draft prescriptive measure savings characterizations and related items. With the filing of the utilities' 2012-2014 DSM plans, that portion of their role was shifted to the TEC (see below). In addition, their approach to decision-making – particularly in the selection of the annual auditor – was changed. In the past, though there was often consensus on the selection of the auditor, the utilities always had the final say. Under the new rules, the utilities and elected stakeholder reps continue to try to reach consensus on both a bidders list and on the ultimate selection of the auditor from among the firms who bid. However, in the event that consensus is not possible, the utilities get the final say on the bidders list – provided it has at least nine qualified firms on it – and the elected stakeholder reps have the final say on the selection of the auditor. This process is also communicated to all bidders, so that they realize that they are not just answering to the utility (to ensure that their work is truly independent).
- **Technical Evaluation Committee (TEC).** The TEC is to be comprised of a representative from each utility, three elected stakeholder representatives and two independent members who would be appointed by other five utility/stakeholder members. It is charged with developing gas DSM evaluation priorities for the province; developing scopes of work for new, high-priority province-wide evaluation projects; and hiring and overseeing evaluation

contractors in the performance of that work. The TEC is designed to operate by consensus to the greatest extent possible, including in the selection of its independent members. Over the two years it has been in effect, the TEC has completed work on a sampling protocol for the CPSV process; reviewed and approved for submittal to the OEB a number of new measure savings (and other) assumptions as well as some changes to existing assumptions; and launched two major new evaluation projects – one to critically review all existing prescriptive assumptions and develop the provinces first, comprehensive, on-line Technical Reference Manual of such assumptions and another to assess free ridership and spillover for custom commercial and industrial projects. Both of the latter two evaluation projects are currently underway and expected to be completed in late 2014 or early 2015.

Comparison of Current Ontario Framework to Industry Best Practices

What follows is a brief assessment of how the current Ontario framework for performance measurement compares to best practices across North America. We focus particularly on the following items:

- Independence of evaluation
- Requirements for impact evaluation
- Net-to-gross (NTG) adjustments

Independence of Evaluation

It is always important that any evaluation of the impacts of DSM be independent of the entity charged with delivering energy savings and other forms of progress in markets for efficiency. It is particularly important when the entity charged with delivering results – the gas utilities in Ontario – has the ability to earn substantial financial incentives for meeting or exceeding goals – as is the case in Ontario. In the 1990s, it was standard practice to consider an evaluation to be "independent" if it was conducted by an independent third party, even if that party was chosen, managed and paid by the utility whose performance it was evaluating. However, that has changed over the past decade. Numerous jurisdictions now vest responsibility for evaluation - including setting evaluation priorities, establishing scopes of work for evaluations, selecting evaluation contractors and overseeing their work – with parties other than the utility or non-utility parties charged with delivering efficiency programs (the utility or non-utility program administrators have input into decisions, but someone else has the final say).

A variety of models for independent management of DSM evaluation are being used, with the decisions on details of the approach a function of the strength of existing institutions, capacity

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constraints, historic relationships and other local factors. Some jurisdictions, such as Vermont, vest the responsibility with a government agency (e.g. the Vermont Department of Public Service). Others vest it with regulatory staff. For example, staff of the Illinois Commerce Commission have veto power over the hiring of the utilities' evaluation contractors and exercise considerable influence over the design of evaluation studies. In yet another approach, the New Jersey Board of Public Utilities chooses to contract with the Rutgers University Center for Energy, Economic and Environmental Policy to manage the state's DSM evaluation work. Another model is used in the southern New England states of Massachusetts and Connecticut. In those states, the utilities have ceded responsibility for evaluation to councils comprised of state government agencies, consumer groups and environmental advocates. Typically, those councils have their own expert consultants which they hire with funds provided by the utilities. The consultants support council stakeholders in negotiating the utilities' DSM performance goals, help the council engage the utilities on ways to improve their programs and become the staff that oversee the DSM evaluation work.

To be sure, over the past 14 years the OEB has made significant strides in making gas DSM evaluation more independent as well. This began in 2000 with the requirement of annual independent audits of utility savings claims and the creation of audit committees to oversee those audits. However, until recently, the auditors were still ultimately under the control of the utilities. The utilities had the final say in who to hire. The also typically had much more interaction with the auditor, with audit committees being briefed much less frequently regarding key audit questions, likely leading to greater utility influence on the audit outcomes. In addition, the utilities retained complete control over decisions on how to spend evaluation budgets, the crafting of scopes of work for evaluation studies, the selection of evaluation contractors and the over-sight of their work. The only check on that control was having the auditors review the resulting reports. A significant additional improvement was made a couple of years ago when the TEC was created – giving stakeholders an equal voice in establishing evaluation priorities, hiring of evaluation contractors and overseeing the work of those contractors – and the changing of the rules for hiring of auditors – giving stakeholders final say in who to hire (keeping in mind that the utilities had final say in developing the bidders' list) in the event a hiring consensus decision (with the utility) was not possible. In addition, the audit committee members are also now invited to participate in all substantive discussions with the auditor.

Despite this significant progress, one substantial conflict with the concept of evaluation independence remains. Specifically, the utilities still have complete control over the hiring and oversight of the CPSV firms charged with evaluating the reasonableness of the companies'

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custom commercial and industrial efficiency projects – projects that typically produce the lion's share (often 80% or more) of their savings. To be sure, stakeholders – through the TEC – have input on the scope of work for the CPSV firms. As recently as this current year (e.g. the 2013 Enbridge audit), they also have received increased (relative to past years) ability to review and provide feedback on both the draft and final work products of the CPSV firms (in the previous year, stakeholder members of the AC were only able to review the final CPSV reports). The CPSV firms' work is also reviewed and critiqued by the annual auditor. However, the CPSV firms still know that they are hired and managed exclusively by the utilities. Their budgets are also set by the utilities.

Thus, one important process modification the OEB should make in its next gas DSM guidelines is to make the hiring and oversight of the work of the CPSV firms independent of the utilities. Perhaps the most logical way to do that within the existing Ontario evaluation structure – which appears to be functioning reasonably well otherwise – would be to have the Audit Committees hire the auditor earlier (i.e. late summer or early fall of the year whose results they will audit) and have the auditor hire and oversee the work of the CPSV firms. This would not require a significant increase in the work load of the auditor because they already do intensive reviews of the CPSV firms' work. Indeed, it might even reduce some aspects of the auditors' work load because they could shape the CPSV work at the outset, rather than trying to fix problems them find after the work has been completed. This approach should address the concerns about the thoroughness and independence of the custom commercial and industrial savings estimates that were recently raised before the OEB in proceedings regarding both Union's and Enbridge's 2012 shareholder incentive claims.

Requirements for impact evaluation

In most jurisdictions where there is substantial investment in DSM, there is an expectation – and often even a regulatory requirement – that all "resource acquisition" programs of any appreciable size will be subjected to a regular cycle of impact evaluations (typically ranging from annually to every three years, depending on the size of the program, expected variability of savings, cost of evaluation and other factors). Such evaluations are commonly used to update deemed savings values and/or to directly adjust utility estimates of program savings (as well as to inform future program design).

