EB-2012-0337

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15, Schedule B; and in particular section 36 (2) thereof;

AND IN THE MATTER OF an application by Union Gas Ltd. ("Union Gas") for an Order or Orders approving its 2013-2014 Large Volume Demand Side Management ("DSM") Plan.

ENVIRONMENTAL DEFENCE

CROSS-EXAMINATION REFERENCE BOOK (Union Gas 2013-14 Large Volume DSM)

January 28, 2013

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Note: The above are all excerpts of the relevant materials, except for item 9.

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[1] http://www.eco.on.ca/uploads/Reports-Energy-Conservation/2012v2/12CDMv2.pdf
[2] http://on.cme-mec.ca/download.php?file=gc95me9a.pdf
[3] http://www.eco.on.ca/index.php/en_US/pubs/greenhouse-gas-reports/2012-greenhouse-gas

TAB 1

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1. INTRODUCTION

On January 31, 2012, Union Gas Limited ("Union") filed the EB-2011-0327 – 2012 - 2014 Demand Side Management ("DSM") Plan Settlement Agreement ("Agreement"). The Agreement included a Large Industrial DSM program for 2012 only. As part of the Agreement Union committed to file a new application and evidence with the Ontario Energy Board ("Board") supporting a Large Industrial Rate T1 and Rate 100 DSM plan for 2013 and 2014 prior to September 1, 2012. The Board accepted the Agreement on February 21, 2012. Accordingly, Union has developed a new Large Volume DSM Plan ("Plan") for the years 2013 and 2014. Although the DSM Guidelines for Natural Gas Utilities ("Guidelines") dated June 30, 2011 (EB-2008-0346) and the Agreement, refer to the customers within Rate T1 and Rate 100 as "Large Industrial", Union has termed this Plan as Large Volume to recognize that customers within these rate classes have end uses that are not exclusively industrial in nature. The Plan includes a single Large Volume Program (the "Program") outlined in Section 6.

In Union's 2013 Cost of Service Application (EB-2011-0210) Union proposed to split the current Rate T1 into two rate classes with distinct rate structures; a new Rate T1 mid-market service and a new Rate T2 large market service. If approved by the Board, Union proposes to implement the new rate classes, eligibility changes and rate structures, on a revenue neutral basis, effective January 1, 2013. The Plan is premised on the Board's approval of the proposed split of Rate T1. In the event the Board does not approve Union's proposal related to Rate T1 and Rate T2, Union will modify the Plan as discussed in Section 8.

Union has prepared the Plan in compliance with the Board's Guidelines. Union will continue to follow the framework elements approved in the EB-2011-0327 proceeding as they relate to the Plan. Specifically, the process for the Lost Revenue Adjustment Mechanism ("LRAM"), DSM Variance Account ("DSMVA"), DSM Incentive Deferral Account ("DSMIDA"), DSM Program Screening, Avoided Costs, Stakeholder Terms of Reference and Low-Income program cost recovery are not impacted by the Plan. Union is seeking approval of the Plan effective January 1, 2013.

Intervenor Consultation on 2013 – 2014 Large Volume Rate T1/Rate T2/Rate 100 DSM Plan

On August 15, 2012, Union held a Consultative meeting with intervenors and interested parties. At the consultation, Union presented its 2013 – 2014 Large Volume DSM Program proposal, budget and annual scorecards, and feedback was provided by stakeholders. Following the consultation, Union circulated its presentation to the Consultative, including those not able to attend. In addition, Union offered stakeholders who attended the meeting the opportunity to review the summary of feedback received at the Consultative session to ensure it reflected their input and provide additional written comments on the Plan. The material provided to Union's Consultative, invitation and attendance list are provided in Appendix G. A summary of the feedback received and Union's position, including changes made from the original Plan proposal to the final Plan, is provided in Appendix H.

Union notes that although it consulted with stakeholders when developing the Plan and incorporated, where in Union's view appropriate, the feedback provided through consultation, it does not have consensus on the Plan. While some customers and stakeholders liked the program proposal, others indicated that they would like to opt-out of the Plan, thereby avoiding any costs associated with providing DSM programs or DSM related deferral account disposition. Union addresses its reasoning for not offering an opt-out option in Section 7. It is Union's view that the Plan is consistent with the Guidelines while balancing the goals of the Board and the interests of Union, its customers and its stakeholders.

1.2 Union's 2013 – 2014 Large Volume Program Overview

Union's Board-approved 2012 Rate T1/Rate 100 program is targeted to all customers within these rate classes. It includes the following five offerings: customer engagement, engineering feasibility and process improvement studies, O&M optimization, new equipment and processes, and energy management. The 2012 post-inflation program budget is $4.664 million. This budget includes the incentives provided to customers who undertake energy-efficiency initiatives within their facilities. Customer incentive funds are dispersed via an aggregated pool approach where projects are supported based on their lifetime natural gas savings and cost-effectiveness.

In 2013 and 2014, Union is proposing to deliver the same program offerings and maintain a consistent program budget, escalated annually for inflation. All Rate T1[1] customers will maintain access to an aggregate pool of customer incentives throughout the year. This approach has been successful in driving projects for these customers historically and is consistent with the DSM program structure in Union's bundled contract rate classes that serve other similarly sized customers.

Union is proposing to change the customer incentive budget process for Rate T2 and Rate 100 customers to a new Direct Access budget mechanism. Instead of an aggregate pool approach, at the beginning of the year these customers will each have direct access to the full customer incentive budget they pay in rates. They must use these funds to identify and implement energy-efficiency projects, or lose the funds to be used by other customers in their rate class. This "use it or lose it" approach ensures each customer has first access to the amount of the customer incentive budget funded by their rates.

The Direct Access budget mechanism is being introduced in direct response to feedback received from Union's largest customers at the focus group sessions. Rate T2 and Rate 100 customers will have enhanced flexibility to access a greater level of incentives for individual large projects or studies. They will know their dedicated amount of customer incentive budget for the program year. This funding can be incorporated into their overall budget planning process with the knowledge that available funds will either be used for qualifying activities to deliver value to them, or the funds will be moved to the aggregate pool for use by others. By motivating each customer to take action with their available incentive budget, Union's program also aims to minimize intra-rate class cross subsidization. Additionally, Union has removed the ability to

[1] As per Rate T1 proposal in Union's 2013 Cost of Service Application (EB-2011-0210)

overspend the budget by 15% in Rate T2 and Rate 100 to provide greater rate certainty for these customers.

Union's program has also been informed by a Jurisdictional Review of programs in North America, provided in Appendix A. Some jurisdictions in the United States ("U.S.") offer self-direct or opt-out provisions whereby customers either pay a cost-recovery mechanism fee which can be "self-directed" into an internal energy-efficiency investment or the customer "opts-out" and is exempt from funding energy-efficiency programs. Union found no Canadian jurisdiction offering either of these program options today. In the U.S., with the exception of Vermont, none of the top twenty leading jurisdictions in industrial programming offer any form of an opt-out program. Ten of the top twenty, however, do provide self-direct programs. Union's Direct Access budget mechanism includes key elements of self-direct programs in other jurisdictions. It builds on these program models by continuing to provide technical assistance through its Account and Project Managers. This is in direct response to customer feedback regarding the high value placed on Union's technical resources. This technical support is not present in the majority of self-direct programs in other jurisdictions. In addition, the program will follow the evaluation, verification and audit protocols in the Guidelines and established through the Stakeholder Terms of Reference (e.g. Technical Evaluation Committee and Audit Committee process) to ensure reliable energy savings are generated. This is consistent with the rest of the DSM program portfolio.

Within an environment of competing production demands, limited resources and low commodity prices for natural gas, it is important to continually ensure energy-efficiency remains a priority for large volume customers. These customers have, and continue to generate, the most cost-effective natural gas savings within Union's program portfolio. Although some customers, such as power producers, have indicated that they would like to opt-out of the Plan, significant economically feasible efficiency opportunities remain in the province that large volume customers have not undertaken to-date. Union's Program will continue to support customers in identifying and realizing these energy savings. For industrial and power generation customers alike, Union has experienced consistent growth in the number of projects and cost-effective natural gas savings generated in its large volume rate classes. Union has provided a summary of its historical Rate T1 and Rate 100 cumulative natural gas savings and projects in Table 1 below.

Table 1: 2008 – 2011 Rate T1 and Rate 100 Cumulative Natural Gas Savings and Projects

	Customer Type	2008	2009	2010	2011
Cumulative Natural Gas Savings (m^3)	**Power Generation**	7,689,125	67,715,197	69,372,232	87,708,786
	Industrial	463,212,790	617,062,026	912,564,045	1,392,613,906
	Total	**470,901,915**	**684,777,223**	**981,936,277**	**1,480,322,692**
Projects Completed (1)	**Power Generation**	2	11	23	25
	Industrial	92	113	108	247
	Total	**94**	**124**	**131**	**272**

(1) Includes all studies, capital and O&M projects

The Program will build on Union's success in driving substantial energy savings and bill reductions for customers. Union is proposing to allocate $6.209 million in the large volume rate classes for DSM in 2013. This value includes the proposed Large Volume program budget, as well as the allocation of Board-approved DSM portfolio and Low-income costs allocated to Rate T1, Rate T2 and Rate 100 customers. The amount is consistent with 2012, escalated for inflation[2] and is allocated between Rate T1, Rate T2 and Rate 100 in Exhibit A, Tab 1, Schedule 1. Figure 1 displays the percentage allocation for each budget item included in the $6.209 million. The values for each budget item in Figure 1 are included in Tables 2 and 3 below.

[2] For 2013, Union has applied an illustrative inflation factor as at Q1, 2012 of 2.25%. The actual inflation rate applied for 2013 will be based on the four quarter rolling average of the Gross Domestic Product Implicit Index as at Q2 2012, released at the end of August.

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to receive customer incentives for projects and studies from the aggregate pool of budget available throughout the program year. This is consistent with Union's program approach in 2012 for these customers and the DSM program structure in Union's bundled contract rate classes that serve other similarly sized customers.

6.7 Program Duration

All Program offerings in the Large Volume Rate T1/Rate T2/Rate 100 Program will be delivered annually over the course of the two year DSM Plan. The offerings may change should market conditions change over the course of the Plan.

6.8 Cost Effectiveness

The estimated Total Resource Cost ("TRC") cost effectiveness for Union's Large Volume Rate T1/Rate T2/Rate 100 Program is displayed in Table 7. The actual cost effectiveness will be reported in Union's Annual Report for each program year.

Table 7: Large Volume Rate T1/Rate T2/Rate 100 Program Cost Effectiveness

Measure	Participants	Total TRC Benefits	Total TRC Costs	Total Net TRC Before Program Costs	TRC Ratio
Large Volume Offerings (Custom)[1]	41	$ 188,260,716	$ 22,056,635	166,204,080	8.5
Total		**$ 188,260,716**	**$ 22,056,635**	**$ 166,204,080**	
		Promotion Costs	$ 100,000		
		Administration Costs	$ 906,511		
		EM&V Costs	$ 40,000		
		Program Total Net TRC		**$ 165,157,569**	
		Program TRC Ratio			**8.1**

1. TRC Benefits and TRC Costs based on 3 year historical (2009-2011) average of Rate T1/Rate 100 custom results

With respect to Items 1 and 2, it is Union view, notwithstanding the principles of class ratemaking described above, that utility DSM programming continues to provide value for all customers. With the current low price of gas, DSM programming for all customers ensures that energy conservation remains a priority. Despite commodity price fluctuations, a sustained focus on energy-efficiency is important for the long-term environmental sustainability and economic competitiveness of Ontario. Payment of DSM funding ensures there is no internal competition for this budget for other uses within a customer's organization. It is a driver for large volume organizations to leverage ratepayer-funded technical support to seek out conservation opportunities within their facility. Union's proposed Direct Access program design incorporates the key elements of a self-direct program but has been tailored for Union's customers based on Union's knowledge of the market requirements and customer feedback. The proposed Plan, and in particular Union's proposals related to Direct Access, ensures that energy conservation continues to be a priority for large volume natural gas consumers in Ontario. Union further notes that in most jurisdictions where opt-out is a feature of a DSM plan, customers are required to demonstrate to the regulator that they are in fact undertaking DSM initiatives.

