Nova Scotia Utility and Review Board

IN THE MATTER OF *The Public Utilities Act*, R.S.N.S. 1989, c.380, as amended

- and -

IN THE MATTER OF An Application to Approve Nova Scotia's Demand Side Management Plan for 2010 and Demand Side Management Cost Recovery Rider.

Evidence of NSPI

April 7, 2009

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1.0 INTRODUCTION

This document contains the evidence of Nova Scotia Power Inc. (NSPI, the Company) and its consultants in support of a Demand Side Management (DSM) conservation and energy efficiency program for 2010.

In 2007, NSPI filed its Integrated Resource Plan (IRP) which concluded that DSM was an important part of the Company's least cost resource plan for meeting future electricity requirements for Nova Scotia. The IRP identified the next step for DSM as:

> NSPI will initiate the development of a comprehensive DSM program, aimed at realizing the potential indicated in the IRP analysis. The ramp-up proposed in the IRP analysis can serve as a benchmark for the plan.[1]

In 2007, the Utility and Review Board (UARB, the Board) established a collaborative process between NSPI and UARB staff and consultants (the DSM Collaborative), and a consultative process with stakeholders to establish a DSM plan and to examine administrative issues related to DSM. The Board subsequently established a timeline for a DSM Hearing in 2008.

On January 31, 2008 the DSM Collaborative filed reports entitled "DSM Administrative Issues Analysis" and "DSM Programming Plan 2008-2010 and Framework to 2013". On the same date, NSPI filed Evidence seeking approval of the DSM programming plan (including early action DSM programs) and a cost recovery approach for DSM expense and effects.

In early 2008, the Province of Nova Scotia initiated a stakeholder consultation process, facilitated by Dr. David Wheeler of Dalhousie University Faculty of

[1] NSPI Integrated Resource Plan (IRP) Report Volume 1, July 2007, page 41.

Management, to examine administration and accountability models for DSM and provide a recommendation to government regarding future DSM administration.

A settlement agreement was reached in the 2008 DSM proceeding, which contemplated future transfer of DSM programs to a new Administrator and deferred addressing a number of items on the Issues List for the Board's DSM Hearing.

In its May 7, 2008 Decision, the UARB approved the settlement agreement, as well as NSPI's DSM programs for 2008 and 2009 at an investment level of up to $12.9 million. This amount was subsequently included in rates through the 2009 rate case proceeding. The UARB directed NSPI to apply, by March 31, 2009, for approval of 2010 DSM programs if a new Administrator was not in place or was unable to propose programs.[2] In its letter of March 25, 2009, the UARB subsequently extended the filing date to April 7, 2009.

The Dalhousie-facilitated consultation process concluded in December 2008, with a final report entitled "Stakeholder Consultation Process for an Administrative Model for DSM Delivery in Nova Scotia". This report is included in Appendix A. It recommended the establishment of an independent body, tentatively named the Nova Scotia Electricity Efficiency Agency, to act as administrator of DSM programs. The Nova Scotia Provincial Government subsequently announced that the new DSM Administrator's Board of Directors would be recruited in early 2009 and that enabling legislation would be passed in the spring of 2009. The Government also announced that DSM would be funded by electric customers. Media releases related to the Dalhousie recommendation and Government announcement are included in Appendix B.

[2] NSPI 2008 DSM Plan, UARB Decision, NSUARB – NSPI – P-884, May 7, 2008, page 17, paragraph 30.

The new DSM Administrator is not yet in place. This Application is made in accordance with the Board's directive that, in these circumstances, NSPI file for approval of 2010 programs. NSPI will work with the new Administrator, once established, to ensure 2010 DSM programs are transitioned.

The parties to the 2008 settlement agreed to delay determination of a number of issues[3] which are unaffected by the establishment of the new Administrator. It is appropriate to consider these issues at this time, including:

- DSM cost allocation
- DSM lost contribution to fixed costs
- DSM cost recovery approach

The 2010 DSM plan and the Company's proposal on these issues were reviewed with stakeholders at a Technical Conference held on February 3, 2009. Through recent negotiations involving the Company and several stakeholders, a consensus was reached with respect to the allocation of DSM costs and that a DSM cost recovery rider should be adopted by the UARB. The approach that NSPI proposes, and which appears to have broad support is included as Appendix G.

With this Application, NSPI seeks approval of:

1. The 2010 DSM Programming Plan
2. The proposed allocation of DSM program costs per Appendix G.
3. The DSM Cost Recovery Rider (the Rider), which includes program and lost contribution to fixed costs to be recovered via electric bills

[3] NSPI 2008 DSM Plan, Settlement Agreement, NSUARB – NSPI – P-884, March 5, 2008, page 3, clause 9.

4. Recovery of DSM costs using the Rider

NSPI requests that the UARB extend the Program Development Working Group (PDWG) and its advisory role beyond 2009 until such time as the new Administrator is in place and seeks changes to the PDWG.

This filing contains the testimony of NSPI regarding energy efficiency and conservation programming for 2010. It also contains the evidence of the Company and its expert, Steve Seelye, regarding the recovery of costs of energy efficiency and conservation, including the specific proposal for which the Company seeks approval.

2.0 OVERVIEW OF DSM PROGRAMS

DSM program expenses and savings for 2008 to 2013 are shown in Figure 2.1. While program approval is being requested for 2010 only, this table provides projections for future years.

Delivery of 2010 DSM programs is expected to cost $22.9 million. Projected incremental demand and energy savings are 16.9 MW and 82.7 GWh, respectively.

Figure 2.1

DSM Targets 2008-2013						
Year	**Incremental Demand Savings (MW)**	**Cumulative Demand Savings (MW)**	**Incremental Energy Savings (GWh)**	**Cumulative Energy Savings (GWh)**	**Incremental Program Cost ($ millions)**	**Cumulative Program Cost ($ millions)**
2008*	2.1	2.1	16.1	16.1	3.2	3.2
2009*	6.8	8.8	50.3	66.3	9.7	12.9
2010**	16.9	25.8	82.7	149.0	22.9	35.8
2011***	30.9	56.7	145.8	294.8	41.1	76.9
2012***	44.0	100.7	204.9	499.6	60.6	137.5
2013***	63.5	164.2	305.3	804.9	81.9	219.4

Notes:
The numbers in this figure may not sum exactly due to rounding.
* Approved Programs (expressed in 2008 dollars)
** Proposed 2010 DSM Targets (expressed in 2010 dollars)
*** Potential DSM investment in future years – for context only (expressed in 2010 dollars)

For comparison purposes, the January 31, 2008 DSM Plan filed with the UARB is shown in Figure 2.2.