Historically, there has been less impact evaluation of the Ontario gas utilities' DSM programs than of comparable programs in other leading jurisdictions. Most of the impact evaluation that has taken place in Ontario has taken the form of either verification studies to determine whether measures were actually installed and stayed installed or, more recently, independent

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engineering assessments of the reasonableness of the companies' custom C&I project savings estimates. There has been very little direct measurement of actual savings – either for the purposes of adjusting deemed savings values for individual measures, for developing revised baseline assumptions for key technologies or for adjusting program-level savings estimates. To be sure, there have been exceptions. Enbridge's measurement of pre- and post-installation gas consumption to estimate the impacts of retrofitting low flow showerheads is a good example. However, such work has been the exception rather than the rule. There are some signs of improvement in recent years. For example, following a recommendation from a recent Enbridge auditor,[4] the recent CPSV terms of reference require on-site measurements whenever possible to augment "desk reviews" of custom project savings calculations. However, much needs to be done to "catch up" to the level of measurement that is performed in other jurisdictions.

Part of the problem is likely to be a function of inadequate budgeting for evaluation. A rough rule of thumb is that evaluation should consume between 3% and 6% of DSM budgets.[5] As noted above, in their 2012-2014 DSM plan, Enbridge Gas set aside 2.4% to 2.8% of their total budget for evaluation. Union Gas set aside 3.2%. Those are respectable budget levels – at least at the lower end of the range that would be ideal. However, it is important to note that evaluation spending in prior years was substantially lower. For example, in 2011, Union Gas spent only about $470,000 (or about 1.7%) of the approximately $28 million that it spend on DSM.[6]

All of this suggests that the Board should consider the following when developing the next set of guidelines for gas DSM in the province:

- Require that all programs undergo some form of impact evaluation at least once every three years;
- Require that, in addition to key verification activities, such impact evaluations include some form of measurement – whether whole facility billing analysis, end use metering, calibrated building simulation modeling, and/or other accepted methods;

[4] Energy & Resource Solutions, "Independent Audit of Enbridge Gas Distribution 2012 DSM Program Results", Final Report, June 26, 2013 and Energy & Resource Solutions, "Independent Audit of Enbridge Gas Distribution 2011 DSM Program Results", Final Report, June 27, 2012.
[5] State and Local Energy Efficiency Action Network, "Energy Efficiency Program Impact Evaluation Guide", prepared by Steven R. Schiller, Schiller Consulting, Inc., December 2012, www.seeaction.energy.gov
[6] Union Gas, "Final Audited Demand Side Management 2011 Annual Report", June 29, 2012.

- Require that impact assessment of the very large custom C&I programs continue to be conducted through the CPSV process, but with increased emphasis on on-site measurement;
- Require a minimum of 3% of DSM budgets continue to be set aside for evaluation, with higher amounts to be encouraged if required in the short term to address key data uncertainties;
- Push back the deadline by which annual audit reports must be filed from the end of June to at least the end of July in order to facilitate more extensive field work by CPSV firms.

Net to Gross Adjustments

As noted above, the current OEB guidelines require that the utilities' gross savings be adjusted for free ridership; adjustments for spillover are permitted – with sufficient evidence – but not required. There are at least a couple of concerns with how this policy has been implemented to date.

First, there has been almost no direct evaluation of either free ridership or spillover for Ontario's gas DSM programs. As noted above, the TEC is currently managing a new study of such effects for Union's and Enbridge's custom commercial and industrial (C&I) programs. However, that study is just getting underway, so results are not likely to be available until late 2014 – more than six years after the only other study of free ridership and spillover for custom C&I programs.[7] Moreover, neither utility has sponsored and made public any other study of free ridership and/or spillover effects for any other market since then. Thus, most of the free ridership estimates currently being used are based on either professional judgment or studies from other jurisdictions, and most have not been changed in years. Put simply, there has been a significant under-investment in net-to-gross evaluation in the province.

Second, the approach to net-to-gross adjustments embodied in the OEB's current gas DSM guidelines leads to an inherently conservative estimate of DSM savings and cost-effectiveness. To be sure, this approach protects against utilities "chasing free riders" or attempting to claim inflated levels of spillover to meet goals, which could be a natural tendency absent such a protection, especially with the wide latitude given to the utilities to adjust the design of their programs as they see fit to meet goals[8] and the significant shareholder incentives at stake if those goals are met and/or exceeded. Such protection is important. However, the Board can

[7] Summit Blue Consulting, "Custom Projects Attribution Study", submitted to Union Gas and Enbridge Gas, October 31, 2008.

[8] This kind of flexibility is generally a "good thing" in that it allows utilities to adapt in real time to feedback from the market about which strategies to promote efficiency are working and which are not.

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retain that protection while producing more balanced estimates of savings by making clear that estimates of spillover that are based on independent studies of the Ontario utilities' programs, using industry accepted methods, will be accepted. The Board can also require that spillover be assessed as part of evaluation activities whenever the incremental accuracy in net savings is commensurate with the incremental cost of the spillover assessment.

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2014 OEB Gas DSM Framework Issue Paper:

Performance Incentives

Current Ontario Framework

In June 2011, the Ontario Energy Board (OEB) issued a new set of demand-side management (DSM) guidelines for the province's two gas utilities. Among the key issues those guidelines addressed was incentive payments "to encourage [the utilities] to aggressively pursue DSM savings and recognize exemplary performance" of the utilities' DSM programs.

The 2011 guidelines established a $9.5 million cap on the incentive for budgets of $28.1 million and $27.4 million for Enbridge and Union respectively, with the cap scaling in proportion to the budget. The incentive caps are thus set in the range of 34% to 35% of the budgets. The incentive caps are subdivided in proportion to the percentage of the budget for each of three program clusters (resource acquisition, low-income, and market transformation).

For resource acquisition and low-income programs, the OEB decided that the incentive should be based on the following metrics:

- Cubic meters (m^3) of cumulative natural gas saved;
- $ spent per m^3 of cumulative natural gas saved, as a measure of prevention of lost opportunities; and
- The number of participants that receive at least one deep measure, where "deep measures" are to be determined by a consensus process and "could include increase in insulation in more than half of the walls, basement walls, or the attic of the home."

For market-transformation programs, the OEB expressed a preference for the first two metrics above and "other outcome based metrics."

The OEB specified that the incentive structure for each metric would start at a level that the OEB describes as the 50% level (although it need not be 50% of the target level[9]), rising linearly to 40% of the cap at the target, and 100% of the cap at the 150% level. See Table 1: Savings Achieved and Shareholder Incentive Earned for a visual representation.

[9] For example, the OEB's 2011 DSM Guidelines for Natural Gas Utilities explains that "50%", "100%" and "150%" targets could be set at 40 units, 60 units and 70 units, respectively (p. 32). To clarify the concepts, subsequent settlements have seen the "50%/100%/150%" terminology replaced by the terms "lower band," "target", and "upper band" (for Union) and "lower," "middle," and "high" targets (for Enbridge).