With respect to Item 3, the Guidelines and proposed Plan directly address the concerns related to the significant, unexpected, out-of-period adjustments possible under the DSM Plan ("Old Plan") in place prior to 2012.

Under the Old Plan, Union had no limit to the amount that could be spent in a rate class and the ability to increase DSM program spending by 15% of the total DSM budget. The additional 15% of available DSM program funds were not capped for any rate class. To the extent that DSM spending differed from the rate class allocation or Union accessed the additional funds, the variance was allocated to rate classes in the DSMVA in proportion to actual DSM spending by rate class. Since the amounts were not capped at the rate class level, this resulted in significant charges attributable to individual rate classes.

Although the Guidelines did not address these issues, the Agreement limited the following items: the overall Large Industrial program budget, the amount ($0.5 million) which may be transferred between large volume rate classes within this program budget, and the amount of the 15%

TAB 2

Environmental
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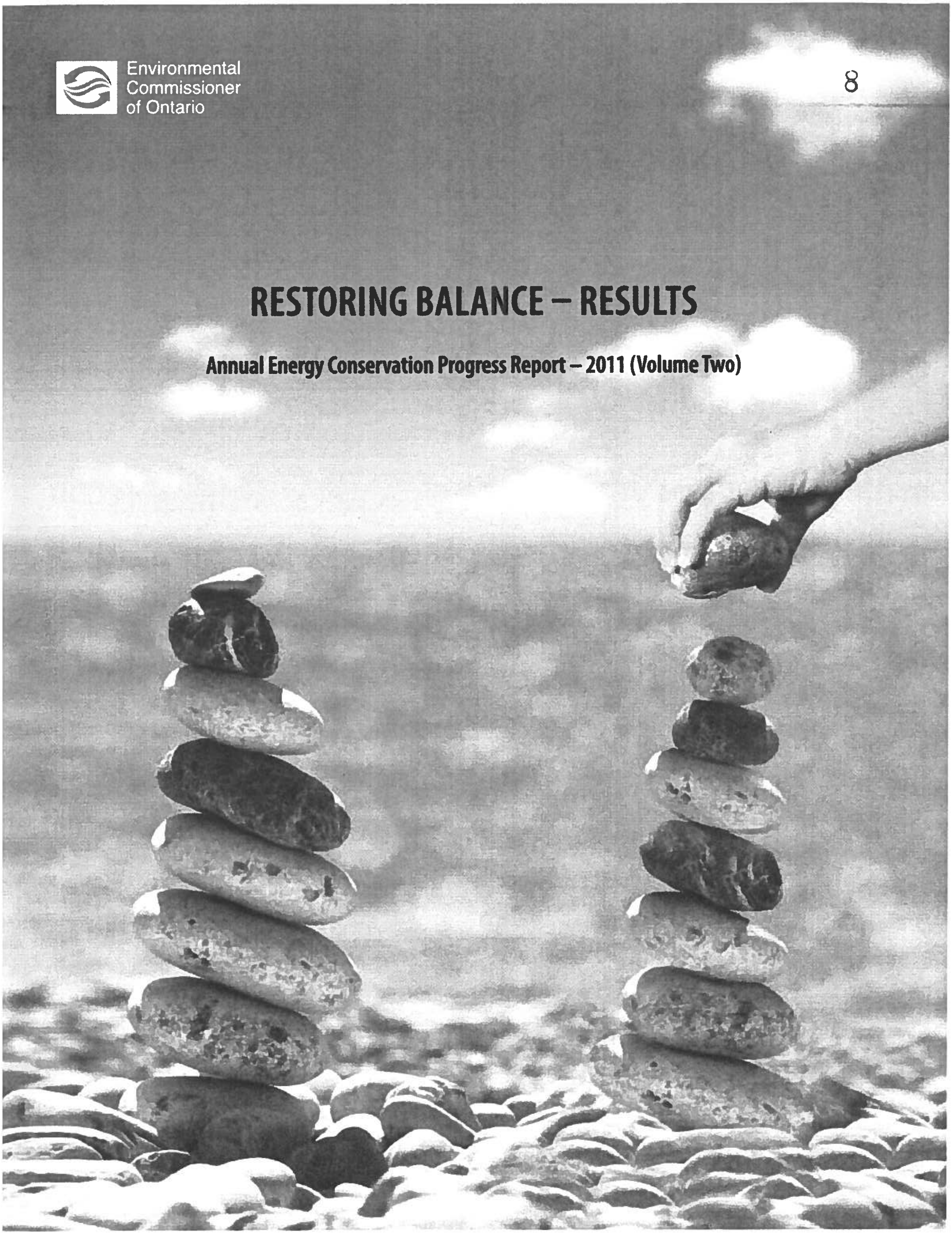
RESTORING BALANCE – RESULTS

Annual Energy Conservation Progress Report – 2011 (Volume Two)



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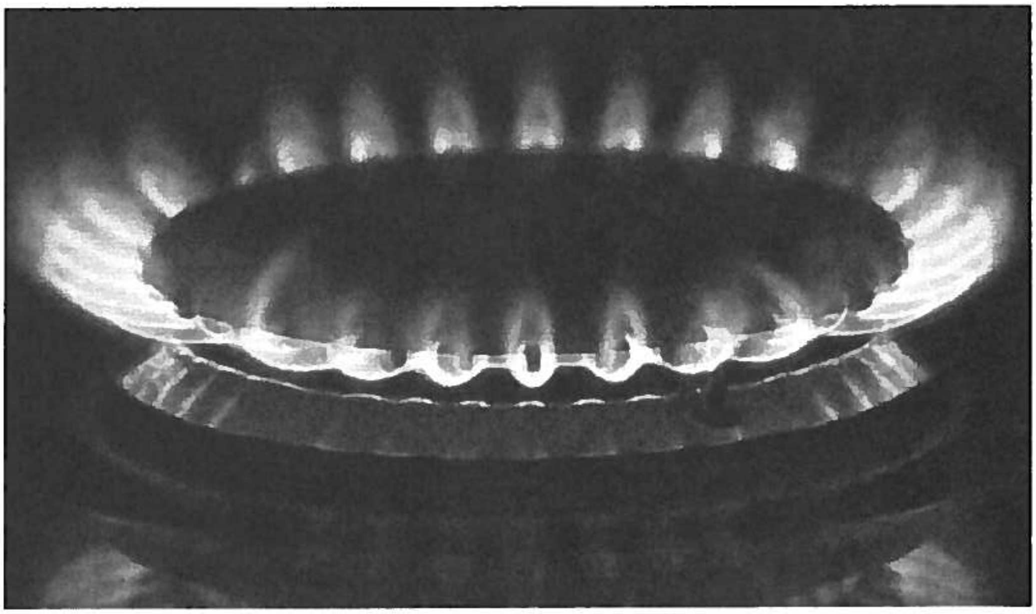
2.2 UPDATE ON NATURAL GAS UTILITY CONSERVATION TARGETS

The conservation programs offered by natural gas utilities (Enbridge Gas Distribution and Union Gas) in 2011 remained similar to those of previous years. Each utility has developed new conservation plans that will come into effect in 2012, reflecting changes to the Ontario Energy Board's Demand Side Management Guidelines that govern the utilities' conservation actions.

Both utilities easily exceeded their overall 2011 results targets, which are based on the net monetary savings that will be realized through conservation measures. The physical amount of natural gas saved by Enbridge's conservation measures has remained relatively flat over the past five years (approximately 77.3 million cubic metres [m^3] in 2011). In contrast, Union Gas has been able to take advantage of the opportunities for large savings among its industrial customers, and its gas savings have tripled between 2007 (55.9 million m^3) and 2011 (163.7 million m^3). Overall utility spending on gas conservation was approximately $55 million in 2011, a slight increase over recent years, but quite small in comparison to spending on electricity conservation ($270 million in 2011).



Both utilities also have conservation targets related to their market transformation program of installing drain water heat recovery systems in new residential construction. The percentage of new homes built with drain water heat recovery systems was much lower in Enbridge's service territory than in Union's in 2011 (9 per cent versus 21 per cent). Union Gas ended its incentives for drain water heat recovery at the end of 2011, noting that the energy savings from drain water heat recovery systems are lower than originally predicted. However, Enbridge will continue to offer an incentive for drain water heat recovery in 2012.

Finally, both utilities have a target specific to a low-income weatherization program that offers home audits and retrofits at no cost to low-income residents in selected geographic areas. The Ontario Energy Board's decision to allow utilities to access additional funding earmarked for low-income conservation permitted both utilities to more than double participation in the low-income weatherization program in 2011 relative to 2010.

For these reasons, the ECO believes that the original forecasts in the CDM strategies are of little value, and does not find it worthwhile to compare the actual 2011 results of each LDC against these forecasts. In the ECO's view, comparison of results achieved to date against the final targets is of more value.

Program Cost and Cost Effectiveness

Total electricity conservation spending in 2011 was $269.8 million dollars, including spending for OPA programs without LDC involvement.[56] This spending is recovered from all electricity ratepayers, through the Global Adjustment charge. With total Ontario electricity consumption of 141.5 TWh in 2011, this represents a charge of 0.19 cents (one-fifth of a penny) per kilowatt-hour on average. This represents about 2.5 per cent of the "electricity" charge on customer bills, and an even lower percentage if other charges such as delivery, regulatory charges and the Debt Retirement Charge are included.

A breakdown of spending for Tier 1 conservation programs by program and by type of cost is shown in Table 12. Approximately 80 per cent of funding went towards participant incentives.

Table 12: 2011 Province-Wide (Tier 1) Conservation Program Spending

Program	Central Program Services[1] ($)	Customer Incentives, Participant Based Funding, and Capability Building ($)	LDC Administration Costs ($)	Total Actual Charges ($)
Consumer Program	17,837,841	40,879,372	9,013,772	67,730,984
Business Program	5,693,241	115,269,033	12,046,822	133,009,095
Industrial Program	833,952	4,954,272	1,961,333	7,749,557
Home Assistance Program	13,165	0	457,911	471,076
Total – All Province-Wide (Tier 1) Programs	**24,378,199**	**161,102,677**	**23,479,837**	**208,960,712**

Note:

1. Central Program Services include: program delivery services, evaluation, measurement, verification, marketing, awareness campaigns, IT support, call centre, technical review services, and settlement services.

Source: Ontario Power Authority.

The cost effectiveness of 2011 conservation programs is shown in Table 13, using several different tests.[57] The Total Resource Cost test compares the lifetime program benefits (primarily due to avoided electricity, transmission, and distribution costs) with the program costs (e.g., administration and program delivery costs, along with any incremental cost of energy-efficient equipment) to all parties, including the program administrator and program participant.