Figure 2.2

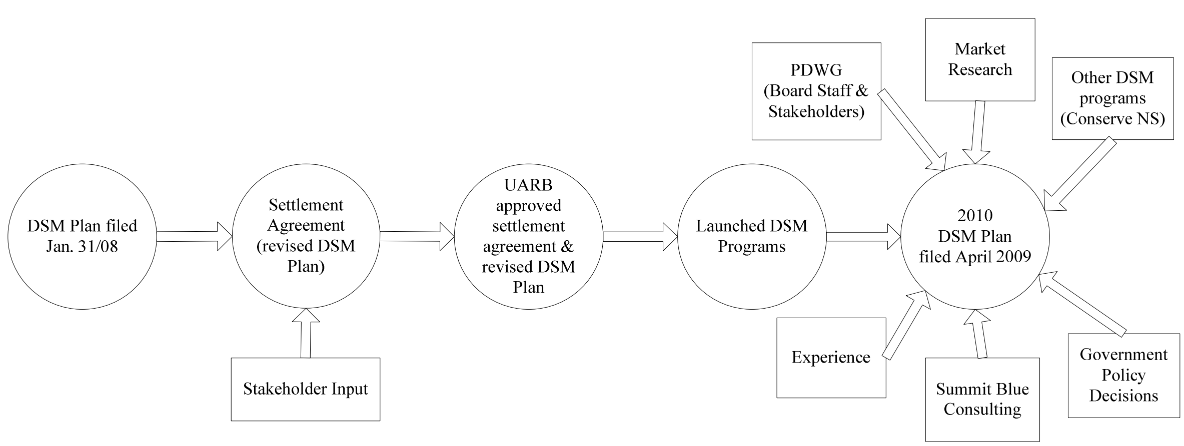
DSM Plan as filed January 31, 2008							
Year	**Incremental Demand Savings (MW)**	**Cumulative Demand Savings (MW)**	**Incremental Energy Savings (GWh)**	**Cumulative Energy Savings (GWh)**	**Incremental Program Cost ($ millions)**	**Cumulative Program Cost ($ millions)**
2008	1.7	1.7	15.2	15.2	2.7	2.7
2009	7.1	8.8	50.8	66.0	10.2	12.9
2010	15.0	23.8	108.7	174.7	21.2	34.2
2011	27.0	50.8	153.1	327.8	39.0	73.2
2012	41.5	92.3	278.8	606.6	58.6	131.8
2013	55.5	147.8	371.8	978.4	78.2	210.0

Notes:
The numbers in this figure may not sum exactly due to rounding.
This figure is expressed in 2008 dollars.

While the 2010 investment amounts contemplated in the January 2008 filing are approximately equal to those requested in the current plan, the proposed 2010 programs savings are different. The 2010 incremental demand savings are greater than those listed in the 2008 plan (16.9 vs. 15.0 MW), and the incremental energy savings are less by 26 GWh (82.7 vs. 108.7 GWh).

Figure 2.3 provides an outline of the key factors that were considered when updating the DSM plan for 2010.

Figure 2.3



The 2010 DSM plan has evolved from that filed on January 31, 2008, based on stakeholder feedback obtained during the DSM settlement agreement process, program implementation experience to date, and significant input from the PDWG, including its independent consultant, Mr. Blair Hamilton from Vermont Energy Investment Corporation. The plan takes into consideration relevant government policy changes (e.g. phasing out of incandescent lights) and changes to the electricity based programs of other entities involved in advancing conservation and energy efficiency (e.g. Conserve Nova Scotia and Natural Resources Canada). NSPI received the advice and assistance of its consultant, Summit Blue, in the development of the plan.

Although the current DSM plan is expected to deliver 26 GWh less in incremental energy savings in 2010 than was projected in the January 31, 2008 plan, this difference has already been more than offset by greater awareness and action by Nova Scotians to conserve energy, and assisted by the contributions of other electric DSM service providers. Since 2006, Conserve Nova Scotia has provided more than a quarter of a million compact fluorescent lights (CFLs) to Nova Scotians. In the same time period, Conserve Nova Scotia's upstream lighting program resulted in the installation of over half a million high performance fluorescent lamps. These two lighting programs together have resulted in an estimated annual energy savings of 34 GWh.

The original 2007 IRP targets are shown in Figure 2.4. Since DSM investment began almost a year later than contemplated in the IRP, the 2013 figures shown in the tables above are comparable to the 2012 IRP figures. The 2010 Plan is consistent with the direction provided in the IRP. The proposed program investment and savings are achievable yet challenging, and can be efficiently transitioned to the new DSM Administrator once established.

Figure 2.4

2007 Integrated Resource Plan (IRP)						
Year	**Incremental Demand Savings (MW)**	**Cumulative Demand Savings (MW)**	**Incremental Energy Savings (GWh)**	**Cumulative Energy Savings (GWh)**	**Incremental Program Cost ($ millions)**	**Cumulative Program Cost ($ millions)**
2008	11.4	11.4	77.8	77.8	16.4	16.4
2009	18.2	29.6	124.5	202.4	26.3	42.7
2010	30.6	60.2	186.8	389.2	41.3	84.0
2011	40.6	100.8	233.6	622.8	53.1	137.1
2012	46.2	147.0	249.2	871.9	58.3	195.4
2013	51.7	198.6	264.8	1136.7	63.5	258.9

Notes:
The numbers in this figure may not sum exactly due to rounding.
This figure is expressed in 2006 dollars.

2.1 Proposed 2010 Programs

Figure 2.5 presents estimates of program expenses, the number of program participants or units, the incremental annual energy savings (GWh), and demand savings (MW), and the total resource cost (TRC) test ratio for the 2010 DSM programs.