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Table 1: Savings Achieved and Shareholder Incentive Earned

Savings Level	% of Shareholder Incentive Cap Earned
"150% level" (OEB) "High target" (Enbridge) "Upper band" (Union)	100%
"100% level" (OEB) "Middle target" (Enbridge) "Target" (Union)	40%
"50% level"(OEB) "Lower target" (Enbridge) "Lower band" (Union)	0%

Current Ontario Incentive Structures

Settlements among the stakeholders have refined the OEB's approach in several ways:

- The $ spent per m3 of gas saved incentive concept has not been used. This is wise. A low $/m3 may indicate good program management, or it may be a result of cream-skimming. A high program cost per m3 can indicate that the program is achieving deeper savings, or it can indicate poor management of contractors, over-paying for services, and paying higher incentives that necessary, all of which would use up budget that could better be used for additional installations. The OEB indicated that part of the motivation for this kind of metric would be to provide an inducement for utilities to maximize the effectiveness of their spending. However, that objective should already be sufficiently encouraged by combining sufficiently aggressive performance metrics, rigorous evaluation and budget constraints.
- Union split the resource acquisition category between industrial customers with opt-out options and other customers, and split the deep-savings metric for the latter between residential and non-residential customers.
- For the low-income programs, incentives are split between single- and multi-family m3, and Enbridge added a metric for the percentage of customers on the Low Income Building Performance Management (LIBPM) who enroll in the DSM program.

The Rationale for Incentives

Utilities often act as though their primary interest is in growing their rate base. Load growth requires installation of more mains, which increases rate base and total earnings, but also requires that the utility raise more capital, spreading those earnings over more shares. Increasing rate base will not benefit shareholders if the OEB sets the return on equity at a level

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that is just high enough to allow the utilities to attract capital. In that situation, increased investment would increase earnings but require the utility to raise more capital, and the existing shareholders would be no better off once the higher earnings are spread over both the existing and new shareholders. In the presence of an effective LRM, DSM would not harm LDC earnings per share.

If the OEB allows a return on equity higher than the actual cost of equity, shareholders would benefit from increasing rate base. For example, if new equity could be attracted with a return of about 8%, but the OEB allowed a 10% ROE[10], the DSM incentive would need to provide utility shareholders with an offsetting benefit equivalent to about 2% of the equity, times the avoided capital costs of LDC investments attributable to the DSM.

Since the Ontario LDCs have never acknowledged that any distribution capital projects are avoidable through DSM, let alone estimated the avoided investment, it is difficult to determine what incentive would be required to overcome the disincentive of the hypothetical lost-ROE windfall.

Other factors may also encourage the utilities to favor throughput over DSM. Management may benefit both financially and in less tangible ways from higher sales and investments. In addition, both Enbridge Gas Distribution and Union are affiliates of pipeline companies, which may be able to increase earnings by increasing pipeline throughput to their affiliated LDCs.

If, for any reason, the DSM incentives that are adequate in many leading jurisdictions are not sufficient to motivate effective DSM planning and implementation in Ontario, the OEB should consider alternatives, including moving responsibility for DSM to an independent entity, similar to those in Vermont, Nova Scotia, Oregon, and a handful of other North American jurisdictions.

Shareholder Incentive Levels

As a basic principal, utility shareholder incentives should be large enough to engage senior management, to attract good staff to work on DSM and to make (along with lost revenue adjustments and other policies) the pursuit of all cost-effective efficiency at least as profitable for the utility as not promoting efficiency would be. Of course, the incentives should also be no larger than necessary to accomplish those objectives. Needless to say, it is not always simple to determine exactly where that fine line is.

[10] Pollution Probe posited such a situation in EB-2002-0484, Pollution Probe Final Argument, p. 3.

With those objectives in mind, it may be useful to benchmark the current Ontario gas incentives against those in place in other jurisdictions. One commonly used benchmark is the size of the incentives in comparison to DSM budgets. As Table 2 shows, the incentives offered to the Ontario gas utilities are at the high end of continent-wide practice for gas and electric DSM incentives using that benchmark.

Table 2: Energy-Efficiency Incentive Caps as Percent of Spending

Jurisdiction	Covered Program Administrators	Fuels	Incentive Cap as % of Budget
Arizona	APS		20%
Arkansas	All	Electric &Gas	7%
California	PG&E	Electric &Gas	10.1%
Colorado	Xcel, Black Hills	Electric	20%
Connecticut	All IOUs	Electric &Gas	8%
District of Columbia	DC Efficiency Utility	Electric &Gas	4.2%
Georgia			No cap
Kentucky	Duke, Kentucky Power		10%
Massachusetts	All IOUs	Electric &Gas	5.5%
Michigan	All IOUs	Electric &Gas	15%
Minnesota			30%
Nevada			5%
New Hampshire			12%
New York	All LDCs	Gas	2.3%
North Carolina	Duke		No cap
Ohio			15%
Oklahoma			15%
Rhode Island	National Grid	Electric	4.4%
Texas	All IOUs	Electric	20%
Vermont	Efficiency VT	Electric &Gas	4.1%

However, that benchmark is only relevant if the DSM budgets of the comparison jurisdictions are also comparable to those in Ontario. Put another way, a large percent of a small budget may be less effective in attracting management attention and offsetting lost earnings from supply-side investments than a smaller percent of a much larger budget. As demonstrated in TAF's paper on DSM budgets and goals, Ontario gas DSM spending in recent years has been much lower than spending in leading jurisdictions. Thus, as shown in Table 3, though the Ontario utilities' maximum shareholder incentive is more than twice that of the Michigan utilities and nearly ten times that of the Massachusetts' utilities when expressed as a percent of DSM budget, it is actually fairly similar to both jurisdictions when normalized to each

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jurisdiction's annual gas sales.[11] This suggests that shareholder incentives could be held to current levels, or perhaps increased only very modestly, even if future budgets and spending are increased fairly dramatically as the Savings Goal and Budget Setting paper suggests would be appropriate.

Table 3: Energy-Efficiency Gas Incentive Caps per Unit of Gas Sales

	Total Gas Sales (m3)	Gas Sales Reference Year	Total DSM Budget	Budget Reference Year	DSM Budget per m3 Sales	Max Utility Incentive $	Max Utility Incentive % of DSM Budget	Max Utility Incentive per 1000 m3 Sales
Ontario Utilities								
Enbridge	11,300,100,000	2012	$30,910,000	2012	$0.0027	$10,450,000	34%	$0.92
Union	14,617,390,000	2012	$30,910,000	2012	$0.0021	$10,450,000	34%	$0.71
Other Examples								
Massachusetts	6,319,346,456	2012	$191,766,032	2015	$0.0303	$6,930,855	4%	$1.10
Michigan	13,366,672,182	2012	$ 73,487,238	2013	$0.0055	$11,023,086	15%	$0.82

Types of Performance Metrics

The types and general structure of performance incentive metrics that the OEB promoted through its 2011 DSM Guidelines and that the utilities and other stakeholders refined through settlement negotiations and subsequent DSM plan filings are very good and consistent with best practice across North America. In particular, as in Ontario (for gas utilities) today:

- Leading jurisdictions typically have multiple performance metrics to address multiply policy objectives;
- Consistent with the point above, total energy savings, low income savings (and/or participation levels) and market transformation are objectives for which it is common to see specific, targeted performance metrics;
- The industry has begun to focus greater attention on total lifetime energy savings rather than just first year savings;
- Many leading jurisdictions establish a minimum level of performance below which no shareholder incentive is earned – that minimum level is typically in the range of 75% to 80% of budgeted goals;
- Many leading jurisdictions establish continuums between the minimum threshold required to earn any incentive, the budgeted goal levels and exemplary performance

[11] Comparisons to Massachusetts and Michigan are provided because anecdotal evidence suggests that utilities in both jurisdictions find their performance incentives to be substantial enough to have attracted management attention and interest.