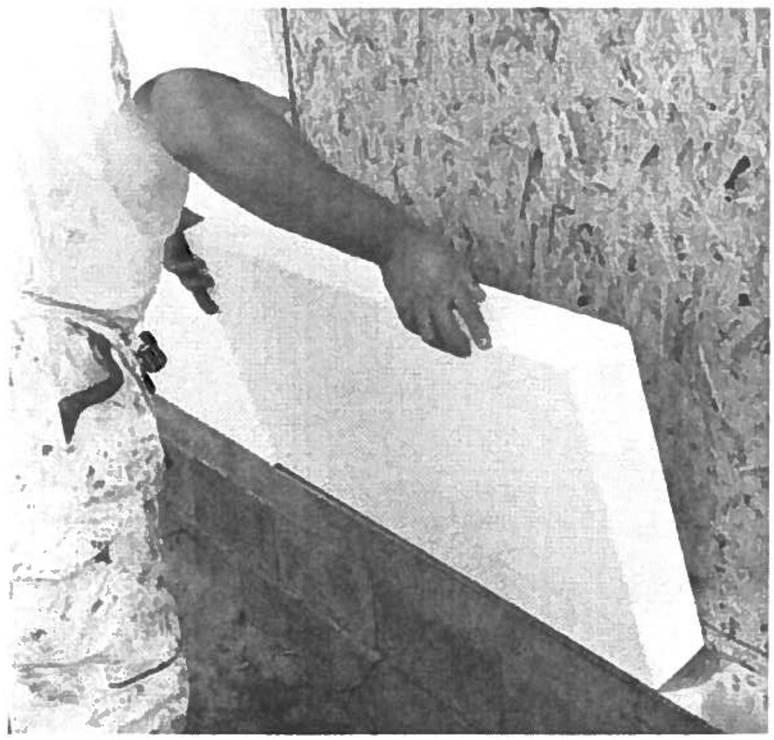
The Program Administrator Cost test compares the benefits and costs only from the perspective of the program administrator (i.e., the OPA). For both tests, a benefit:cost ratio greater than 1 means that the program benefits exceed the costs; the higher the ratio, the more desirable a program is. An ideal program scores highly on both tests. The OPA is required to ensure that its overall portfolio of Province-Wide programs is cost effective, although individual measures, initiatives and programs do not need to be cost effective. It should be noted that the OPA's cost-effectiveness tests currently assign no value to the environmental benefits of conservation, including the reduction in greenhouse gas emissions, thus undervaluing conservation from the ECO's point of view. By the ECO's calculation, the benefit of avoided greenhouse gas emissions from 2011 conservation program activities was at least $22 million dollars, assuming a value of $30 per tonne of avoided CO_2 emissions.[58]

Table 13: Cost Effectiveness of 2011 Province-Wide (Tier 1) Conservation Programs

Program	Total Resource Cost Test (benefit:cost ratio)	Program Administrator Cost Test (benefit:cost ratio)	Levelized Delivery Cost	
			Energy Efficiency (cents/kWh)	Demand Response (dollars/MW-month)
Consumer	1.46	2.34	3.85	9,653.86
Business	1.14	2.73	2.83	
Industrial (Demand Response 3 only)	2.98	0.93		11,103.09
Total – All Province-Wide (Tier 1) Programs	**1.23**	**2.52**	**3.07**	**10,179.00**

Note: Consumer program results also include commercial participants in Residential Demand Response initiative; Business program results also include industrial participants in Retrofit initiative.

Source: Ontario Power Authority.



As Table 13 shows, the portfolio of OPA programs was indeed cost effective in 2011 from the perspective of both tests. However, within this portfolio, not all initiatives have been cost effective (results at the initiative level are not shown in Table 13, with the exception of Demand Response 3). In particular, the *peaksaver* initiative (not *peaksaver* PLUS, which was not rolled out in 2011) has not been cost effective using either test. The Demand Response 3 initiative for larger industrial and commercial customers had a Program Administrator Cost test ratio less than 1, although this initiative is very effective from the perspective of the Total Resource Cost test.

The levelized delivery cost (also shown in Table 13) can be used to compare the cost of conservation with the cost of electricity supply, by calculating the average cost per unit of electricity saved (or produced). Each unit of electricity saved by the portfolio of 2011 energy efficiency programs cost ratepayers approximately 3 cents per kilowatt-hour, far less than the cost of any new source of supply. The levelized delivery cost for demand response programs is provided as the monthly cost per MW. The average of $10,179/MW-month for demand response programs compares favourably with an average of $13,187 for gas-fired generation.[59]

3.2.4 PROGRAM ISSUES

Operational Improvements

The OPA has attempted to work with LDCs to improve the effectiveness of Province-Wide programs. The primary vehicle for making improvements to conservation programs is the Change Management process. The OPA notes that substantial program improvements suggested by LDCs, based on their program delivery experiences, have been made through this process. In addition, an Expedited Change Management process has been developed, which will allow minor changes to programs to be made faster (reducing estimated time from 3-6 months down to 3-8 weeks). The Expedited Change Management process is expected to be available in fall 2012.

APPENDIX A: CURRENT ENERGY CONSUMPTION

Introduction

The ECO has chosen to examine energy consumption by fuel type in Ontario. This approach is taken because this office is responsible for reporting on the progress of government activities related to reducing or making more efficient use of electricity, natural gas, propane, oil and transportation fuels.

Like earlier ECO reports, this analysis relies on the energy consumption statistics contained in the Report on Energy Supply and Demand in Canada (RESD) and produced by Statistics Canada. Unlike earlier ECO reports, however, only preliminary data were available for the 2009 calendar year due to significant methodological changes for data surveys that supply information to the RESD.[100] Going forward, this office will use data from Statistics Canada that incorporate these methodological changes.

Analysis

According to the preliminary data for 2009, the total energy demand for Ontario was 2,374 petajoules (PJ). Figure 5 shows the breakdown of this energy demand by fuel type. Natural gas and transportation fuels accounted for about 73 per cent of the total energy used. Meanwhile, electricity accounted for 19 per cent of Ontario's overall energy demand. Propane, oil and other fuels accounted for roughly 8 per cent of Ontario's overall demand. This trend is virtually identical to what was observed in 2008 and 2007, as reported in previous years' ECO Annual Energy Conservation Progress Reports.

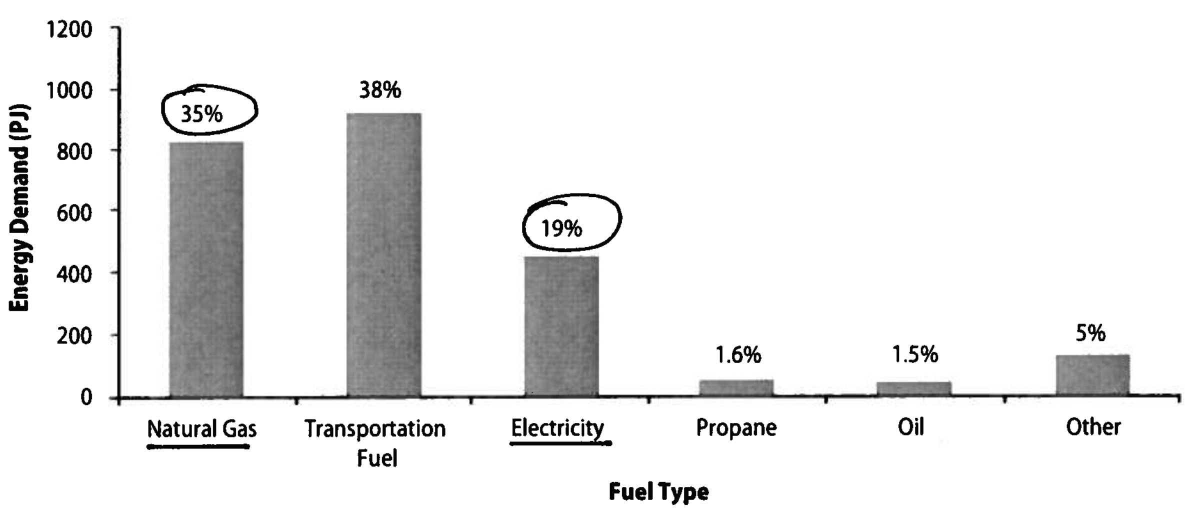


Figure 5: Ontario 2009 Total Final Energy Demand by Fuel Type

Notes:

Oil demand is based on kerosene, stove oil and light fuel oil amounts; Transportation Fuel is based on motor gasoline, diesel fuel oil, heavy fuel oil, aviation gasoline, and aviation turbo fuel amounts; details of Oil and Transportation Fuels come from Table 4-8 of Statistics Canada's 57-003-X report; Other fuel amount is based on Ontario's total final energy demand for 2009 (preliminary).

The information in this table should not be compared with information published in future ECO reports. After the 2009 preliminary data were released by Statistics Canada, significant methodological changes occurred (changes were made to improve data quality for the Annual Industrial Consumption of Energy survey, and a new survey – the Annual Survey of Secondary Distributors of Refined Petroleum – began in 2009). Next year's ECO report will incorporate these methodological changes.

Source: Statistics Canada – Catalogue no. 57-003-X *Report on Energy Supply and Demand in Canada – 2009 Preliminary.*

Table 16 provides numerical details for Figure 5, along with the demand values for 2007 and 2008 calendar years. For 2009, overall energy consumption in Ontario declined 7.4 per cent compared with 2008 levels. Statistics Canada attributes this decrease to declining energy demand in Ontario's manufacturing sector, although all sectors saw some reduction in energy demand.[101] To provide greater context for this decrease, across Canada there was an observed decline in energy consumption for the second consecutive year and a decrease in final demand occurred across all major sectors of the economy. At the national level, the greatest decrease came from the residential and agriculture sectors. In Ontario, the greatest decrease came from the industrial sector, where total industrial demand for primary and secondary energy fell 16 per cent, followed by the agriculture sector (9 per cent), residential sector (7 per cent),

TAB 3

CME Ontario

Advancing Opportunities in Energy Management in Ontario Industrial and Manufacturing Sector

Final Report

Submitted by:
Canadian Manufacturers & Exporters

In Association with:
Stantec Consulting, Marbek, and ODYNA

March 17, 2010

Revision 1

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Executive Summary

Background

Energy management (EM) is increasingly being recognized as an important core strategy to help sustain the productive sectors of our economy and reduce industry's negative impact on climate change. Canadian Manufacturers & Exporters (CME) is a long time and strong proponent of EM and retained Stantec Consulting and Marbek to conduct a study:

Advancing Opportunities in Energy Management in Ontario Industrial and Manufacturing Sector

The outcomes from this study fill critical knowledge gaps pertaining to EM potential in Ontario industry and provide the basis for public policy and program initiatives targeted to help Ontario industry increase its competitiveness and reduce greenhouse gas (GHG) and criteria air contaminant (CAC) emissions associated with energy use.

The primary objectives of the study are to: determine the ***current energy management performance*** of the industrial sector; estimate the ***economic potential*** for energy management, together with the associated greenhouse gas (GHG) and criteria air contaminants (CACs) emission reduction; benchmark the ***GHG and CAC emissions*** associated with energy use in Ontario's industrial sector; and develop a ***framework*** to accelerate the implementation of best practices and increase industry's EM performance.

This study focuses on the Ontario industrial and manufacturing sector and defines the sector by eleven sub-sectors. The comprehensive methodology employed in this study is unique in that it integrates two critical areas of EM analysis, which are more commonly addressed separately:

i) Energy management ***performance benchmarking***; and
ii) Energy management ***potentials analysis***.

EM performance benchmarking seeks to understand the relationship between the EM practices and the implementation of technical best practices. The EM potential scenario estimates the reduced amount of energy use compared to a Reference Case projection of energy use in Ontario industry from 2007 to 2030.

A total of 148 plants participated in the energy performance benchmarking portion of the study and data was obtained through remote surveys, on-site assessments and telephone interviews. In terms of participation, six sub-sectors are very well represented, while three sub-sectors have moderate representation and two sub-sectors have limited or no representation. To ensure representative data was used in the EM potential analysis, data from secondary sources were used to supplement sub-sectors with low or no representation.

Energy Use Profile

In 2007 Ontario's industrial sector used an estimated total 732 PJ[1] of energy; 640 PJ if biomass is excluded. Natural gas and electricity accounted for 38 percent and 22 percent of total energy use, respectively, while biomass accounted for an estimated 13 percent of total energy use. The ten largest sub-sectors, by total energy use, accounted for close to 85 percent of Ontario industrial energy use. Close to 65 percent of the energy was used by industry for process heating, while motive power and air compressors accounted for close to 15 percent.

The Reference Case total energy use is estimated to increase by about 16 percent from 2007 to 2030. In absolute terms the increase is close to 104 PJ. The largest increases in energy use are associated with four of the five largest sub-sectors, by energy use: Primary Metal; Chemical; Non-metallic Mineral Products; and Petroleum and Coal Products manufacturing. The Other Industry manufacturing sub-sector shows the largest decrease in energy use.