Figure 2.5

2010 DSM Plan	**Budget* ($ millions)**	**Number of Participants / Units**	**Incremental Annual Net Energy Savings at Generator (GWh)**	**Incremental Annual Net Demand Savings at Generator (MW)**	**Total Resource Benefit/Cost Ratio (TRC)**
Residential					
Efficient Products *	2.07	40,661	8.86	1.86	1.9
Existing Homes *	2.12	2,700	4.93	1.41	1.6
Low Income Households *	2.18	1,500	5.26	1.17	2.0
New Homes *	2.07	1,000	4.37	1.40	1.4
Residential Subtotal	**8.44**	**45,861**	**23.43**	**5.84**	**1.7**
C&I					
Rx Rebate	0.15	-	-	-	-
Custom *	6.26	120	38.19	6.40	3.1
Small Business DI Lighting *	5.62	600	13.98	3.30	1.8
New Construction *	1.76	35	7.06	1.38	2.7
C&I Subtotal	**13.80**	**755**	**59.23**	**11.08**	**2.6**
Multi Sector					
Education and Outreach	0.40	-	-	-	-
Development and Research *	0.25	-	-	-	-
Multi Sector Subtotal	**0.65**	-	-	-	-
TOTAL	**22.89**	**46,616**	**82.67**	**16.92**	**2.3**

Notes:
This figure is expressed in 2010 dollars.
* Programs established in 2008/2009.

A description of the programs that form the 2010 DSM plan is provided in Appendix C. At the February 3, 2009 Technical Conference, the preliminary 2010 plan was shared with the broader stakeholder group.

The details of the programs put forward in this plan for 2010 implementation will need to be further developed and refined in 2009 and 2010. NSPI will continue to work with the PDWG on such detailed design and implementation plans until the programs are transferred to the new DSM Administrator.

It is anticipated that through a DSM working group, the DSM Administrator will have latitude and flexibility to make appropriate mid-course corrections and adjustments to the programming mix within the total target amount.

There are policy issues regarding fuel substitution (switching to renewable energy sources or to other conventional fuels) that require further work. Through the PDWG it is anticipated that these issues will be studied and addressed in 2009.

It is anticipated that processes of Evaluation and Annual Savings Verification for the 2010 DSM programs will be as developed for the 2008-2009 DSM programs:

- DSM Program Evaluation (process and impact) will be undertaken by an independent firm under contract with the DSM Administrator.
- DSM Annual Savings Verification will be undertaken by an independent firm under contract with the Board.

3.0 OWNERSHIP OF ENVIRONMENTAL CREDITS

On January 30, 2009, Dan English, Chief Administrative Officer of Halifax Regional Municipality (HRM), filed a letter with the UARB regarding environmental credits associated with DSM. Specifically, Mr. English referred to two projects that HRM has submitted for funding under NSPI's Commercial & Industrial (C&I) Custom program.[4] Subsequent to Mr. English's letter, the UARB advised that this topic would be part of the Issues List in the upcoming DSM proceeding. Both of these letters are included in Appendix D.

From its inception in mid 2008 to March 31, 2009, the C&I Custom program has signed development agreements with 16 different C&I participants to implement 22 energy saving projects. In each case, the project development agreement makes it clear that NSPI retains ownership of any environmental credits which may be claimed from the reduction in emissions associated with the electricity reductions from the project**.** These credits are retained for the benefit of NSPI's customers. As NSPI is the entity that will be regulated with respect to electricity related greenhouse gas (GHG) emissions, this clause is of critical importance to ensure lowest cost alternatives are achieved for the benefit of all customers.

HRM suggests that the C&I Custom program terms and conditions be modified, so that HRM would retain some portion of any GHG credits, possibly in proportion to their financial contribution to the project.[5]

NSPI strongly recommends the program design remain unchanged with respect to ownership of environmental credits. Key reasons include:

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[4] It should be noted that the figures cited by Mr. English do not exactly align with NSPI's calculations for these projects. In particular, the stated 2000 GWh associated with these projects is in fact expected to be approximately 3 GWh on an annual basis.

[5] This section of evidence is written as if individual customers will be able to own and resell electricity related GHG credits. NSPI's understanding is that the rules as currently drafted would not permit this.

1) The Competitiveness of DSM with Supply Side Alternatives Would Decline

The Integrated Resource Plan identified that investments in DSM and renewable energy are significant elements of the preferred plan for meeting Nova Scotia's long term electricity needs. The net present cost of this alternative was estimated to be approximately $1 billion lower than other alternative plans, some of which featured a large fossil fuel based power plant. In the preferred plan, DSM will, over time, eliminate the need for additional supply-side generation.

In the IRP analysis, avoiding generation through DSM is considered non-emitting, and no emissions credits are required to be purchased for the MW and GWh saved. This is consistent with the acquisition of renewable energy supply and is a feature of NSPI's renewable energy contracts today. This is an advantage over a fossil fuel supply option, where credit costs would be incurred.

If customers were to retain GHG credits associated with DSM programming, the IRP economics of DSM versus supply side options would be altered. Transferring ownership of carbon credits as suggested would reduce the "no-emissions" benefits of DSM versus supply options and increase the overall cost of DSM based options.

2) Other Customers Would Pay More

Assuming DSM remained competitive if participants retain GHG credits, NSPI's DSM programs are designed to maximize the benefits per dollar invested, and therefore minimize the cost to the utility's customers overall. Since DSM participants would be making the largest contributions, presumably, under the proposed approach, most of the GHG credits would be retained by them. Participants would then either sell the credits to regulated Large Final Emitters[6] (either directly or through a market), or retire them so that they could not be used.

If NSPI expected to find itself above its regulated level for GHG emissions, it would then need to undertake other measures to reduce its emissions or, if permitted, buy credits. NSPI could end up buying the very credits retained by participants whose projects were enabled by DSM funding.

This arrangement would result in a transfer of costs from participating DSM customers to non-participating DSM customers. In effect, non-participating customers would pay twice - once in DSM incentives to facilitate the savings, and again for carbon credits.

3) Participants Can Consider the Value of Credits In Their Projects

If a potential DSM participant values retaining GHG credits, it can consider such value in its project proposal to the DSM Administrator. The Administrator can then properly evaluate the proposal versus other DSM project proposals. If, as a result, the project is not competitive against

[6] It is currently understood that any source that emits a minimum of 100,000 tonnes/year of CO_2e is considered a Large Final Emitter.

other DSM opportunities, the project owner can pursue the energy efficient project without DSM program funding, and sell the GHG credits it generates.