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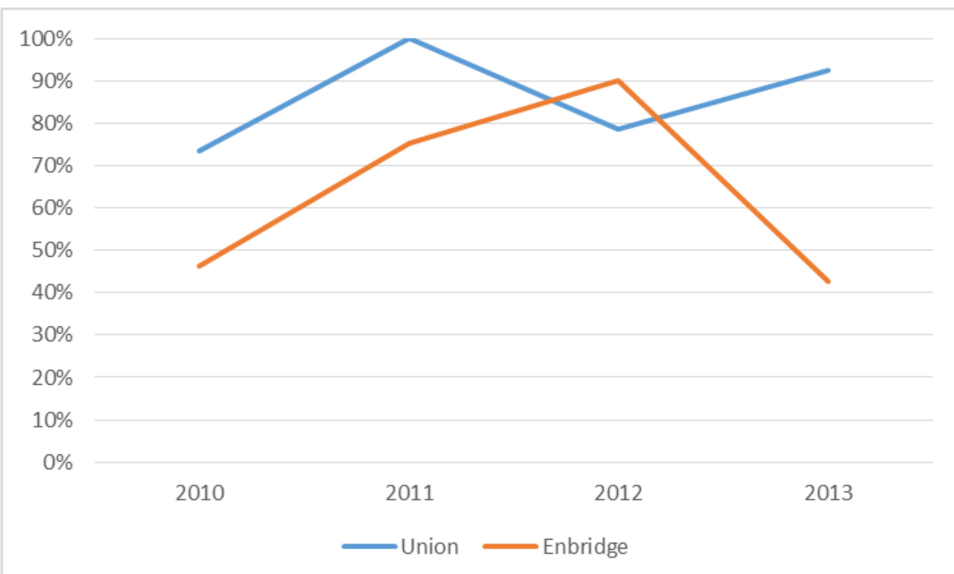
levels (often on the order of 115% to 125% of budgeted goals), with incentives increasing as performance improves along those continuums.

In general, utilities should only be earning the maximum incentives for performance that is truly exemplary. Put another way, incentive targets that the LDCs find easy to reach should move steadily upward. As Figure 1 shows, in recent years Union Gas has achieved or come close to achieving its maximum incentive most years. On the other hand, though Enbridge Gas has earned an incentive, its earnings have been lower – less than half of the maximum it has been eligible to earn in two of the past four years. These trends warrant careful examination to determine whether the differences are attributable to much better performance by Union or just to more aggressive goal-setting for Enbridge.

Figure 1: % of Maximum Incentive Earned By Union Gas and Enbridge Gas[12]



Computation of the Incentive Scorecards

In addition, as discussed below, there are some quirks in the way the 2011 DSM Guidelines established the "scorecard" approach to weighting the importance of different performance metrics that likely had unintended consequences and should be revisited.

[12] Values unadjusted for recent Board decisions on Union's 2011 results and Enbridge's 2012 results. 2013 values for Union are prior to any audit adjustments or possible OEB adjustments; 2013 values for Enbridge also are prior to any possible OEB adjustments.

Incentive for uneven attention to metrics

Under the Board's 2011 Gas DSM Guidelines,

> No incentive will be provided for achieving a scorecard weighted score of less than 50%. …. 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[13].

In other words, each program group (scorecard) stands or fall on its own. If a utility misses the minimum incentive mark for a program group, it loses the opportunity to earn the portion of the incentive allocated to that program group; if it exceeds the performance required for the allocated incentive cap for the program group, it gets no incremental incentive for that group. However, individual program groups (scorecards) often contain multiple performance metrics. Under the existing guidelines, a utility can totally fail one metric, exceed the high target on another metric, and still get the maximum incentive for the program group.

The treatment of the metrics above the upper bands encourages the utilities to pile on resources for the metrics that prove easy to achieve and to neglect the metrics that are harder to achieve. This is particularly true where the increase in incentive per unit of performance above the middle target is larger than the decrease in incentive per unit of performance below the middle target.

Potential for unintended over-weighting of metrics

Under the current approach, the stakeholders may agree on a new metric, to encourage the utility to move in a new direction, but without any clear idea of how difficult that metric will be to achieve. Even if the incentive mechanism gives that metric a low weight, such as 5%, that single metric may turn out to be easy to exceed and the utility may exceed the metric several times over. The 5%-weighted metric can end up contributing 25% or more to the utility's achieving the overall scorecard target. This feature of the weighting greatly reduces the meaningfulness of the metric weights, and can easily distract the utility from metrics that are given higher nominal weights towards relatively minor metrics on which the utility finds it can run up the score.

[13] OEB, 2011, DSM Guidelines for Natural Gas Distributors, p. 32.

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Inconsistent distinctions between program groups

The distinctions between the program groups and the metrics are not consistent or logical. For example, in the 2013 Draft Evaluation Report, Enbridge treats three metrics for the low-income programs (single- and multi-family m^3 and LIBPM participation) as a single program group, but splits the six metrics in the market transformation programs into four smaller program groups. While the over-performance on low-income single-family m^3 and LIBPM are able to offset some of the under-performance on low-income multi-family m^3, the over-performance on drain-water heat recovery and commercial Savings By Design (SBD) cannot offset any under-performance on other market transformation metrics. The over-performance on the number of realtors committed to home labelling can offset the shortfall in ratings performed (since they are both part of the home-labeling component), but not the failure to earn the maximum incentive for the residential SBD program.

Recommendation

The incentives would be more consistent and effective if each metric were allocated a portion of the incentive cap, without any opportunity for performance above the high target or upper band to offset any failure to meet the high target for other metrics. This is already the case for Enbridge's incentives for drain-water heat recovery and commercial SBD and Union's incentives for Large Industrial scorecard. That approach should be extended to the other metrics.

Additional and Modified Metrics

Deep Savings

Some of the metrics for deep savings do not appear to represent very deep savings, such as Union's 2012 commercial/industrial target of 5.5% average savings. Deep-savings incentives should be directed to increasing penetration of truly deep savings, such as reductions of more than 30% in existing buildings and construction of new buildings to 20% below the requirements under existing codes and standards.

Since deep savings for a particular non-residential facility or multi-family building can take a few years of sequenced improvements, providing incentives for truly deep savings may require that the metric be defined over a longer period than one year. For example, the metric might count the m^3 saved in buildings that have saved 30% or more over the previous five years.