Implementation of Best Practices

The energy performance benchmarking results illustrate a relatively low implementation of *technical best practices* (TBPs) in the Ontario industrial sector. The 75th percentile of TBP implementation by sub-sector ranges from 31 to 42 percent. This means most of the plants have implemented less than 42 percent of applicable TBPs, and the opportunity exists for most companies to implement more than 58 percent of the TBPs. The end uses with the lowest levels of implemented TBPs are motive power, lighting, and cooling and refrigeration. Compressed air systems have the highest implementation of TBPs.

The implementation of TBP by plant size indicates large plants have implemented, on average, close to 10 percent more TBPs than small and medium sized enterprises (SME). The most significant differences in TBP implementation were observed for lighting, process specific, and indirect process heating (e.g. boilers and steam system) end uses.

Overall, 75 percent of plants have implemented less than 48 percent of the energy *management best practices* (MBPs). Among the sub-sectors, relatively low implementation of MBPs was observed in: Primary Metal manufacturing; Other manufacturing; and Fabricated Metal manufacturing. Higher implementation rates of MBPs were observed in: Chemical manufacturing; Non-metallic Mineral manufacturing; Transportation and Machinery manufacturing; and Food and Beverage manufacturing. These results indicate that, in general, plants manage and finance energy projects on an ad-hoc basis, while best practices associated with continuous improvement are not widely implemented. This is reflected by the categories with lowest implementation of MBPs: Policy and Planning; Organization and Accountability; Monitoring, Reporting and Communication; and Training and Capacity building.

The implementation of MBPs by plant size indicates that large plants have implemented, on average, close to 30 percent more MBPs than SMEs. The most significant differences in MBP implementation are observed in the Financing, Policy and Planning, and Monitoring categories.

The energy performance benchmarking results indicate that plants that have implemented more than 75 percent of the MBPs, on average have implemented 42 percent of the applicable

[1] 1 Peta-Joule (PJ) = 2.8×10^5 MWh

TBPs. Only five percent of all the plants fall into this top MBP quartile category. On the other hand, plants that have implemented less than 25 percent of the MBPs, on average, have implemented 25 percent of the applicable TBPs. Almost 50 percent of all the plants fall into this bottom quartile of the MBP category. These results illustrate the relationship of the degree of MBP implementation to that of TBP implementation, indicating that the implementation of the former encourages the implementation of the later, thus providing opportunities for energy savings.

Energy Management Potential and Associated Emission Reduction Potential

If all the remaining economically feasible best practices were implemented, total Ontario industrial energy use would be estimated to decrease from 2007 levels by 110 PJ in 2030. These savings would represent a 29 percent reduction in yearly energy use in 2030, as compared to the Reference Case energy use, which is the projected energy use without any new EM market interventions after 2007. The absolute energy savings would be larger for sub-sectors that account for the largest share of energy use, such as Primary Metal manufacturing and Chemical manufacturing, while lower absolute energy savings would be associated with sub-sectors that account for a smaller share of the total energy use, such as Fabricated Metal Products manufacturing and Plastics manufacturing.

Natural gas use is estimated to decrease by 106 PJ, over the Reference Case scenario natural gas use, in 2030. This is 50 percent of the total 2030 industry savings. The significant savings potential estimated for the direct (which includes ovens, dryers, kilns and furnaces) and indirect (which includes boilers and steam systems) process heating end uses are the main reason for the large natural gas savings potential. The system end use, which includes TBPs that apply to the total plant, is estimated to contribute over 35 percent of all the Economic Potential savings by 2030.

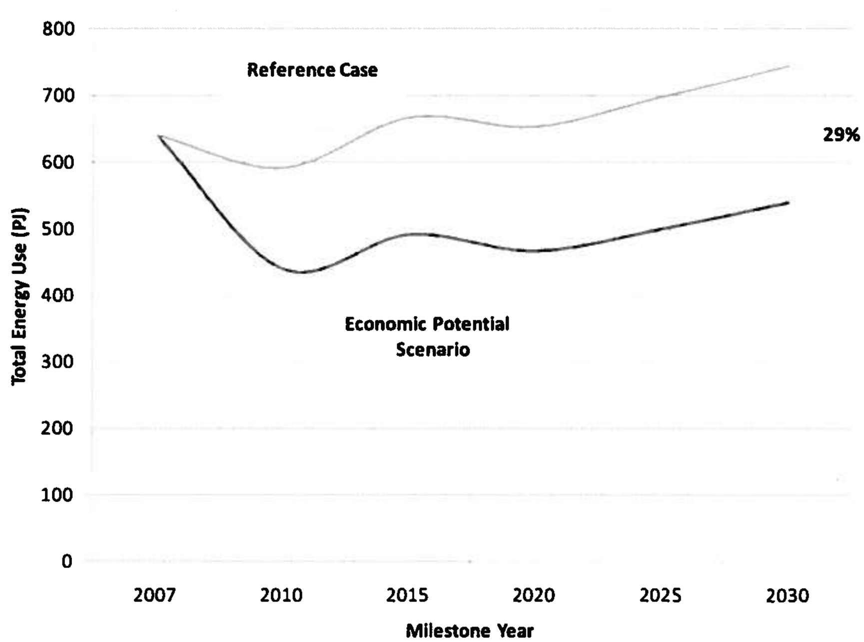
The 2007 Base Year greenhouse gas (GHG) emissions associated with energy use are 39.5 million tonnes CO_2eq and the associated criteria air contaminants (CAC) emissions are 92.9 tonnes. Due to the projected increase in energy use in the Reference Case it is estimated that the GHG emissions will increase by 16 percent and CAC emissions by 17 percent by 2030. If all the economically feasible energy efficiency best practices are implemented, as per the Economic Potential scenario, the reduction in GHG emissions is estimated to be 12.6 million tonnes CO_2eq (or 27 percent) less compared to the Reference Case in 2030. The Economic Potential scenario CAC emission reduction is estimated to be 27.5 tonnes (or 25 percent) compared to the Reference Case in 2030.

- The MBPs are applied as one bundle, referred to as 'Energy Management', to the system end use, which is the total plant energy use.
- Individual TBP savings are cascaded, with each TBP saving a percentage of the remaining energy in an end use.
- The absolute energy savings are calculated as the difference between the Reference case energy consumption and the Economic potential scenario energy consumption.

9.2 Economic Potential Scenario Energy Use

If all the economically feasible best practices are implemented, total Ontario industrial energy use is estimated to decrease by 110 PJ from 2007 to 2030. The estimated energy use in 2030 is 29 percent less than the energy use in the Reference Case, which is the projected energy use without any new EM market interventions after 2007, as discussed above in Section 6. The estimated energy use and savings by industry are illustrated in Exhibit 32, and summarized by sub-sector, fuel type and end use in Exhibit 33, Exhibit 34 and Exhibit 35. The detailed results are included in Appendix H.

Exhibit 32: Reference Case and Economic Potential Scenario energy use for all industry



The economic potential energy savings per sub-sector in 2030 range between 25 percent and 36 percent, compared to Reference Case energy use. The Fabricated Metal Products manufacturing shows the largest percentage Economic Potential savings at 36 percent compared to its own Reference Case energy use in 2030. The Chemical manufacturing sub-sector has the lowest percentage Economic Potential energy savings, at 25 percent. The Primary Metal manufacturing sub-sector has the second lowest percentage energy savings, at 27 percent, but accounts for the largest absolute amount energy savings at 53 PJ compared to its own Reference Case energy use in 2030. The absolute energy savings is larger for sub-sectors that account for the largest share of energy use, while lower absolute energy savings are associated with sub-sectors that account for a smaller share of the total energy use.

Exhibit 33: Reference Case and Economic Potential Scenario energy use by sub-sector (PJ)

Sub-sector	Base Year 2007	Reference Case 2030	Economic Potential 2030	2030 Economic Potential Savings PJ	%
Primary Metal Manufacturing	152	200	147	53	27%
Chemical Manufacturing	82	104	78	26	25%
Paper Manufacturing	62	64	45	19	30%
Non-metallic Mineral Product Mfg.	55	79	54	24	31%
Petroleum Refineries	54	74	52	23	30%
Transportation Equipment & Machinery Mfg.	45	41	28	13	32%
Food & Beverage Product Mfg.	37	33	23	10	31%
Mining (Excl. Oil & Gas)	33	35	26	10	27%
Fabricated Metal Product Mfg.	17	16	10	5.8	36%
Plastics Manufacturing	15	20	14	6.0	30%
Other Industry	87	78	53	24	31%
Total	**640**	**744**	**530**	**214**	**29%**

As discussed in Section 6, natural gas accounts for 43 percent of the total projected energy use in 2030, and contributes the largest amount of energy savings in the Economic Potential scenario at 2030. Natural gas is estimated to save 106 PJ in 2030 compared to the Reference Case scenario, which is 50 percent of the total 2030 industry savings. The significant savings potential estimated for the direct and indirect process heating end uses are the main reasons for the large natural gas savings potential. The system end use, which includes measures that apply to the total plant, is estimated to contribute over 35 percent of all the Economic Potential savings by 2030.

Exhibit 34: Reference Case and Economic Potential Scenario energy use by energy source (PJ)

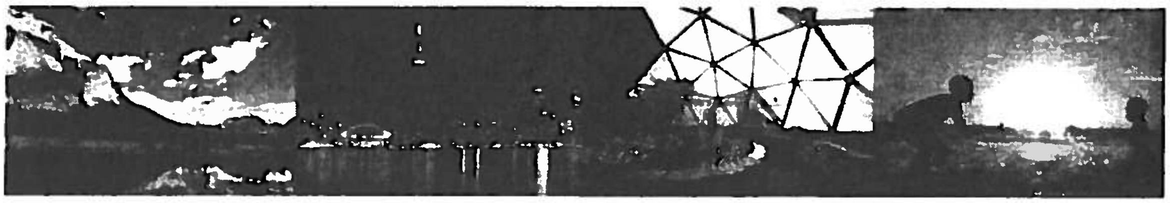
Energy Source	Base Year 2007	Reference Case 2030	Economic Potential 2030	2030 Economic Potential Savings PJ	%
Natural Gas	282	323	216	106	33%
Electricity	158	176	124	52.4	30%
RPP	62.5	91.4	68.7	22.7	25%
Other	137	154	121	32.7	21%
Totals	***640***	***744***	***530***	***214***	***29%***

TAB 4

Filed: 2011-09-23
EB-2011-0327
Exhibit A
Tab 1
Appendix K

ICF MARBEK NATURAL GAS ENERGY EFFICIENCY POTENTIAL STUDY

Marbek



Natural Gas Energy Efficiency Potential
Residential, Commercial and Industrial Sectors

Summary Report – Update 2011

Project
114103

Submitted to
Union Gas Distribution

Submitted by
ICF Marbek

July 2011

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5 Industrial Sector

The Industrial sector consists of the eight largest natural gas consuming industrial sub sectors within the Union service area plus an additional miscellaneous category that combines the remaining smaller industry groups. As applicable, each of the eight large industrial sub sectors was further divided into the very large "Contract" customers and the remaining "Other" sites. The large Contract customers, which are the primary focus of this study, are: Primary Metal, Chemical, Paper, Transportation and Machinery, Petroleum Refineries, Mining, Food and Beverage and Non-metallic Mineral.

5.1 Approach

The detailed end-use analysis of energy efficiency opportunities in the Industrial sector employed ICF Marbek's customized macro model. The model is organized by major industrial sub sector and major end use.

Natural gas end-use profiles were developed for the nine sub sectors described above. The profiles map proportionally how much natural gas is used by each of the end uses for each sub sector. These profiles represent the sub sector archetypes and are used in the model to calculate the natural gas used by each end use for each sub sector.