The current C&I Custom program can and will be successful without making changes to its environmental credit provisions. NSPI and the new Administrator can meet the DSM targets by providing cost-effective incentives that enable customers to implement energy efficient projects. This will provide the maximum benefit of these investments for all customers, including the benefits associated with the acquired GHG credits.

4.0 DSM COST RECOVERY

DSM reduces variable energy costs and avoids capital costs of additional capacity. The costs of DSM include program costs and the loss of contribution to fixed costs that result from the reduction in NSPI sales associated with the DSM programs. The program costs must be recovered by the DSM Administrator and lost contributions to fixed costs must be recovered by the utility in a timely and effective manner.

The traditional ratemaking process of setting rates through general rate applications is not the most effective and efficient platform for the recovery of DSM costs which will vary as the programs develop and evolve. DSM-related costs can be more efficiently and accurately recovered by employing an alternate cost recovery approach. Such an approach makes it possible to implement new DSM programs and modify existing programs more effectively in response to new information as it becomes available.

Discussions with stakeholders have resulted in NSPI recommending a DSM program cost recovery approach that would facilitate changes to DSM programs as they unfold. The approach is designed on a forward-looking basis with a subsequent true-up to actual costs and participation to ensure accurate and timely recovery of costs. The DSM program cost allocation approach of the proposed DSM Rider would apply to all rate classes served by NSPI[7], would be effective January 1, 2010 in order to facilitate the delivery of DSM programs and would operate as outlined in Appendix G.

[7] With the exception of the Wholesale Market Non-Dispatchable Supplier Spill tariff and the Mersey System tariff (i.e., Basic Block).

The Company seeks approval of the DSM Cost Recovery Rider provided in Appendix E. This Rider includes recovery of DSM program costs as well as any lost contribution to fixed costs resulting from DSM-reduced electricity sales.

The Company has retained Mr. Steve Seelye of the Prime Group as its DSM cost recovery consultant. Mr. Seelye has previously worked with NSPI and interested parties to develop the Fuel Adjustment Mechanism (FAM), and is familiar with the Company and the perspectives of its customer groups. NSPI supports and adopts the testimony of Mr. Seelye.

In the following sections, NSPI presents evidence on its proposed approach to the accounting treatment of the DSM-related costs, the allocation method of these costs among rate classes, and the pricing approach to recover these costs. The supporting evidence on the proposed DSM pricing design, as filed by Mr. Seelye, concludes this section.

4.1 Accounting Treatment of DSM-related Costs

The 2009 General Rate Application settlement agreement, as approved by the Board, provided for amortization of 2008-2009 DSM costs over six years.[8] While that was an acceptable one-time solution for a transitional year, it is not an appropriate basis for the ongoing administration of increasing DSM costs.

Amortization converts a large expenditure and its carrying cost to an annual amount, spread over the period in which the expenditure will be useful. This is an appropriate way to deal with, for example, a major investment in generation. However, the IRP identifies ongoing DSM programs as an effective alternative to one-time new investments in generation. It contemplates annual expenditures for

[8] NSPI 2009 Rate Case, UARB Decision, NSUARB – NSPI – P-888, November 5, 2008, page 13, paragraph 11.

DSM for the life of the IRP planning period – more than 20 years. Conceptually, a single potential large investment in generation is replaced by an annual expenditure for DSM – already effectively spreading the cost over time.

If annual DSM expenditures were to be amortized, the balance to be amortized increases rapidly for a few years and then, assuming DSM costs level out, would reach a steady state in which the annual payments recovered equal the annual DSM expenditure (plus the carrying cost of the unamortized balance). The only result would be a short term deferral, and costs borne by customers would thereafter be higher to recognize the cost of carrying the unamortized balance.

The cost recovery approach approved in this proceeding should be capable of being transitioned to the new Administrator when it assumes responsibility for DSM programs. It is not clear how the Administrator would obtain the necessary capital to fund the deferral of DSM expenditures through amortization as the Nova Scotia Government has not indicated that it will provide such a capital base.

DSM cost amortization is not in the best interests of the Province, the utility or customers and should not be contemplated for the future. DSM expenditures should be recognized as an annual expense, to be recovered in the year expended.

4.2 Allocation of the DSM Administrator's Program Costs

There is no single, universally accepted method in the electric industry for allocation of DSM costs. As described previously, after stakeholder discussions, there appears to be support for the manner proposed by NSPI in this Application for the allocation of DSM program costs.

Under this approach, 25 percent of DSM program costs (the assumed portion of these costs meant to represent system benefits provided to all customers), is to be allocated to customer classes in the same way that fixed generation costs are allocated in the most recent Cost of Service Study (COSS) approved by the UARB.

Following this approach, 25 percent of annual DSM program costs are to be “functionalized” as 100 percent generation-related. These costs are then “classified” as energy- and demand-related using the weighted average classification factors which apply to generation assets. The DSM costs classified as energy- or demand-related will then be allocated among rate classes using the same approach used for the allocation of fixed generation costs. Energy-related costs are allocated using the relative shares of annual energy requirement of all rate classes. Demand-related costs are allocated using the relative shares of all class contributions to the three winter coincident peaks (3CP). Please refer to Table 1 of Appendix F.

As specified in Appendix G, the remaining 75 percent of DSM program costs would be allocated to individual classes in proportion to their participation in DSM programs. This participation would be forecast by the DSM Administrator based upon the anticipated DSM programs. The actual participation would be subsequently measured and a true-up of cost allocation would occur so that cost allocation will more accurately reflect program participation by class.

4.3 NSPI's DSM Cost Recovery Approach

NSPI's proposed DSM Cost Recovery Rider includes three components:

1. A DSM Program Cost Recovery (PCR) component that provides for the recovery of DSM program costs (including administration costs)
2. A Lost Contribution to Fixed Costs (LCFC) component that provides for the foregone recovery of fixed costs associated with lost sales
3. A DSM Balance Adjustment (BA) that reconciles any over- or under-recovery of program costs, lost contribution to fixed costs, and previous billings of the BA

NSPI proposes that each of the DSM cost recovery components be submitted to the UARB on or before October 1 of each year, with DSM cost recovery charges to be effective on the following January 1, once approved by the UARB. Per the Agreement, the cost recovery components would be forward-looking based on projected costs for the upcoming year. The true-up component (BA) would reflect the difference between actual costs and billed amounts for the prior year's DSM activities and differences in participation from forecast.