Lost Opportunities

More fundamentally, the incentive scheme should restore a form of the Board's lost-opportunity metric, based on after-the-fact independent evaluation of whether programs are encouraging participants to go as far as is cost-effective (i.e., maximizing inches of attic insulation, furnace AFUE or window U value) or achieving substantial increases in market shares for key efficiency technologies or practices (e.g. Energy Star-certified new homes).

Geo-targeting

Finally, the Board should consider, where appropriate and relevant, introducing a geo-targeting metric to reward the utilities for identifying and relieving areas that will otherwise require transmission and distribution reinforcement. In the recent GTA transmission cases, it was revealed that Enbridge has long known of emerging load-related capacity constraints on its transmission system, which would require hundreds of millions of dollars for the GTA projects in segment B, and \$10–\$20 million annually in load-related reinforcements in parts of the GTA, but had not reflected any of those savings opportunities in DSM planning. A geo-targeting metric should consist of an external evaluation of the utility's process for identifying potential reinforcement requirements over the next decade, designing enhanced DSM efforts to avoid those reinforcements, and implementing those enhancements.

Conclusions

Recent trends in the gas utilities' incentive earnings should be examined to determine whether incentive thresholds are set at appropriate levels, and to ensure that utilities are only earning the maximum incentives for truly exemplary performance. Comparison with other North American jurisdictions suggests that incentive levels in Ontario should be held to current levels or increased only very modestly even if utilities' DSM budgets increase dramatically. Existing performance incentive metrics are generally consistent with best practice across North America, but could be made more effective if each performance metric were allocated a portion of the incentive cap, if incentives encouraging deep savings were more appropriately targeted, and if metrics to encourage geo-targeting and avoidance of lost opportunities were introduced or reintroduced.

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2014 OEB Gas DSM Framework Issue Paper:

Gas-Electric Integration

On March 31, 2014, the Ontario Energy Minister issued a directive that the OEB establish a gas DSM framework that will enable the province's regulated gas utilities to acquire all cost-effective energy efficiency resources. The directive also states that the new framework should ensure that the gas utilities, where appropriate, "coordinate and integrate" their efficiency programs with the electric programs offered by both the Ontario Power Authority (OPA) and local distribution companies. This paper addresses opportunities for and ways the OEB could foster greater coordination and integration. Note that though the directive focuses solely on gas-electric DSM coordination, this paper looks at the issue a little more broadly, including consideration of opportunities for greater coordination between the province's two gas utilities.

Defining Coordination and Integration

Any discussion of DSM program coordination and integration must start with clarity about what those two terms mean. For the purpose of this paper, "coordination" is taken to mean that, at a minimum, there is consistency in the design of the program. That should include:

- Identical definitions of "efficiency" – i.e. the same level of efficiency, relative to baseline efficiency levels, is promoted province-wide,
- Consistency in program marketing/messaging to trade allies and consumers,
- Identical training curricula (where applicable),
- Identical quality assurance standards,
- Rebate (or other financial incentive) offerings that are designed with both gas and electric contributions in mind (i.e. sufficient *in combination* across fuels to induce significant customer participation)
- Consistent rebate (or other financial incentive) levels across the province (i.e. identical for all electric utilities and identical for all gas utilities), and
- Identical metrics of success (for market transformation programs).

For the purpose of this paper, "integration" is taken to mean joint delivery. That is, though each participating utility may have its own internal program administration, all program delivery services – whether training of trade allies, program marketing, direct installation of efficiency measures, quality assurance inspections or reviews, rebate processing, etc. – are provided by a single entity operating on behalf of two or more utilities. That is commonly accomplished by hiring one or more firms, which multiple utilities jointly select, to deliver program services. The work of those firms can be either managed jointly or by a single utility designed or chosen by the group (sometimes with different utilities taking the lead on different programs as a way to share efforts). However, it could theoretically also be accomplished by a single utility providing such services and then "billing" the collaborating utilities for their portion of the costs. In the end, the key attributes of integrated or jointly delivered programs are:

- A single, identical, consistent program design across fuels and geography;
- A single set of marketing materials (typically jointly branded);
- A single customer application for participation (e.g. a single rebate form);
- A single point of contact for customers and trade allies;
- A process in place for cost-sharing across participating utilities; and
- A process in place for joint program management and decision-making.

As described above, coordinated and integrated programs are two ends of a continuum for multi-utility DSM program collaboration. There can obviously be points in between as well. Specifically, it is possible to have a coordinated program of which only parts are jointly delivered (and parts are individually delivered).

Rationale for Greater DSM Program Coordination and Integration

There are a variety of potential benefits from greater coordination and/or integration of DSM efforts between utilities (and/or non-utility program administrators). These are summarized in Table 1 below.

Table 1: Potential Benefits of Coordinated and/or Integrated DSM Programs

Issue	Benefits	Gas-Gas Benefits	Gas-Electric Benefits
Program Costs	Integrated/Joint delivery of programs across utilities can lower overhead costs – e.g. costs for training, marketing, quality assurance and some administration – by reducing redundancy and spreading fixed costs across a greater volume of savings. An added benefit for gas-electric integration is the ability to share rebate (or other financial incentive) costs.	Yes (some)	Yes (more)

Enhanced Reach	Both coordinated and integrated/joint programs targeting the same efficiency products or services can enable engagement of trade allies, manufacturers or others that might otherwise have not been possible. It can even enable the delivery of a program that might not have otherwise been possible. This is partly related to the program cost savings noted above, and partly a function of the critical mass that is sometimes necessary to effectively engage trade allies.	Yes	Yes
Market Clarity	Both coordinated and integrated/joint programs should result in more consistent messages about the efficiency products and services consumers should buy, the benefits of those products and services, where and how they can be acquired, etc. Conversely, uncoordinated programs that promote different efficiency levels to the same customers (gas and electric) and/or to retailers, vendors, contractors, builders, etc. who work with customers in different service territories can create market confusion. Greater market clarity typically leads to greater program participation and, therefore, greater savings per dollar spent.	Yes	Yes
Lower Transaction Costs for Consumers	Integrated/joint programs are typically easier for customers to access because there are fewer forms to complete, fewer program staff with which to interact, fewer site visits by program staff required, etc. As a result, they typically result in greater program participation and, therefore, greater savings per dollar spent.	In some cases (e.g. chains or national accounts)	Yes
Greater Prospects for Market Transformation	Almost by definition, long term market transformation requires the kind of consistency in program design, messaging and delivery that comes from at least coordinated programs if not integrated/joint programs.	Yes	Yes

Of course, there are also some costs to coordinating and/or integrating the delivery of programs. In particular, extra time and effort is required by utility staff to reach out to other utility staff and negotiate details of program design, delivery and/or management. Depending on the nature of the working relationships, it can also be more difficult to make quick changes to programs in response to market feedback. Such costs tend to be highest initially, but then decline as utilities develop trust and systems for working together. In general, most DSM experts believe that benefits outweigh the costs, at least for certain types of programs (see below).