The major steps in the general approach to the study are outlined in Section 1.4 above (Approach). Specific procedures for the Industrial sector were as follows:

- **Modelling of Base Year:** The consultants compiled Base Year data on the industrial sector from a variety of sources, including Union's customer information, the study team's own energy assessment experience within many of the sub sectors and secondary data sources. The macro model results produced a close match with actual Union sales data.

- **Reference Case Calculations:** The consultants prepared a Reference Case forecast based on projected growth forecasts provided by Union, which includes anticipated closing of existing facilities and opening of new facilities.

- **Assessment of DSM Measures:** To estimate the economic and achievable natural gas savings potentials, the consultants assessed a wide range of commercially available energy efficiency measures and technologies such as:

  - Integrated control systems
  - More efficient boiler, steam and hot water systems
  - Efficient process heating technologies
  - Efficient space heating and ventilation, including solar thermal technologies.

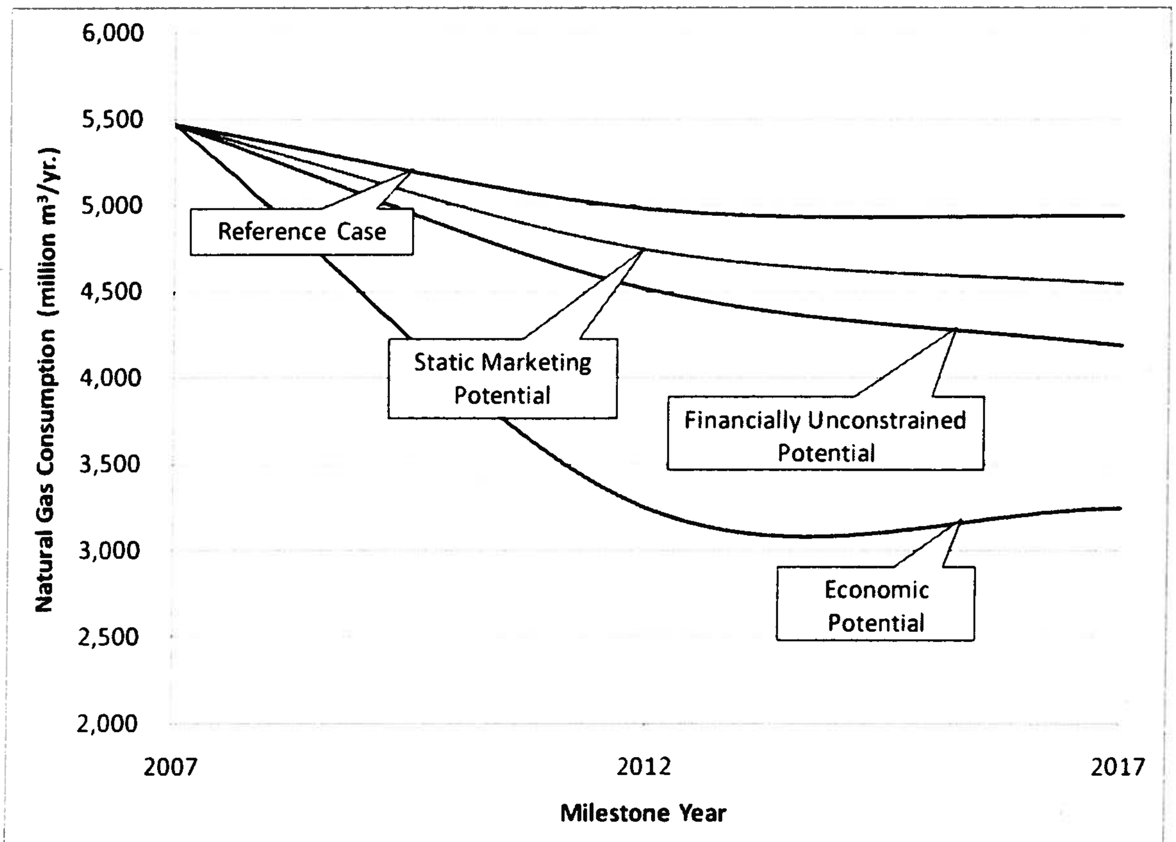
5.2 Industrial Natural Gas Savings Potential

A summary of the levels of annual natural gas consumption and potential natural gas savings contained in each of the Industrial sector forecasts addressed by the study is presented in Exhibit 23 and Exhibit 24, and is discussed briefly in the sub sections that follow.

Exhibit 23: Summary of Forecast Results for the Total Union Service Area Annual Natural Gas Consumption and Savings, by Milestone Year and Forecast Scenario, Industrial Sector

Milestone Year	Annual Consumption, Industrial Sector (million m^3/yr.)				Potential Annual Savings (million m^3/yr.)		
	Reference Case	Economic Potential	Achievable Potential: Financially Unconstrained	Achievable Potential: Static	Economic Potential	Achievable Potential: Financially Unconstrained	Achievable Potential: Static
2007	5,465						
2012	4,978	3,244	4,513	4,740	1,734	465	238
2017	4,937	3,242	4,189	4,541	1,695	749	396

Exhibit 24: Graphic of Forecast Results for the Total Union Service Area Annual Natural Gas Consumption and Savings by Milestone Year and Forecast Scenario, Industrial Sector



5.3 Base Year Natural Gas Use

In the Base Year of 2007, the Industrial sector in Union's total service area consumed about 5,465 million m^3 of natural gas. This volume excludes natural gas used for power generation, co-generation and industrial feedstock, as these uses of natural gas are beyond the scope of this study.

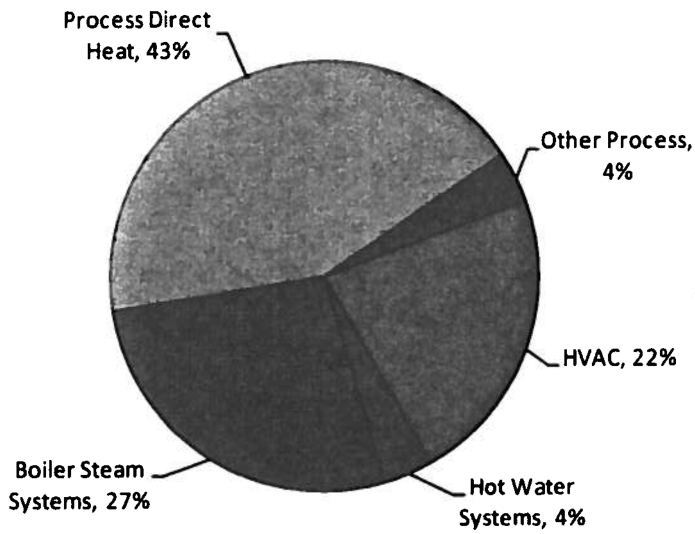
The twelve core industrial sub sectors (both contract and other customers), shown in Exhibit 25, account for 88% of the total industrial natural gas consumption. About 70% of the total industrial natural gas consumption occurs in the Southern service region.

Exhibit 25: Base Year Industrial Sector Natural Gas Consumption for the Total Union Service Area (1,000 m^3/yr.)

Sub Sector	End Use					Total	
	Hot Water Systems	Boiler Steam Systems	Process Direct Heat	Other Process	HVAC		
Contract Primary Metal	27,568	161,964	963,099	31,428	194,357	1,378,415	25%
Contract Chemical	20,117	408,369	331,925	74,222	171,201	1,005,834	18%
Other Chemical	741	15,034	12,220	2,732	6,303	37,030	0.7%
Contract Paper	11,344	353,887	107,431	10,380	84,175	567,218	10%
Contract Transportation and Machinery	7,827	91,046	117,313	15,868	159,278	391,332	7%
Other Transportation and Machinery	2,984	34,718	44,734	6,051	60,736	149,223	3%
Contract Petroleum Refineries	7,520	72,251	253,607	6,738	35,873	375,989	7%
Contract Mining	64,023	80,029	112,041	16,006	48,017	320,117	6%
Other Mining	4.9	6.1	8.6	1.2	3.7	25	0.0004%
Contract Food and Beverage	20,142	120,397	69,212	15,585	26,436	251,771	5%
Other Food and Beverage	4,463	26,680	15,337	3,454	5,858	55,793	1%
Contract Non-Metallic Mineral	5,598	33,477	198,345	10,581	31,910	279,911	5%
Miscellaneous Industrial	33,945	75,984	127,031	17,690	398,131	652,781	12%
Total	206,277	1,473,842	2,352,303	210,736	1,222,280	5,465,438	
%	4%	27%	43%	4%	22%		

As illustrated in Exhibit 26, process direct heat accounts for about 43% of total industrial sector natural gas use in the base year. Boiler steam systems account for about 27% of the total natural gas use, followed by heating, ventilation and air conditioning (HVAC), which accounts for about 22%. Other processes and hot water systems account for the remaining natural gas consumption.

Exhibit 26: Base Year Industrial Sector Natural Gas Use for the Total Union Service Area, by End Use



5.4 Reference Case

In the absence of new DSM initiatives, the study estimates that natural gas consumption in the Industrial sector will decrease from 5,465 million m^3/yr. in 2007 to about 4,937 million m^3/yr. by 2017. This represents an overall decrease of about 9.7% in the period and compares very closely with Union's own forecast, which also includes consideration of the impacts of "natural conservation".

Exhibit 27 shows the forecast levels of Industrial sector natural gas consumption for the Union service area. The results are presented for each milestone year, service region and sub sector.

Exhibit 27: Industrial Sector Reference Case Natural Gas Use for the Total Union Service Area, by Sub Sector and Milestone Year (1000 m^3/yr.)

Sub Sector	Northern Region			Southern Region			All Regions		
	2007	2012	2017	2007	2012	2017	2007	2012	2017
Contract Primary Metal	398,032	461,065	467,735	980,383	1,011,357	1,010,852	1,378,415	1,472,422	1,478,587
Contract Chemical	256,247	214,125	211,763	749,587	675,774	621,166	1,005,834	889,900	832,929
Other Chemical	2,310	1,930	1,909	34,720	31,301	28,772	37,030	33,231	30,681
Contract Paper	537,762	202,027	179,666	29,456	28,632	28,632	567,218	230,660	208,298
Contract Transportation and Machinery	10,593	10,582	10,582	380,739	181,276	181,276	391,332	191,858	191,858
Other Transportation and Machinery	1,411	1,410	1,410	147,811	70,375	70,375	149,223	71,785	71,785
Contract Petroleum Refineries	-	-	-	375,989	587,605	587,605	375,989	587,605	587,605
Contract Mining	307,752	229,235	223,060	12,365	11,791	11,791	320,117	241,026	234,851
Other Mining	-	-	-	25	23	23	25	23	23
Contract Food and Beverage	39,603	74,402	75,460	212,168	240,232	241,044	251,771	314,634	316,504
Other Food and Beverage	2,527	4,747	4,815	53,266	60,311	60,515	55,793	65,058	65,330
Contract Non-Metallic Mineral	21,239	20,799	20,799	258,672	97,129	97,129	279,911	117,928	117,928
Miscellaneous Industrial	76,363	37,532	37,532	576,418	724,392	763,575	652,781	761,924	801,107
Total	1,653,839	1,257,855	1,234,730	3,811,599	3,720,200	3,702,756	5,465,438	4,978,056	4,937,486

5.5 Economic Potential Forecast

Under the conditions of the Economic Potential Forecast[8], the study estimated that natural gas consumption in the Industrial sector would decline to about 3,242 million m^3/yr. by 2017 for the total Union service area. Annual savings relative to the Reference Case are about 1,695 m^3/yr. by 2017, or about 34%.

5.6 Achievable Potential

The Achievable Potential is the proportion of the economic natural gas savings (as noted above) that could realistically be achieved within the study period. In the Industrial sector, the Achievable Potential for natural savings through technology adoption by 2017 was estimated to be 749 million m^3/yr. and 396 million m^3/yr., for the Financially Unconstrained and Static Marketing scenarios, respectively. These savings represent about 44% and 23% of the savings identified in the Economic Potential Forecast.