Appendix F contains illustrative calculations showing how the DSM Rider will function.

4.3.1 Recovery of DSM Program Costs

DSM program costs are proposed to be recovered through a Program Cost Recovery charge expressed in cents per kWh. This component is calculated by dividing the forecast year's anticipated program costs, as allocated to each class, by the forecast energy sales (kWh) for that class. The forecast energy sales reflect the anticipated effect of the DSM programs.

The allocation of DSM program costs for the year 2010 is illustrated in detail in Tables 1, 2 and 3. The allocation of the remaining DSM program costs for the following four years are presented using the same methodology in Table 4. As shown in Table 9 of Appendix F the PCR is the first of three components of the recovery mechanism.

4.3.2 Recovery of Lost Contribution to Fixed Costs

Fixed costs are those costs which do not vary with the volume of energy sales or billing demands. These costs are recovered through a contribution provided in the price for each unit of energy or demand sold by the utility. When sales are reduced through DSM activities, those costs are still incurred. They are not recovered through the remaining sales revenue because the rates for those sales were set on the basis of the original sales forecast. Absent an appropriate recovery mechanism, the utility would not recover these costs. This is contrary to the principles upon which rates are approved.

In order to ensure that sufficient revenue is collected to recover fixed costs, the DSM rider includes an adjustment for lost contribution to fixed costs resulting from sales reductions due to DSM. The LCFC component grows cumulatively every year, reflecting the accumulated under-recovery of fixed costs, until such time as the rates are reset in a general rate case.

The LCFC component, like the PCR component, is forward-looking and has a true-up adjustment. The LCFC is calculated for individual rate classes by multiplying its estimated unit fixed costs[9] (in cents per kWh) by its accumulated lost sales[10] as projected for the next year (since the time the rates were last set pursuant to a general rate application). The unit fixed costs are calculated by dividing the annual fixed costs of each class by its annual sales. The estimated unit fixed costs for each class is calculated by subtracting variable costs (after adjustment for the revenue to cost ratio), and customer charge revenue from the total class revenue, and then dividing this remaining portion of the class revenue by the class energy sales. All inputs into these calculations are based on the most recent general rate application, as shown in Table 6 of Appendix F. Table 7 of Appendix F illustrates these calculations over the five year period from 2010 to 2014 using hypothetical information regarding the sales reduction due to DSM programs, and cost of service information from the 2009 Compliance Filing.

4.3.3 DSM Balance Adjustments

Because the PCR and LCFC components are set prospectively and are based on forecasts, actual DSM costs may not be recovered precisely during the year the programs are run. Actual DSM program costs and participation levels targets may differ from those assumed at the time the charge is calculated. Also, the actual energy sales for each class will differ from those projected for the following year for the purpose of the calculations. In order to ensure precise cost recovery, the PCR and LCFC components each include true-up adjustments.

The balance adjustment calculations for the PCR and LCFC components are prepared separately and lag two years behind the year for which they are

[9] The unit fixed costs reflects costs of providing electric service only. Unmetered Class revenue includes other revenue designed to recover costs associated with capital and maintenance. This non-variable revenue is not accounted for in these calculations.

[10] The projected accumulated lost sales from each rate class in the following year are the total of the engineering estimates of the historical accumulated lost sales, since the time of the most recent general rate application, for a class and the projected reduction in the current and next year's sales for that class.

calculated. This is because the information required for true-up is not available until after year-end.

The recovery of the true-up costs themselves will be administered separately for each class in the following years and included in future BA adjustments. The BA dollar amounts will be adjusted for the effect of the time value of money using NSPI's weighted average cost of capital (WACC).[11]

4.3.3.1 Balance Adjustments for the PCR Component

At the time of the DSM cost recovery submission, the actual amounts of revenue billed for each individual class' PCR component in the previous calendar year will be subtracted from the actual program costs incurred in that year and then allocated to that class to reflect actual participation levels in accordance with the Agreement. These residual program cost amounts from individual rate classes will be adjusted for the time value of money using NSPI's weighted average cost of capital. These adjusted residual class amounts are then divided by the expected energy sales from corresponding classes to arrive at a BA-PCR component for each class.

If actual costs incurred are lower than the amount of revenue collected, the BA-PCR component will be negative and will be a credit on future customer bills. If actual costs incurred are higher than the revenue collected, the BA-PCR component will be positive and will be a charge for future customer bills.

Table 5 of Appendix F illustrates the mechanics of the BA-PCR calculations. Table 9 of Appendix F shows all the components of the DSM Cost Recovery

[11] The residual BA dollar amounts will be multiplied by a factor reflecting the weighted average cost of capital of NSPI, as assumed in the last rate case. For example, using the weighted average cost of capital of 8.23% from the 2009 Compliance Filing gives an adjustment factor of $(1.0823)^2 = 1.17137$.

Rider. These calculations are illustrated over the five year time period from 2010 through 2014.

4.3.3.2 Balance Adjustments for the LCFC Component

At the time of the DSM cost recovery submission the actual amount of revenue collected under the LCFC component from the previous calendar year will be subtracted from the amount of foregone fixed costs associated with the actual DSM measures for that year to determine actual foregone fixed costs. This will be calculated for each relevant class separately and will reflect actual participation levels. This detail is required because, due primarily to differences in infrastructure requirements and line losses, rate classes have differing fixed costs per kWh.

The residual dollar amounts calculated for individual rate classes will be adjusted for the time value of money using NSPI's weighted average cost of capital. These adjusted residual amounts from each class will then be divided by the expected amounts of energy sales from each class to arrive at the BA-LCFC component for each applicable class.

If the amount of foregone fixed costs associated with actual DSM measures are lower than the amount of revenue collected under the LCFC components, the BA-LCFC component will be negative and will be a credit on future customer bills. If the amount of foregone fixed costs associated with actual DSM measures are higher than the amount of revenue collected, the BA-LCFC component will be charge for future customer bills.