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When DSM Program Coordination and/or Integration Should Be Pursued

There are almost always advantages to at least coordinating, if not integrating, delivery of DSM programs, both across multiple gas utilities and between gas and electric utilities. However, it is more important for some types of programs than for others. It is particularly critical for the following four types of programs:

- **Market Transformation Programs.** Transforming markets requires either changing social norms at the consumer level; changing norms of manufacturers, vendors, retailers, contractors, builders and/or other key trade ally groups; and/or facilitating the adoption of new government regulations (codes and standards) which, in turn, typically requires enough of a change in the market (e.g. a substantial enough market share for a product) so that the government is not perceived as being too far ahead of the curve. Changing social norms or the norms of trade allies or government regulations is not easy and typically requires clear, consistent and uniform efforts and messaging. Moreover, many key trade allies (e.g. manufacturers, large builders, large distributors, etc.) require assurance that they will have a sufficiently large market for a new product or service before they will consider changing their behavior and business plans. That typically necessitates having all parties in a particular jurisdiction – and sometimes even across multiple jurisdictions – promoting the same efficiency product or service in the same way.
- **Mass Market Programs**. For products that are sold in relatively large numbers – usually to residential and/or small commercial customers – it is important that DSM programs make the transactions for retailers, contractors, vendors and other trade allies, many of whom serve customers in multiple utility service territories, as easy and simple as possible. This is important for several reasons. First, the profit per product is often too small to make the transaction costs of dealing with multiple programs worthwhile. Second, the individuals selling the products often do not have the capacity to understand and convey to customers multiple program offerings. Third, sales people cannot always easily determine which utility serves the customer with which they are currently interacting, making them less willing to work with multiple different programs. In addition, sales staff for retailers and many other trade allies often turn over quickly, making it even more challenging to ensure multiple messages for different utility customers are conveyed appropriately.
- **Multi-Measure/Whole Building ("Deep Energy") Retrofits**. When examining whole buildings for energy-saving retrofit potential, assessments should include all fuels used by the building. Pursuing multiple measures to save both gas and electricity (and water)

can yield greater savings, greater GHG reductions, and provide a building owner with a shorter payback and better return on investment than pursuing gas-saving measures alone. Coordinating gas and electric program delivery can facilitate a building-focused (rather than measure-focused) approach to improving energy efficiency, and can exploit synergies between gas and electric measures that enable deeper savings than would be possible if measures were pursued in isolation.

- **Would-be Stranded Opportunities.** In the same vein, some retrofit programs cannot be justified by the savings for just one fuel. For instance, it can be challenging for an electric utility to run a program targeted to a gas-dominated market where electricity users are the minority – there simply may not be enough electric savings available to justify the fixed costs of running a program. However, a gas utility running a DSM program in the same market has no incentive to capture cost-effective electric savings. In such cases, it is important for gas and electric utilities to collaborate on program design and delivery so that the greatest "bang for the buck" across all fuels can be realized.

Challenges to Coordinating and/or Integrating Programs

There are certainly challenges to coordinating and/or integrating efficiency programs. Chief among these are figuring out how to work together. However, experience in numerous jurisdictions – including Vermont, Massachusetts, Connecticut, Illinois, California and others – clearly demonstrates that these obstacles can be overcome.

A variety of approaches to working together have been successfully tested. Where multiple utilities (rather than just two) are involved, it is common to have regular, structured meetings – initially to work out the design of programs, but just as importantly to manage those joint programs as they are delivered and refined. One example that has been in place since the 1990s is the Massachusetts Joint Management Committee (JMC) in which the state's several electric and several gas utilities have managed a statewide residential new construction program through a number of evolutions over time. A variety of other examples are cataloged in a forthcoming ACEEE publication on combined gas and electric efficiency programs (expected publication is August 2014).

As one might expect, often one of the trickier aspects of working together is developing a protocol for how to share costs of jointly delivered programs. Several different approaches have been used in different jurisdictions. Perhaps the fairest is:

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- to require each utility to pay for the financial incentive offered for any measures that save only that utility's fuel (this applies to both joint delivery between multiple gas utilities, between multiple electric utilities and/or between gas and electric utilities);
- to allocate the cost of other measures that save multiple fuels in proportion to the net present value of the electric and gas benefits (this applies only to joint delivery between gas and electric utilities); and
- to allocate non-measure costs such as marketing, training, quality assurance, evaluation and jointly funded administration, in proportion to the net present value of the benefits of the program as a whole to each participating utility (this applies to both joint delivery between multiple gas utilities, between multiple electric utilities and/or between gas and electric utilities).

This approach is currently being used in northern Illinois (the Chicago area) in collaboration between Commonwealth Edison (the electric utility) and Nicor Gas, People's Gas and North Shore Gas. It has been used in other jurisdictions as well.

One disadvantage to this approach is that it can require periodic adjustments to cost allocations when there are changes in avoided costs (which in turn lead to changes in the distributions of benefits). However, that appears to have been eminently manageable in the jurisdictions where this approach has been used.

Of course, there are also other, simpler ways to allocate common costs, including allocations based on site energy savings (expressing electric and gas savings in a common format, such as joules), based on source energy savings or based on even simpler negotiated fixed percentages.

Coordination and/or Integration in Ontario

One might expect that coordination and integration would be a little more challenging in Ontario than in other jurisdictions for a couple of reasons. First, there are more than 70 electric distribution companies with which the province's gas utilities would potentially need to work. Second, the OEB does not have quite the same level of oversight authority over the Ontario Power Authority's DSM programs as it does over the province's gas programs[14]. However, those challenges do not fully explain the fairly limited degree of cross-utility collaboration to date.

[14] Though it should be noted that the OEB reviews the OPA's administrative budget and the potential economies of scope and scale associated with gas-electric collaboration should inform that review. Further, the OPA should be amenable to coordination or integration given the explicit government policy in the directive to the OEB.

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First, it is worth emphasizing that greater coordination and integration of Enbridge Gas and Union Gas DSM efforts – i.e. gas-gas collaboration – should be comparatively easy. However, it has been fairly limited to date. To be sure, the creation of the province-wide Technical Evaluation Committee (TEC), in which both gas utilities are working together with stakeholders to jointly develop evaluation priorities and jointly manage province-wide evaluation studies, is a positive step forward. However, more can and should be done. For example, it is worth noting that though both utilities have residential new construction market transformation programs in the 2012-2014 plans, the two programs are substantially different. Enbridge is working with builders on integrated design processes to achieve 25% savings relative to the current Ontario building code while Union is promoting the construction of new homes that are 15% more efficient than the code. Needless to say, it will be harder to transform the market when two different efficiency standards are being promoted! In its next gas DSM guidelines, the OEB should require that the two gas utilities have, at a minimum, the same market transformation programs. They should also be required to collaborate on the design and, where cost-efficient, joint delivery of mass market programs targeted to residential and small business customers (i.e. on the sale and purchase of efficient products sold to those customers).