5.7 Key Changes from 2008 Study

As part of the update process described in Section 1, ICF Marbek and Union Gas staff engaged in an iterative process to update the reference case to 2017. The 2017 achievable potential market penetration rates and their associated implementation curves were also updated. Updates were made for both the financially unconstrained and the static achievable potential scenarios. Exhibit 28 shows a comparison of the original and updated reference cases.

Exhibit 28: Summary of Changes to Natural Gas Consumption in the Reference Case, Total Residential Sector

Milestone Year	Original Reference Case	Updated Reference Case	Difference
		million m^3/year	
2007	5,465	5,465	-
2012	5,458	4,978	-480
2017	5,598	4,937	-661

The changes to the reference case, achievable participation rates, and adoption curves described above resulted in changes to savings in the static and financially unconstrained scenarios, as shown in Exhibit 29 and Exhibit 30, respectively.

[8] The level of natural gas consumption that would occur if all equipment was upgraded to the level that is cost-effective. In this study, "cost-effective" means that the technology upgrade passes the measure Total Resource Cost (TRC) test, as discussed previously in Section 1.3.

Exhibit 29: Summary of Changes to Natural Gas Savings in the Static Achievable Potential Scenario, Total Industrial Sector

Milestone Year	Original Savings	Updated Savings	Difference
		thousand m^3/year	
2012	317,576	237,689	-79,887
2017	524,337	396,498	-127,839
% Savings relative to Reference Case, 2017	9.4%	8.0%	-1.3%

Exhibit 30: Summary of Changes to Natural Gas Savings in the Financially Unconstrained Achievable Potential Scenario, Total Industrial Sector

Milestone Year	Original Savings	Updated Savings	Difference
		thousand m^3/year	
2012	557,106	465,417	-91,689
2017	846,175	748,869	-97,305
% Savings relative to Reference Case, 2017	15.1%	15.2%	0.05%

Compared to the original (2008) results, key differences in the updated study results include:

- The updates resulted in a lower reference case consumption and slightly lower potential savings in both the static and financially unconstrained scenarios.
- Updated savings are lower in all end uses, but the reduction is greatest in the Boiler Steam System and Other Process end uses.
- Updated savings are lower in all sub sectors, except the Contract Petroleum Refineries, Contract Food and Beverage, Other Food and Beverage, and Miscellaneous Industrial sub sectors. The greatest decrease in savings occurs in the Contract Non-Metallic Mineral sub sector.

5.8 Additional Observations

In addition to the preceding conclusions, three additional observations warrant note as they may affect future program strategies. They include:

- ***Rate of measure implementation has a large effect on overall savings.*** For measures that pass the TRC screen on an incremental cost basis, low participation rates in early milestone years create a significant "lost opportunity." This is particularly relevant to the replacement of equipment with a very long life, which is applicable to most industrial technologies and measures. The gap between Economic Potential and Achievable Potential savings presented in this study is due in large part to this significant lost opportunity that occurs in early milestone years.

- ***Bundling of measures to develop program concepts has an impact on the achievable potential results.*** To model the achievable potential scenario measures were grouped into bundles that were manageable within the scope and budget of the project. The results provide an indication of savings potential based on the specific set of measures included in the bundles. In defining specific programs it will be important to interpret the Achievable Potential savings potential by assessing individual measures within the context of the Economic Potential and the measure TRC results.

TAB 5

A QUESTION OF COMMITMENT

Review of the Ontario Government's Climate Change Action Plan Results

Annual Greenhouse Gas Progress Report 2012

Environmental Commissioner of Ontario

December 2012

Environmental Commissioner of Ontario

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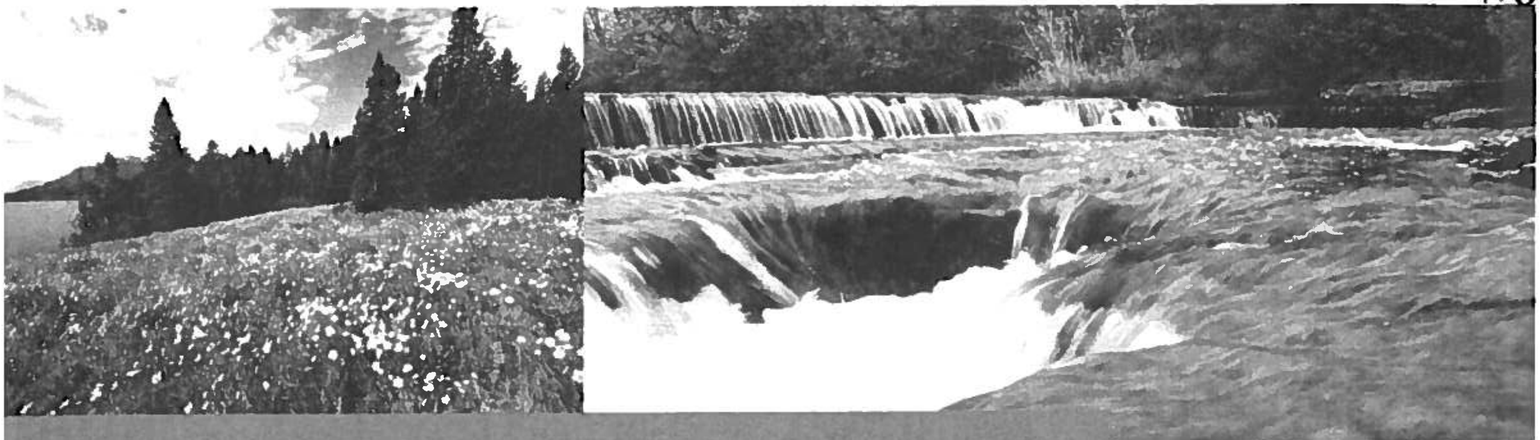


The long-term concentration of CO_2 in the atmosphere must be reduced to no more than 350 ppm if global climate conditions, similar to those in which our ecosystems and our civilization have evolved, are to be maintained.

Targets

In 2007, the government released Go Green: Ontario's Action Plan on Climate Change ("Climate Change Action Plan"), which established three GHG emissions reduction targets:[3]

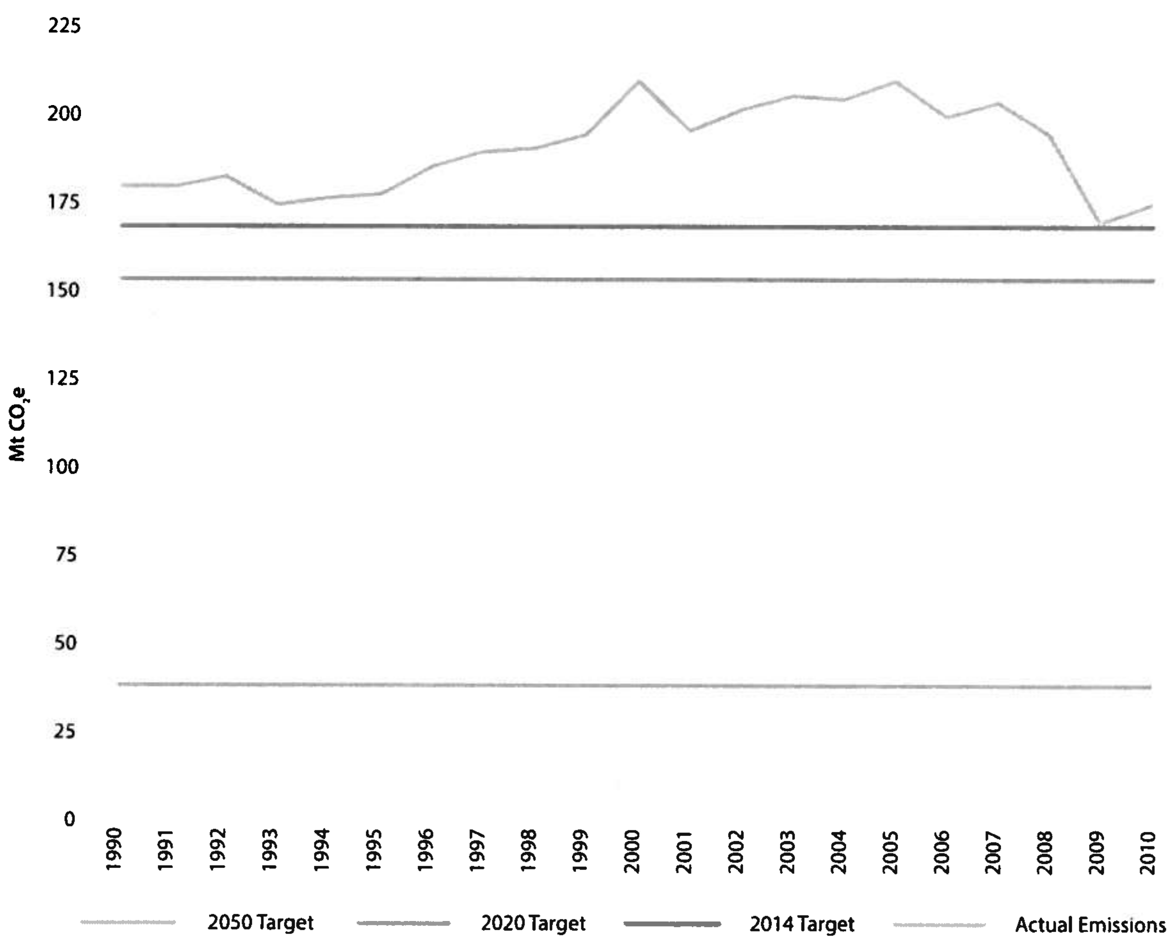
- 6 per cent below 1990 levels by 2014 (to approximately 165 megatonnes or Mt);
- 15 per cent below 1990 levels by 2020 (to approximately 150 Mt); and
- 80 per cent below 1990 levels by 2050 (to approximately 35 Mt).

These targets are based on the internationally agreed-upon goal of limiting the increase in global average temperatures to 2°C above pre-industrial levels. In order to have a reasonable chance of preventing temperatures from exceeding this amount, the Intergovernmental Panel on Climate Change recommended in 2007 that the concentration of GHGs in the atmosphere would have to be stabilized at, or below, 450 ppm. More recent analysis of paleoclimatic data has led James Hansen, head of the NASA Goddard Institute for Space Studies, to conclude that the long-term concentration of CO_2 in the atmosphere must be reduced to no more than 350 ppm if global climate conditions, similar to those in which our ecosystems and our civilization have evolved, are to be maintained. Unfortunately, the Ontario action plan and targets have not been adjusted to reflect this new understanding of the climate system.

Progress Toward the Targets

In 2010, Ontario's emissions of 171 Mt were 3 per cent below the 1990 base year level (176 Mt). Figure 1 tracks Ontario's emissions over the past 20 years against the targets in the Climate Change Action Plan.