Table 8 of Appendix F illustrates the mechanics of the BA-LCFC calculations. Table 9 of Appendix F shows all the components of the DSM Cost Recovery

Rider. These calculations are illustrated over the five year time period from 2010 through 2014.

4.3.3.3 Balance Adjustments for the BA Components

For the BA-PCR and BA-LCFC components, the balance adjustment amounts will be the difference between the amounts billed during the twelve month period from application of the BA and the balance adjustment amounts established for the same twelve month period.

The BA calculations are performed separately for the BA-PCR and BA-LCFC components of each rate class. They are labeled as BA-BA-PCR and BA-BA-LCFC in Tables 5 and 8 respectively in Appendix F. For the purpose of the DSM Rider in Appendix E, as presented under item 3 of the BA section, these two components are aggregated and treated as one BA-BA item in column G of the Table 9 of Appendix F. These calculations are illustrated over the five year time period from 2010 through 2014.

Direct Testimony of
William Steven Seelye
Prime Group LLC

4.4 Testimony of Steve Seelye, Prime Group LLC

Overview of NSPI's Proposed DSM Cost Recovery Rider

The DSM Cost Recovery Rider is designed to recover DSM program costs, including administration costs, and the portion of lost sales revenues that would otherwise have contributed to the recovery of fixed costs.

The implementation of DSM programs will, by design, result in lower sales to customers. NSPI's proposed DSM Cost Recovery Rider will provide for the recovery of the fixed costs portion of revenues from these lost sales due to the implementation of DSM programs. Unless some mechanism is put in place to recover these lost contributions, these fixed costs (which, by definition, are not avoided by the reduced production) will not be recoverable by the utility because the prices for remaining services have been set on the assumption that the fixed costs would be recovered over the original forecast volume of sales. It is important that utilities be able to recover these lost fixed costs contributions, regardless of who administers the DSM programs. Without the ability to recover these costs in a timely fashion, the utility and its investors would be penalized for assisting the Province in achieving its DSM goals.

NSPI's proposed DSM cost recovery mechanism will also include a reconciliation adjustment to ensure that there will not be any over- or under-recovery of either DSM program costs or foregone fixed costs caused by lost sales under the mechanism.

NSPI's proposed DSM Cost Recovery Rider will therefore consist of the following three components:

1. A DSM Program Cost Recovery (PCR) component that provides for the recovery of DSM program costs (including administration costs)
2. A Lost Contribution to Fixed Costs (LCFC) component that provides for the foregone recovery of fixed costs associated with lost sales
3. A DSM Balance Adjustment (BA) that reconciles any over- or under-recovery of program costs, lost contribution to fixed costs, and previous billings of the BA

The DSM Program Cost Recovery Component

The PCR component of the DSM Cost Recovery Rider will recover the cost of developing and implementing demand side management and energy efficiency programs. The PCR component will recover all expected costs for demand side management and energy efficiency programs that have been developed through a collaborative advisory process and approved by the UARB for each year. These program costs would include the cost of planning, developing, implementing, managing, monitoring, and evaluating DSM programs. In addition, all costs incurred by, or on behalf of, the collaborative process, including but not limited to costs for consultants, employees and administrative expenses, would be recovered through the PCR component.

Once the costs are allocated to the customer classes, the allocated costs would be converted to an energy charge (cents per kWh) by dividing the DSM costs allocated to each customer class by the projected annual energy sales (kWh) for the customer class. Any over- or under-recovery of actual DSM costs will be refunded or recovered through the application of the BA.

The Lost Contribution to Fixed Costs

A portion of the revenues from sales represents a contribution to the recovery of the fixed costs of the utility. These fixed costs are embedded in rate components, such as energy and demand charges, which are predicated on forecast billing determinants of energy sales and billing demands accordingly. While fixed costs do not vary with fluctuations in billing determinants, the collected revenues do. As energy sales and billing demands go down due to the effects of DSM programs a portion of utility fixed costs is not recovered. The alternative for recovering these costs would be frequent general rate cases to reset rates – a process that can be costly and inefficient.

The LCFC component is an adjustment mechanism designed to recover these lost fixed costs, which would apply to all of the demand side management programs that NSPI (or the independent Administrator) will pursue. Implementing this approach for all demand side management programs will allow NSPI to recover the lost contributions to fixed costs associated with not selling units of energy due to the success of the DSM programs in reducing electricity consumption. Failure to include such a component would unreasonably penalize NSPI for the success of the programs.

For each upcoming year, the forecast reduction in customer usage by class (measured in kWh) for the approved DSM programs would be multiplied by the class' unit fixed costs to determine the lost contribution to be recovered.

The fixed costs recovery portion of revenue requirement for each customer class would be determined by calculating:

1. the class unit fixed costs per kWh resulting from the application of energy charges and demand charges (where applicable), but excluding customer charges, applied to the test year billing determinants from NSPI's most recent general rate decision, less
2. the variable costs, adjusted for the class's revenue to cost (R/C) ratio, as determined from the COSS approved in NSPI's most recent general rate decision.

Variable costs would include fuel costs (less export revenues), the variable cost component of purchased power expenses, and variable operation and maintenance expenses related to NSPI's production facilities.

The foregone contribution to the recovery of fixed costs calculated for each customer class would then be divided by the expected energy sales (kWh) for the customer class for the upcoming twelve month period to determine the applicable LCFC rate component. Recovery of foregone fixed costs from lost sales would be included in the LCFC component until the implementation of new rates pursuant to a general rate case.

Because the revenues collected by the LCFC component would be calculated based on forecast program targets, participation levels and sales, there would be a true-up at the end of the year. Any difference between the lost contribution collected by the LCFC component and the amount of lost contribution to fixed costs associated with actual DSM measures would be reconciled in future billings under the BA component.

Why a True-up Component is Needed and How it is Constructed

A true-up component is needed to ensure that the PCR and LCFC components of the DSM Cost Recovery Rider neither over-recover nor under-recover actual costs. The BA component of the DSM Cost Recovery Rider provides this true-up mechanism. The BA component would be calculated on a calendar year basis and would reconcile the difference between the amount of revenues actually billed through the PCR, LCFC, and previous application of the BA, and the revenues which should have been billed, in order to ensure accurate recovery, as follows:

1. For the PCR component, the balance adjustment amount for each class would be the difference between the amount billed in a twelve month period through the application of the PCR unit charge and the actual cost of the approved programs during the same twelve month period.
2. For the LCFC component, the balance adjustment amount for each class would be the difference between the amount billed during the twelve month period through the application of the LCFC unit charge and the amount of the foregone recovery of fixed costs due to lost sales resulting from actual DSM measures implemented during the twelve month period.
3. For the BA component, the balance adjustment amount will be the difference between the amount billed during the twelve month period through the application of the BA and the balance adjustment amount established for the same twelve month period.