With respect to gas-electric collaboration, while the existence of more than 70 LDCs theoretically makes collaboration potentially very challenging, the reality is likely less complicated. First, the five largest electric LDCs account for about 60% of electricity sales in the province.[15] Moreover, most of the electric efficiency programs run in the province originate with the Ontario Power Authority (OPA). Thus, the OEB could require that the gas utilities endeavor to reach agreement with the OPA and at least the largest electric LDCs on common program designs and, where cost efficient and/or necessary to avoid creation of lost opportunities, joint delivery of parts of all of those programs. That said, collaboration should not be required at all costs. If the price of collaboration would be standards that are too low, rigidity in the face of quickly changing market conditions or other adverse impacts, the affected utilities should be expected to back away from collaboration.

In sum, at a minimum, the gas utilities should be required to document in their plans the program areas in which they succeeded in collaborating or attempted to collaborate with electric DSM efforts and, where efforts to collaborate ultimately failed, to explain why. Put another way, there should be a burden imposed on the gas utilities to demonstrate that the failure to collaborate on programs which could potentially benefit from collaboration was in

[15] Ontario Energy Board, 2012 Yearbook of Electricity Distributors, August 22, 2013 (http://www.ontarioenergyboard.ca/oeb/_Documents/RRR/2012_Electricity_Yearbook_excel.xls).

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rate-payers best interests. The Board and other parties will need to accept that there will be some subjectivity to make such determinations. Of course, the OEB should also use all means at its disposal to encourage the OPA and the electric LDCs to pursue productive collaboration with the gas utilities whenever possible.

Fuel-Switching – Another Aspect of Integration

The discussion above focused exclusively on multi-utility collaboration on the design of efficiency programs. One additional, related, gas-electric integration topic that merits consideration is fuel-switching. Fuel-switching is not very common in most utility efficiency program portfolios, in large part because utilities often resist measures that shift load to another fuel. However, depending on the circumstances, such shifts can be economically cost-effective, environmentally beneficial and result in lower total energy use (the ultimate definition of efficiency).

The current OEB Gas DSM framework appropriately allows the gas utilities to pursue fuel-switching away from gas as part of their DSM efforts as long as the fuel-switching is economic and leads to a net reduction in greenhouse gas emissions. To date, that option has received very little attention.[16] However, it may merit much greater attention in the future for a couple of reasons.

First, studies in both California[17] and Europe[18] suggest that the most likely path to meeting long-term carbon emission reduction requirements includes substantial electrification of building space heating, water heating and other end uses (as well as cars), coupled with the de-carbonization of the electric grid and massive investments in cost-effective energy efficiency.

Second, recent advances in both the efficiency of electric heat pumps and their ability to function effectively in cold climates, has brought that technology to the point where it could be (or at least could become) competitive with natural gas heating alternatives, depending on local energy prices.[19] For example, cold climate ductless heat pumps currently produced by

[16] Enbridge Gas has supported fuel-switching to ground source heat pumps in a couple of commercial building new construction projects.
[17] Energy and Environmental Economics, Inc., *Meeting California's Long-Term Greenhouse Gas Reduction Goals,* November 2009.
[18] European Climate Foundation, *Roadmap 2050, A Practical Guide to a Prosperous, Low-Carbon Europe,* April 2010 http://www.roadmap2050.eu/
[19] If the local price for electricity is $0.14/kWh, the average 2013 Ontario price for consumption of about 1000 kWh per month (http://www.ontario-hydro.com/index.php?page=electricity_rates_by_province), then a heat pump with an efficiency of 280% to 300% will produce heat at the same cost as an 80% efficient gas furnace system (including distribution losses) using gas that costs $0.39 to $0.42/m^3 – not much higher than the current marginal

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Mitsubishi and Fujitsu can maintain their nameplate capacity down to -15˚ C (whereas air source heat pumps of the past cold not operate without inefficient electric resistance back-up much below freezing) and still produce heat below -25˚ C (though at reduced capacity). Though the efficiency of these systems does decline as temperatures fall, recent field tests in central New Hampshire[20] and Idaho[21] – locations with winter conditions similar to if not colder than Toronto – suggest that one can expect an average seasonal efficiency of 280% to 300%. In other words, if one is using electricity produced by a gas turbine with an efficiency of 45% and losing 10% of that power through transmission and distribution system losses, the net source efficiency of the heat provided is 113%[22] - well above what is possible with the best gas furnace (i.e. ~98%, even assuming no distribution losses). If nothing else, the new cold climate heat pumps ought to be very carefully considered as an efficiency improvement in buildings using electric resistance heat, particularly if the building owners are considering the alternative of switching to gas heat.

On the other hand, combined heat and power (CHP) systems have the potential to consume slightly more gas but less total energy to meet heat and power needs than if the customer relied on the central electric grid for power and a separate gas boiler for space heating.

In short, given both long-term climate policy imperatives and economics – i.e. what is cost-effective – the OEB should begin to require greater consideration of fuel-switching. In particular:

- any efficiency potential studies – gas and electric – should be required to explicitly examine fuel-switching options to determine when they are cost-effective;
- utilities should be encourage to pursue fuel-switching away from their fuel whenever it is cost-effective and reduces greenhouse gas emissions;

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cost of gas to residential customers in the province. Of course, one must also consider forecasts of how electric and gas prices will change in the future, the costs of the heating systems themselves, whether a gas hook-up is required (with its attendant costs) and other factors. However, the bottom line is that heat pump technology has advanced to the point where this analysis has become necessary.

[20] Energy & Resource Solutions, *Emerging Technology Program Primary Research – Ductless Heat Pumps*, prepared for the Northeast Energy Efficiency Partnerships, May 2014 (http://www.neep.org/Assets/uploads/files/emv/emv-library/NEEP%20DHP%20Report%20Final%205-28-14%20and%20Appendices.pdf).

[21] Baylon, Dave et al. (Ecotope, Inc.), *Ductless Heat Pump Impact & Process Evaluation: Field Metering Report*, prepared for the Northwest Energy Efficiency Alliance, Report #E12-237, May 1, 2012 (http://neea.org/docs/reports/ductless-heat-pump-impact-process-evaluation-field-metering-report.pdf?sfvrsn=16). See, in particular, results for the two Idaho locations.

[22] 0.45 * 0.90 * 2.80 = 1.13

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- utilities should be precluded from subsidizing conversions to their fuel (whether through DSM or non-DSM means) unless they can demonstrate that such conversions are cost effective and reduce greenhouse gas emissions.

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2014 OEB Gas DSM Framework Issue Paper:

Are Ontario Gas Utilities' Efficiency Programs Worth It?

Across Canada, the United States and beyond, electric and gas utilities are running programs to help homeowners and businesses invest in energy efficiency. Those programs typically include rebates or other financial incentives to buy different efficiency products and services, as well as efforts to educate consumers on their benefits. The programs are typically funded by all of the utilities' customers through small charges on their monthly electric and/or gas bills or built into their rates.

In Ontario, both Enbridge Gas and Union Gas have run such programs since the 1990s. Together, they currently spend roughly $70 to $80 million per year,[23] but are still capturing only a modest portion of the cost-effective gas efficiency potential in the province. The Ontario Energy Minister recently instructed the Ontario Energy Board (OEB) to establish a new regulatory framework that would result in the province's gas utilities acquiring all cost-effective energy efficiency. A healthy debate is currently underway among various stakeholders and within the OEB about what that means and how to accomplish it.