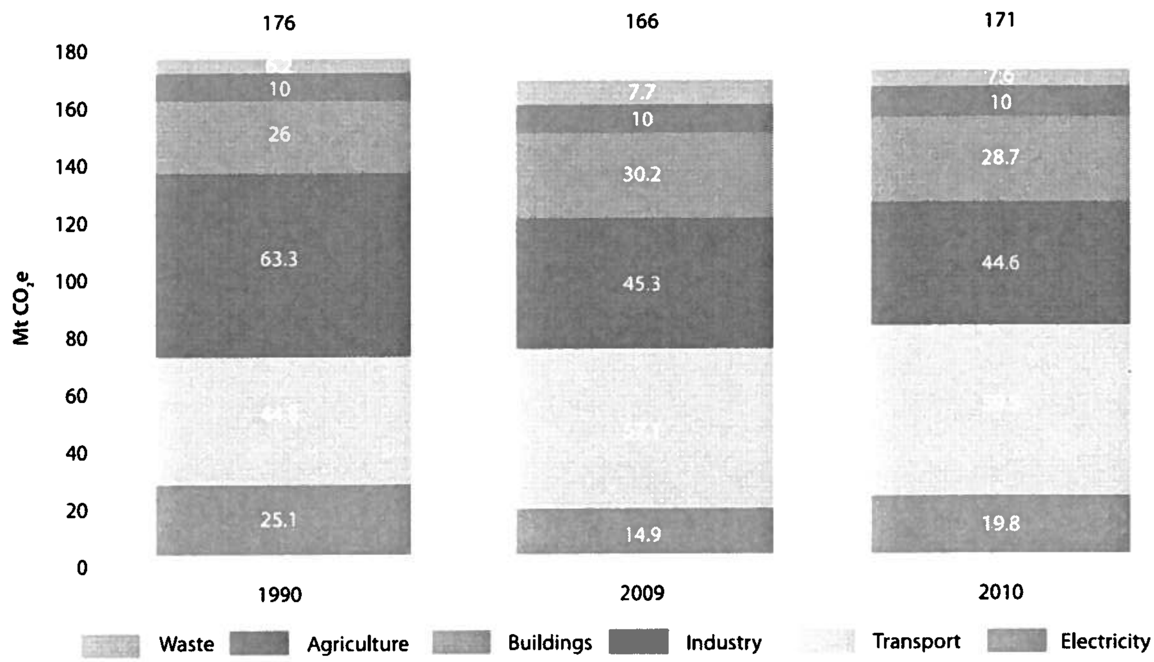
Figure 1: Actual Emissions versus Climate Change Action Plan Targets



Source: Environment Canada. (2012). *National Inventory Report – Greenhouse Gas Sources and Sinks in Canada 1990–2010.* Part 3, p. 61. Government of Ontario (2007). Go Green: Ontario's Action Plan on Climate Change.

While some sectors (such as electricity and industry) have experienced an overall decline since 1990, others (such as transportation) have witnessed an equally significant increase (Figure 2). In 2010, similar to previous years, the transportation sector was responsible for the largest volume of emissions, followed by industry and buildings.

Figure 2: Emissions by Sector, 1990, 2009 and 2010 in Megatonnes



Source: Environment Canada. (2012). *National Inventory Report – Greenhouse Gas Sources and Sinks in Canada 1990–2010.* Part 3, p. 61.

The Ontario government indicates that progress has been made toward meeting the 2014 and 2020 targets, primarily by phasing out the use of coal for electricity generation. The coal phase-out is a significant commitment that, on its own, takes Ontario most of the way toward meeting the 2014 target and at least halfway toward the 2020 target. Unfortunately, the ambition displayed in the electricity sector has not been matched in other areas over the past year, and the Ontario government will not reach its 2020 emissions target without additional policy action. The government, itself, has projected a 30 Mt gap by 2020, an amount that is almost equal to what will have been achieved through coal phase-out.

TAB 6

Table of Ontario's Natural Gas-Related & Other Greenhouse Gas ("GHG") Emissions in 2010

Percent of Ontario's Total 2010 Energy-Related GHG Emissions from Certain Sources		
#	GHG Emission Source	Percent
1	Natural Gas Power Plants	8%
2	All Natural Gas Consumption	34.5%
3	Coal-Fired Power Plants	9%
4	Transportation	45.6%

Sources and Calculations

1. Ontario's total natural gas consumption in 2010 was 24,264.58 million cubic metres.[1]

2. Emission Factors for Natural Gas[2]:

   a) Carbon Dioxide: 1879 g/cubic metre
   b) Methane: 0.037 g/cubic metre
   c) Nitrous Oxide: 0.033 g/cubic metre

3. Natural Gas Consumption Emissions (m3 of gas multiplied by emission factors)

   a) Carbon Dioxide: 45,593,145.82 tonnes
   b) Methane: 897.79 tonnes
   c) Nitrous Oxide: 800.73 tonnes

4. IPCC Global Warming Potentials – 100 – Year Time Horizon (Second Assessment Report)[3]

   a) Carbon Dioxide: 1
   b) Methane: 21
   c) Nitrous Oxide: 310

5. Natural Gas Consumption GHG Emissions (Carbon Dioxide Equivalent)

   a) Carbon Dioxide: 45,593,145.82 tonnes
   b) Methane: 18,853.59 tonnes

[1] Statistics Canada, Catalogue 57-601, *Energy Statistics Handbook*, Tables 6.6 & 6.7, http://www.statcan.gc.ca/pub/57-601-x/2012001/tablelist-listetableaux6-eng.htm.
[2] Environment Canada, *GHG Emissions Quantification Guidance: Fuel Combustion*, http://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=AC2B7641-1.
[3] Environment Canada, *Global Warming Potentials*, http://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=CAD07259-1.

c) Nitrous Oxide: 248,226.3 tonnes
d) Total 45,860,225.71 tonnes

6. Ontario's Natural Gas Consumption GHG Emissions (45,860,225.71 tonnes) as a percent of Ontario's Total Energy-Related GHG Emissions (133,000,000 tonnes):

   34.5%[4]

7. Ontario's transportation-related GHG emissions as a percent of Ontario's Total Energy-Related GHG Emissions in 2010:

   45.6%[5]

8. Ontario's coal-fired electricity-related GHG emissions as a percent of Ontario's Total Energy-Related GHG emissions in 2010:

   9%[6]

9. Ontario's natural gas-fired electricity-related GHG emissions as a percent of Ontario's Total Energy-Related GHG emissions in 2010:

   8%[7]

   These emissions are a sub-component of Ontario's total Natural Gas Consumption GHG emissions.

---

[4] Calculated as 45,860,225.71 divided by 133,000,000. Ontario's total energy-related GHG emissions in 2010 were 133,000,000 tonnes. Environment Canada, *National Inventory Report 1990-2010 Part 3*, Table A14-12.
[5] Environment Canada, National Inventory Report 1990-2010 Part 3, Table A14-12.
[6] Environment Canada, National Inventory Report 1990-2010 Part 3, Table A14-12; and Environmental Commissioner of Ontario, *A Question of Commitment: Annual Greenhouse Gas Progress Report 2012*, (December 2012), page 21.
[7] Environment Canada, National Inventory Report 1990-2010 Part 3, Table A14-12; and Environmental Commissioner of Ontario, *A Question of Commitment: Annual Greenhouse Gas Progress Report 2012*, (December 2012), page 21.

Related GHG Figures

Ontario's GHG Emission Reduction Targets[8]

1. 6% below 1990 levels by 2014 (to approximately 165 megatonnes or Mt);
2. 15% below 1990 levels by 2020 (to approximately 150 Mt); and
3. 80% below 1990 levels by 2050 (to approximately 35 Mt).

GHG Emissions Gap

According to the Government of Ontario, in the absence of additional policy action, Ontario's GHG emissions in 2020 will be 30 Mt greater than its target.[9]

[8] Environmental Commissioner of Ontario, *A Question of Commitment: Annual Greenhouse Gas Progress Report 2012*, page 12.
[9] Environmental Commissioner of Ontario, *A Question of Commitment: Annual Greenhouse Gas Progress Report 2012*, page 14.

TAB 7

Ontario

DEMAND SIDE MANAGEMENT GUIDELINES FOR NATURAL GAS UTILITIES

EB-2008-0346

Date: June 30, 2011

The spillover effects are associated with customers that adopt energy efficiency measures because they are influenced by a utility's program-related information and marketing efforts, but do not actually participate in the program. Accordingly, there are no Program Costs associated with the spillover effects.[11] If the spillover effects are considered and adequately supported (see section 7.1 for details), then programs that have high spillover rates will be more cost effective (as measured by the TRC test) since they do not have Program Costs while they do generate benefits.

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

5.1.3 TRC Test Calculation

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

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

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

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

If the ratio of the PV of benefits to the PV of the costs (the "TRC ratio") exceeds 1.0, the DSM program is considered cost effective from a societal perspective as it implies that the benefits exceed the costs. If, on the contrary, the TRC ratio for a program falls below 1.0, the program would be screened out and no longer considered for inclusion as part of the DSM portfolio.[12]

The TRC threshold test should be 1.0 for all programs amenable to this screening test, except for low-income programs. To recognize that low-income natural gas DSM programs may result in important benefits not captured by the TRC test, these programs should be screened using a lower threshold value of 0.70 instead.[13]

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

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

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

projects and commercial and industrial DSM programs in general and provide the resulting information to and consult with their stakeholders to determine whether any persistence adjustments to the savings of those programs would be warranted going forward.

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

8. BUDGETS

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

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

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

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

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

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

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

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

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

8.1 Budget for Resource Acquisition Programs

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

8.2 Budget for Large Industrial Programs

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

8.3 Budget for Low-Income Programs

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

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

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

TAB 8

Court File No. 221/11

ONTARIO
SUPERIOR COURT OF JUSTICE
(Divisional Court)

BETWEEN:

POLLUTION PROBE FOUNDATION

Applicant

- and -

ONTARIO ENERGY BOARD

Respondent

AFFIDAVIT OF MICHAEL MILLAR
(affirmed March 15, 2012)

I, Michael Millar, of the city of Toronto, AFFIRM:

Introduction

1. I am an employee of the Ontario Energy Board (the "Board"), where I have been employed as legal counsel since 2004. I have acted as counsel for Board staff on numerous matters before the Board, including some of the matters at issue in this judicial review. I thus have knowledge of the matters hereafter deposed to, and I hereby declare that I verily believe that all of the information referred to herein is true.

2. I am authorized by the Board to make this affidavit on behalf of the Board in response to this application for judicial review, and in support of a motion by the Board to quash this application, and for no other or improper purpose. In authorizing me to make this affidavit, the Board does not waive any privilege in respect of any advice or communication made to the Board, whether involving myself or others.

3. I have read the Affidavit of Jack Gibbons herein, sworn on February 3, 2012 ("Gibbons Affidavit"). Without in any way accepting or adopting the commentary, characterizations, arguments and conclusions in the Gibbons Affidavit, and particularly those in paragraphs 3 (first sentence), 4, 11 (last sentence), 15, 16 (second

sentence), 21 (second sentence) and 26 thereof, the Board does accept that the documents and excerpts from documents referred to and marked as Exhibits therein are documents or excerpts of documents filed with the Board or exchanged between parties to the proceedings referred to. Clean copies of those documents are contained in the electronic "record" filed by the Board herein, or are attached hereto as Exhibits.

Prior Demand Side Management Hearings

4. In simple terms, Demand Side Management ("DSM") programs considered in this Application are programs that are designed to reduce the consumption of gas by consumers, and hence reduce the overall demand for gas consumption. These programs therefore reduce the amount of gas sold by gas distributers that are regulated by the Board, resulting in the environmental and other benefits referred to by the Applicant. As a result, since those gas distributers obviously have no economic incentive to pay for such programs, a key feature of Board regulation in this area is to ensure that the costs of these programs are recovered by distributors from gas consumers through the rates they pay for gas distribution. However, different consumers or classes of consumers benefit from different DSM programs, because take-up of the programs by consumers is not uniform. Therefore, another important policy interest of the Board's regulation in this area concerns issues of fairness, within and between consumers and consumer groups, and the cross-subsidization that results from these programs.

5. As noted by the Applicant, the Board has held prior proceedings in 1991-1993 (Board File No. E.B.O. 169) and in 2006 (EB-2006-0021). Those proceedings resulted in the issuance by the Board of binding instruments that have governed the development and approval of distributers' DSM plans and programs since 1993. Clean and complete copies of relevant documents from those proceedings (two of which are referred to in the Gibbons Affidavit) are included on the CD-ROM which is attached, together with an Index of its contents, as Exhibit "A" to this Affidavit.

DSM Plan Approval Hearings Since This Application was Commenced

6. Since the issuance by the Board of its "Demand Side Management Guidelines for Natural Gas Utilities" dated June 30, 2011 (the "DSM Guidelines") that are challenged by the Applicant in this proceeding for judicial review, both Union Gas Ltd. ("Union") and Enbridge Gas Distribution Inc. ("Enbridge") have filed rate applications with the Board, in which each of them sought approval for their respective DSM plans. The Board has now received all relevant filings and interventions, conducted hearings, and issued decisions and orders for both of these applications as follows.