The sum of these three balance adjustment amounts for each customer class would be divided by the expected energy sales for each customer class for the upcoming twelve month period to determine the BA for billing purposes.

DSM Cost Recovery Components in Other Jurisdictions

The PCR, LCFC, and BA are standard components included in DSM cost recovery mechanisms, are widely used in the industry, and have been adopted by a number of other regulatory boards and commissions. DSM program cost recovery mechanisms have been adopted in at least 24 state jurisdictions in the United States. Mechanisms providing for the recovery of lost fixed costs contributions have been adopted in Kentucky, Minnesota, Iowa, Connecticut, Massachusetts, Oregon, Indiana, New Jersey, California, Maryland, Oregon, Vermont, New York, Missouri, and Georgia.

Conclusion

In my opinion the DSM Cost Recovery Rider proposed by NSPI will appropriately recover the costs of DSM programs and the lost contribution to fixed costs associated with sales reductions resulting from the success of the DSM programs. The mechanism is fair to NSPI and to customers. It will encourage and enable successful DSM program implementation. It represents a conventional approach and includes best practice elements from mechanisms which are working effectively in various US jurisdictions.

5.0 DSM REGULATORY PROCESS

Section 2.1 of this Evidence (Proposed 2010 DSM Programs) describes the DSM plan for the upcoming year. Section 4.0 (DSM Cost Recovery) describes the method under which the costs associated with this plan are allocated, tracked and collected. As DSM programs are implemented in 2010 and beyond, both the program plan and the cost recovery amounts must be approved in advance of the year by the UARB. In conjunction with the proposed Rider, this section of Evidence outlines the regulatory steps for these approvals. The process will ensure thorough and timely review and UARB oversight, while working within existing electric utility regulatory requirements and processes.

Early in the year, the Administrator will file its DSM plan for the following year or for multiple years with the UARB. This filing will be supported by a hearing and stakeholder process, as determined by the UARB, in which this proposed plan will be examined. As a result of this process, the Board will approve a DSM plan for the following year(s). The original plan may need to be revised in a Compliance Filing process. The Board will then order the plan to be put into effect pending approval of billing adjustments which will recover the costs associated with the DSM plan. At the same time the Board will approve the previous year's participation allocations, program expenditures and energy savings amounts. These activities should be concluded by the end of May of each year.

The DSM participation allocations, program expenditures and energy savings targets provided by the Administrator for the upcoming year will be used in NSPI's test year load forecasts, including for use in Fuel Adjustment Mechanism processes. It will be the basis of calculations for the DSM-related bill adjustments for each customer class. The proposed bill adjustments will be filed with the UARB no later than October 1 of each year. The Board will then follow a regulatory process leading to approval of the bill adjustments. By December 1 of each year, the Board will order the approved adjustments to be effective on January 1 of the following year.

This is essentially the process that is anticipated for 2009. In this Application NSPI has filed for Board approval of the proposed DSM program plan for 2010. Once an Order approving the plan, the cost allocation methodology and the Rider has been issued by the Board, NSPI will, in conjunction with its 2010 load forecast, be able to determine the DSM bill adjustments for each customer class. These will be submitted for Board approval by October 1, 2009 for implementation beginning on January 1, 2010.

6.0 CONCLUSION

DSM programs that help customers conserve energy are successfully underway in Nova Scotia. NSPI is pleased that there is support for the Company's approach to the allocation of DSM program costs as proposed in this filing. The Company is prepared to work with the independent Administrator to keep DSM programs on track in the future. To support continued DSM performance, NSPI respectfully requests Board approval of:

1. The 2010 DSM Programming Plan
2. The proposed approach regarding allocation of DSM program per Appendix G
3. The DSM Cost Recovery Rider (the Rider) which includes program and lost contribution to fixed costs to be recovered via electric bills
4. Recovery of DSM costs using the Rider

NSPI seeks the Board's confirmation that the PDWG will continue in its role until the new DSM Administrator is established.

The proposed plan is reasonable and aligns with DSM targets filed with the UARB in 2008. The proposal is fair to customers and to the utility in respect to the allocation and recovery of DSM costs. Approval of the DSM Plan for 2010 together with prospective and timely recovery of DSM expenditures will contribute to the success of electric DSM in Nova Scotia and help to ensure that the associated environmental and cost benefits envisioned in the IRP are achieved.

Appendix A

Final Report
Stakeholder Consultation Process for an Administrative Model for DSM Delivery in Nova Scotia

STAKEHOLDER CONSULTATION PROCESS FOR AN ADMINISTRATIVE MODEL FOR DSM DELIVERY IN NOVA SCOTIA

FINAL REPORT

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EXECUTIVE SUMMARY

The Faculty of Management at Dalhousie University was requested by Conserve Nova Scotia to prepare a proposal for a stakeholder consultation process for determining optimum designs for administration of electricity demand side management in the Province of Nova Scotia. The proposed brief was:

- **Establish a five stage stakeholder consultation process**
- **Provide relevant information to stakeholders on the variety of DSM administration models currently being used (including their strengths and weaknesses, key factors that contributed to their use in a particular jurisdiction, their suitability for use in the NS situation, etc)**
- **Attempt to secure a consensus (not necessarily unanimity) on the recommended administrative model(s)**
- **If no consensus is achievable on one model, then put forward administrative models that have significant stakeholder support identifying the strengths and weaknesses of each in the Nova Scotia context**
- **Identify the regulatory/legislative implications of the model(s) presented**

This report describes i) how the process unfolded; ii) the principal outcomes of the process; and iii) recommendations for the Government of Nova Scotia on steps necessary to implement the recommendations.