It is important to note that the OEB – like similar regulators in other provinces and states – has always required that the utilities' energy efficiency programs be cost-effective – i.e. that the dollar savings over the life of the efficiency improvements are greater than the costs of the programs. Assessments of cost-effectiveness are based on determinations of the components of current energy bills that can be avoided (and which cannot) by using less energy, on forecasts of future energy prices, on assumptions about how to discount the value of benefits that accrue in the future, and on a variety of other assumptions. Those sophisticated approaches to assessing cost-effectiveness may be appropriate for regulators and others who are involved in the arcane nuances of these issues, but can be difficult for the average consumer to understand. The following attempts to distill the key aspects of the cost-effectiveness of the gas utilities' conservation programs to date, and what that suggests about the design of the new policy framework and future programs.

[23] This includes the cost of incentives the utility shareholders can earn if the utilities do a good job and meet or exceed energy savings targets and/or other related goals.

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Utility Efficiency Program Costs

The simplest way to look at the cost of utility-run efficiency programs is to compare how much the utility spent per unit of energy saved, over the life of the savings (recognizing that many efficiency measures, such as insulating a home, will save gas for many years). The Ontario results for 2012 are as follows:

- Enbridge Gas' energy efficiency programs cost an average of just \$0.06 per m^3 of gas saved.[24]
- Union Gas' programs cost even less – an average of just \$0.03 per m^3 of gas saved – mainly because it has more large industrial customers for which efficiency savings are usually less expensive.
- The average customer currently pays on the order of \$0.30 to \$0.35 per m^3 consumed, even after one excludes the fixed monthly charge.

DSM	Gas
3¢ - 6¢ per m^3	30¢ - 35¢ per m^3

Total Economic Value to the Province

A more complex way to look at whether utility-funded efficiency programs make economic sense is to compare the total cost of the programs – both what the utilities spent, plus what their customers spent on the efficiency measures[25] – to the value of the savings.

Historically, the Ontario utilities have taken a very conservative approach to estimating the economic value of efficiency. They have counted all the costs, but only a portion of the benefits – mostly just the value of the gas fuel, and the value of electricity and water savings (many efficiency measures that save gas, such as insulating buildings or installing low-flow showerheads, also save electricity or water).

They have traditionally ignored the value of reduced investment in new pipelines; the value of reduced environmental emissions; the benefits of lowering gas prices;[26] and value of improved comfort, improved business productivity and other non-energy benefits to its customers.

[24] This is the "levelized cost" of gas saved. It takes Enbridge's total spending on its efficiency programs, plus the payments its shareholders received for doing a good job, and spreads them out over the roughly 18 years that the savings from its efficiency programs will last on average, just like the purchase price of a house is translated to a monthly payment for a mortgage, to account for the fact that the spending occurs once but the savings recur (with related bill savings) for many years.

[25] For example, if an efficiency measure costs \$100 and the utility provides a \$30 rebate, the customer must pay the other \$70. In this analysis of the net economic value of efficiency programs, both of those components of the efficiency costs are included.

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Nevertheless, even using the utilities' very conservative estimates of the benefits of efficiency, their 2012 programs were extremely cost-effective.

- Union Gas estimated that its customers will realize over $310 million in gas, electric and water bill savings (mostly gas) for a *total cost* of about $80 million (*total cost* includes the $31 million cost of Union's programs, plus the added expenditures customers make themselves). From just one year of running its efficiency programs, Union and its customers produced over $230 million in net savings to consumers.
- Enbridge's estimates of the economic benefits of its 2012 efficiency programs are not currently publicly available. However, in its plan for that year it estimated it would achieve approximately $150 million in customer bill savings (again, mostly gas, but some electricity and water too) at a *total cost* of about $42 million (*total cost* includes the $31 million cost of Enbridge's programs, plus the added expenditures customers make themselves). Thus, from one year of running its programs, Enbridge estimated it would produce $108 million in net savings to consumers.[27]
- Ontario consumers are saving in the order of $338 million (net), with utility investment of just $62 million.

Economic Development Benefits

Investment in efficiency tends to be more labor intensive and more local than spending on gas which is imported from distant provinces and/or states. Thus, local insulation companies and vendors of other efficient products can add jobs as a result of these programs.

In addition, the cost savings discussed above have rippling effects through the provincial economy:

- Lower bills mean businesses are more competitive with business in other jurisdictions, protecting and potentially supporting expansion of jobs.
- Lower bills for business can also mean lower prices for some products for Ontario customers.
- Lower bills mean customers have more disposable income to spend on other products, often purchased from local stores, restaurants and/or other service providers. That, in turn, helps protect or even add jobs to the economy.

[26] The basic law of supply and demand says that when demand goes down, prices go down – even if only a little.
[27] This is likely an under-estimate of the actual net economic benefits since Enbridge reported significantly exceeding its savings targets for the year.

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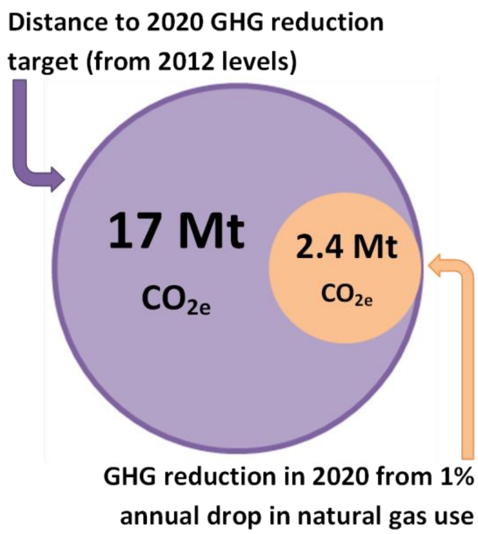
Put simply, cost-effective efficiency programs are one of the best ways to spur local economic development.

Environmental Benefits Too

The 25 billion cubic meters of natural gas used annually in Ontario are directly responsible for almost 50 million tonnes of greenhouse gas emissions, which is about 30% of the province's emissions.

- The gas efficiency measures the two Ontario gas utilities' programs caused to be installed in 2012 will reduce carbon dioxide emissions by 6.4 million tons.[28] That is equivalent to taking 1.75 million cars – or nearly one-quarter of Ontario's cars and light trucks – off the road for a year.[29]
- Reducing natural gas use by just 1% per year starting in 2015 would lower Ontario's 2020 GHG emissions by 2.4 megatonnes – that represents about 15% of the distance from Ontario's 2012 emissions to 2020 GHG target.



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[28] Estimate is based on the reduction in carbon dioxide emissions associated with the efficiency measures installed as a result of the utilities' resource acquisition programs (over the expected life of the savings). It is conservative in that it does not account for energy savings from the utilities' market transformation programs, the emission reductions associated with the electricity savings the utilities' efficiency programs also produce, or the methane emissions (methane is a more potent greenhouse gas than carbon dioxide) associated with producing and distributing natural gas.

[29] Based on NRCAN estimates of emissions per liter of gasoline and 2009 estimates of the average liters of gas used per 100 km, the average km driven annually and the number of vehicles on the road in Ontario.