The Union Application

7. Under Board file number EB-2011-0327, Union filed its application for approval of a 3 year DSM plan on September 23, 2011. A notice of hearing was issued at the Board's direction on October 13, 2011. A variety of interested parties, including the Applicant herein, intervened in the proceeding.

8. Through various procedural orders, the Board established a process for setting a final issues list, the filing of written interrogatories to test Union's evidence, and for holding a settlement conference. There were 26 issues and sub-issues on the final issues list. Thirteen intervenors (including the Applicant herein) participated with Union in the settlement conference.

9. The settlement conference resulted in no agreement on 2 of the 26 issues; a complete agreement amongst all parties, including the Applicant herein on 21 of the remaining 24 issues; and a "partial settlement" on three issues, involving complete agreement amongst all parties with the exception of the Applicant herein, which was opposed to the settlement reached by the other parties on those three issues. With the exception of the Applicant, all parties agreed that the 24 partially settled issues were "non-severable".

10. The Applicant herein objected to the non-severability clause, and asked the Board to not accept that portion of the settlement agreement. The "non-severable" clause

provided that if the Board rejected any element of the settlement agreement the entire settlement agreement would collapse and there would be no agreement on any issues. After hearing argument from parties on the matter, the Board rejected the Applicant's position in a decision dated February 8, 2012. That decision also included the Board's decision on the two unsettled issues, for which it had previously heard argument.

11. The Board subsequently held an oral hearing to hear the Applicant's objections to the three "partially settled" issues. Union called a witness to address the matters, who was cross examined by the Applicant. The Board then heard argument from the parties on the three partially settled issues. In a decision dated February 21, 2012, the Board accepted the entire settlement agreement, including the three partially settled issues that had been objected to by the Applicant herein.

12. Relevant documents from the EB-2011-0327 proceeding are included in a CD-ROM attached as Exhibit "A" to this Affidavit.

The Enbridge Application

13. Enbridge filed its rate application, including a request for approval of a DSM plan on November 4, 2011. The Board assigned the application file number EB-2011-0295. A notice was issued at the Board's direction on November 16, 2011. A variety of interested parties, including the Applicant, intervened.

14. Prior to filing its application, Enbridge had entered into negotiations with many of the parties who intervened in the case. As a result, Enbridge was able to file a settlement agreement with its application. The settlement agreement encompassed all DSM issues relevant to the 2012 rate year, except for two issues for which there was no agreement. Twelve intervenors (including the Applicant) were parties to the settlement agreement with Enbridge. Unlike in the Union proceeding, there were no "partially settled" issues. There was a complete settlement on all but two issues, for which two issues there was no agreement at all. Five intervenors had not participated in the settlement agreement.

15. On February 2, 2012, the Board held an oral hearing to hear both the settlement agreement and the unsettled issues. No party objected to the settlement agreement (including the five intervenors that had not been signatories to the agreement), and the Board approved the settlement agreement. The Board also heard submissions on the two unsettled issues, and issued a decision on these issues on February 9, 2012.

16. Relevant documents from the EB-2011-0295 proceeding is included in a CD-ROM attached as Exhibit "A" to this affidavit.

The Board's use of Guidelines

17. The use of non-binding guidelines to inform and structure proceedings before the Board is not uncommon. Non-binding guidelines assist both parties and the Board in navigating a busy and complex regulatory calendar, and have been adopted by the Board to serve a variety of functions. In some cases they are used to assist applicants in understanding what they should file to support their applications: for example the *Environmental Guidelines for Hydrocarbon Pipelines and Facilities in Ontario*.

18. Other such guidelines can have a more direct impact on the rates that are set by the Board through a subsequent hearing process. For example, the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* establishes a methodology for establishing a utility's allowed cost of capital, which is a significant component of the revenue requirement that is recovered through rates. Similarly, the Board's Guidelines and Reports on 3rd Generation Incentive Regulation Mechanism establish the methodology by which many electricity utility's rates are adjusted annually.

19. However, the Board acknowledges that because these guidelines are not orders of the Board, they are not binding on any party. In order to actually issue an order with respect to the matters covered by these guidelines, the Board must still conduct a hearing. Generally speaking, these guidelines will be considered by the Board panel assigned to any hearing to which they are relevant, but the panel is not bound to follow them.

20. The process the Board adopts in considering and adopting guidelines varies depending on the nature of the guideline. In most cases, at a minimum, the Board will takes steps to give notice to potentially affected parties, and provide an opportunity to comment. In some cases, for example the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, the Board invited the parties to file their own independent expert reports relevant to the subject matter for the Board's consideration, and held a technical conference, in which interested parties, and their legal counsel and experts, were involved in discussing the issues under consideration.

21. The process followed by the Board to develop the DSM Guidelines that are challenged by the Applicant in this judicial review lies somewhere between these examples, in terms of formality and the involvement of interested parties.

22. However, the Board acknowledges that the process used to develop the DSM Guidelines at issue in this judicial review was not a "hearing" for the purposes of ss. 21(2) of the *Ontario Energy Board Act*, and that the DSM Guidelines are not an order of the Board.

AFFIRMEDBEFORE ME at the city of Torontoon March 15, 2012.	
Commissioner for Taking Affidavits	MICHAEL MILLAR

TAB 9

CITATION: Pollution Probe Foundation v. Ontario Energy Board, 2012 ONSC 3206
DIVISIONAL COURT FILE NO.: 221/11
DATE: 20120530

ONTARIO

SUPERIOR COURT OF JUSTICE

DIVISIONAL COURT

JENNINGS, HOCKIN AND SWINTON JJ.

BETWEEN:	
POLLUTION PROBE FOUNDATION Applicant	*Murray Klippenstein* and *Basil Alexander*, for the Applicant
– and –	
ONTARIO ENERGY BOARD Respondent	*M. Philip Tunley* and *Justin Safayeni*, for the Respondent
	Mark Rubenstein, for the Intervenor School Energy Coalition
	Robert B. Warren, for the Intervenor Consumers Council of Canada
	HEARD at Toronto: May 30, 2012

SWINTON J. (ORALLY)

[1] The applicant, Pollution Probe Foundation, seeks judicial review of a March 29, 2011 letter of the Ontario Energy Board ("the Board"), which included draft Demand Side Management ("DSM") guidelines to be used in natural gas rate hearings. As well, the applicant challenges the final guidelines issued June 30, 2011. In particular, the applicant submits that the Board made a decision to impose budget caps in the March letter.

[2] The applicant argues that the process for adopting the guidelines was improper, as no hearing was held under s.21(2) of the *Ontario Energy Board Act*, S.O. 1998, c. 15, Sched. B ("the Act"). In particular, the applicant objects to the budget caps and argues that a hearing was required because the guidelines are, in effect, binding on the Board and parties.

[3] The Board, supported by the intervenors, the Consumers Council of Canada and the School Energy Coalition, seeks to have the application quashed as moot.

[4] There have been two rate hearings since the DSM guidelines were issued involving Union Gas Limited and Enbridge Gas Distribution Inc. The applicant participated in both those proceedings. In both cases, the Board approved arrangements that departed from the DSM guidelines. As well, a member of the panel in the Union Gas hearing, Cathy Spoel, expressly acknowledged that the guidelines are not binding. In addition, counsel for the Board filed an affidavit for this application in which he stated that the guidelines are not binding on any party, as they are not orders of the Board. He stated at paragraph 19 of his affidavit:

> Generally speaking, these guidelines will be considered by the Board panel assigned to any hearing to which they are relevant, but the panel is not bound to follow them.

[5] As a result, there is no longer a live controversy as to whether the Board considers the guidelines to be binding, and the application for judicial review is moot (see *Borowski v. Canada (Attorney General),* [1989] 1 S.C.R. 342 at para. 15).

[6] While the Court has a discretion to hear an application despite its mootness, we would not exercise that discretion here. The applicant has another avenue to challenge the DSM guidelines, including the budget caps, in a rate proceeding before the Board. We note that the applicant chose not to travel that route in the two rate hearings already held.

[7] We decline the applicant's invitation to give a declaration about the non-binding nature of the guidelines. Unless the Board applies the guidelines in a binding fashion, the Court should not address the issue.

[8] The motion to quash is granted, and the application for judicial review is quashed.

JENNINGS J.

COSTS

[9] I endorse the Record, "This application is quashed for reasons delivered today by Swinton J. Having had the benefit of submissions from counsel, we fix costs to be payable by Pollution Probe to the Board at $2,500."

SWINTON J.

JENNINGS J.

HOCKIN J.

Date of Reasons for Judgment: May 30, 2012
Date of Release: June 4, 2012

CITATION: Pollution Probe Foundation v. Ontario Energy Board, 2012 ONSC 3206
DIVISIONAL COURT FILE NO.: 221/11
DATE: 20120530

ONTARIO

SUPERIOR COURT OF JUSTICE

DIVISIONAL COURT

JENNINGS, HOCKIN AND SWINTON JJ.

BETWEEN:

POLLUTION PROBE FOUNDATION

Applicant

– and –

ONTARIO ENERGY BOARD

Respondent

ORAL REASONS FOR JUDGMENT

SWINTON J.

Date of Reasons for Judgment: May 30, 2012

Date of Release: June 4, 2012

TAB 10

Interrogatories for Sean Russell (Commercial Manager/Interim Plant Manager of London District Energy Inc., subsidiary of Veresen Inc.)

INTERROGATORY #5

Has Veresen pursued all of its energy savings opportunities with a TRC benefit/cost ratio of 1.0 or better? If "no", please explain why not.

RESPONSE

Energy efficiency programs are pursued on an ongoing and planned basis, taking into account various investment criteria which depend on the nature and scope of the specific energy efficiency initiative. Project benefit-to-cost ratios will change over time as equipment ages and requires further maintenance, with the input costs of fuel and with the price of electricity. This systematic pursuit of energy efficiency is part of LDE's regular business planning because it makes good business sense. Plant management is in the best position to determine which projects are economic and which ones are not. The economic tests applied to the various energy efficiency initiatives will be the same whether or not an opt-out program is approved by the Board.

LDE has included DSM funding in the past as a benefit in the overall economics of energy efficiency projects. This makes sense once the Board has approved a DSM program and the rates are set based on recovery of these DSM costs. At this point in time, the DSM program for 2013 and 2014 has not been approved, nor are the rates approved to recover such DSM costs. An appropriate economic analysis at this time should not only reflect the DSM funding that might be received to support an energy efficiency initiative, but should also reflect the real costs of providing the DSM program. These real costs of providing the DSM program are paid for by the rate payer and are a combination of both the higher distribution rates that result from recovery of the DSM program costs as well as the one-time costs charged to rate payers by Union related to the clearing of the DSM variance accounts at the end of the year. The variance accounts include variances in actual DSM spending as well as Union incentive payments.

It is worth noting that, at Exhibit B5.7, APPrO requested certain information and received the following response:

> Question:
>
> d) Please recalculate the percentage of the 'DSM amount' that is directly allocated to supporting energy-efficiency projects if the incentive payments are included in the calculation assuming 100% payout,
>
> Answer:
>
> d) If the 100% DSM Utility Incentive is included in the calculation 67% of the DSM amount is directly allocated to supporting energy-efficiency projects.

It is clear from this response that at a 100% incentive payout (and assuming no other variances), only 67% of the total amount paid by ratepayers ends up going to support energy efficiency projects. Put another way, for each $1,000 dollars of DSM funding received by customers from Union, the customer pays $1,500 in rates and other charges. If the real costs of providing the DSM program are included in the economic tests to evaluate energy efficiency projects, then in fact the DSM program should result in fewer energy efficiency projects being economic and subsequently pursued.

INTERROGATORY #6

Please fully describe Veresen's investment criteria for energy efficiency investments, including the required pay-back period, required rate of return, and maximum time horizon.

RESPONSE

See response to Environmental Defence IR #5 above.