We recommend that the Government of Nova Scotia establish an independent 'third party' model of Electricity Demand Side Management Administration which we are characterising as a **Performance–Based Independent Efficiency Agency.** We suggest that this Agency be regulated by the Utility and Review Board (UARB) under an amendment to legislation, and be created by an Act of the Provincial Legislature and be provisionally entitled the **Nova Scotia Electricity Efficiency Agency.**[1]

The key characteristics of the entity are:

- **The Agency should be an Independent Multi-Purpose Entity (eg. a not-for-profit company created by legislation with all shares held by the Province of Nova Scotia)**
- **The Board of the Agency should be appointed by the UARB on merit according to pre-determined criteria and a transparent recruitment process (advised by an Interim Steering Committee)**
- **The Agency will have clear performance targets and management will have incentives to perform**
- **There will be regular independent performance audits against targets conducted by an independent auditor**
- **There should be a formal review before renewal of mandate through a Performance Review Mechanism (within a maximum period of three years)**
- **All funders and users of the Agency's programs should be involved and served in an accountable and transparent manner**

[1] We also offer the possibility to Government that - for reasons of longer term cost-effectiveness and synergy - consideration be given to leaving open the option of the Agency one day being renamed the Nova Scotia **Energy** Efficiency Agency and for it to become a 'one stop shop' for administration of multi-fuel efficiency measures. This would of course be subject to renewal of mandate with appropriate regulatory oversight and stakeholder involvement in design.

- **There should be secure funding**
- **The power utility should be a key partner on program branding and other activities including program delivery (should it decide to compete to provide such services)**
- **The Agency should be flexible enough to evolve its mandate and scope of activities according to public policy and other needs over time.**

We do not recommend consideration of alternative models at the present time.

DESCRIPTION OF PROCESS

Following a provisional meeting with officials of Conserve Nova Scotia and the Department of Energy on 19th December 2007, Dalhousie University prepared and submitted a proposal to conduct a stakeholder consultation process for determining optimum designs for administration of electricity demand side management in the Province of Nova Scotia. The proposal is attached as Appendix 1 to this document and was submitted 30th January 2008.

Potential stakeholders were identified through discussions with readily identified actors followed by telephone and email outreach to those stakeholders and further elicitation of names of potential stakeholders. Mid-way through the process a public advertisement was placed in the Chronicle Herald newspaper to further identify individuals and organisations that might wish to participate in consultations.

Three meetings were held with stakeholders between February 22nd and April 4th, and up to 40 stakeholders and their representatives attended on each occasion. In addition, four rounds of telephone and email outreach were conducted (one before each meeting) in order to ascertain views that stakeholders might prefer to express privately (see Appendix 4 for questionnaires). Finally, some stakeholder groups sent in letters and other communications that summarised their perspectives.

The PowerPoint presentations for each stakeholder meeting and the stakeholder outreach questionnaires are provided in Appendix 5.

Prior to the first meeting of stakeholders a paper entitled ***Overview of Administrative Models for Electricity DSM*** was circulated to attendees and non-attendees in order to try and clarify definitions and characteristics of the available models. This paper was drafted by our independent expert consultants and the final version of the document is presented in Appendix 2.[2]

Preparation for the first meeting of the stakeholders (February 22nd) invited the following input from stakeholders:

- **Identify any options that you believe may have been omitted;**
- **Comment on the list of potential advantages and disadvantages identified for each identified option;**
- **Suggest amendments to the working document that may assist in reaching consensus on definitions, descriptions and potential advantages and disadvantages identified.**

A strong majority of stakeholders who responded (12 of 13) believed the ***Overview*** paper "captured the main options for electricity demand side management". Nearly as strong a majority (11 of 13) believed "fairly captured the potential advantages and disadvantages identified for each identified option".

The first meeting of stakeholders (February 22nd) had the following objectives

- **Discuss and try to achieve consensus on the 'four options' and their potential advantages and disadvantages**
- **Discuss and prioritise the key principles that will drive our recommendation of a preferred administrative option for Nova Scotia**

[2] The paper went through three drafts based on stakeholder feedback and review.

- **Discuss the process and timescale which will allow us to achieve consensus on a preferred option for Nova Scotia**

At the meeting on 22nd February we achieved these objectives, making suggested amendments to the ***Options*** paper, proposing a number of ***Principles for Success*** for the process, and agreeing the importance of convening an expert seminar on Electricity DSM as soon as that could be arranged.

The Principles for Success, as discussed and later summarized and amended with stakeholder input are set out below.

Principles for Success	Primary Objectives (in order of priority identified by NS stakeholders)	Subsidiary Objectives (also identified by NS stakeholders but with less consensus)
Accountability and oversight. There need to be 'crisp and clear' delineation of authority and responsibility between the delivery agents and the administrator.	1. The DSM administrator is accountable for results/performance 2. Credible measurement - ability to monitor/ change/evaluate 3. Clear decision making structure (who makes the final decision) 4. No conflict of interest (convergence of interest)	Need for clearly defined roles and mission, administrator must be a trusted point of contact, chosen model must have broad stakeholder support and communicate effectively with stakeholders
Administrator effectiveness: fast and market responsive decision-making	1. Flexibility to adapt to changing public policy 2. Flexibility for program design 3. Responsiveness to long range planning 4. Builds implementation infrastructure (relates to human resource capability)	Speed of implementation, ability to move quickly (there is an urgency for action/program implementation and delivery), nimbleness, learn from mistakes/successes of others
Compatibility with public policy goals: avoidance of unhelpful politics – eg. pressure to deliver funding to constituencies, rather than to acquire cost-effective energy savings	1. Maximizing contribution to achieve the economic, social and environmental goals – transparency was also named as a top priority 2. Must be in context of province's sustainability act 3. Equity component – participation for low income – Who's paying, how much? And who's benefiting? 4. Non–bureaucratic and entrepreneurial that encourages competitive and innovative solutions	Represent everyone
Secure funding allocation: avoidance of misuse of funds for other budgetary purposes.	1. Results oriented versus spending oriented 2. Cost effective allocation 3. Predictable and dependable funding sources/multi-year	

On 26th March a one day expert seminar was convened to explore in more detail the possible advantages and disadvantages of the different models for DSM Administration in the Nova Scotia context. Preparation for the meeting invited stakeholders to offer final comments on the ***Options*** paper and prioritise the ***Principles for Success*** (captured in the above table).

The expert seminar received presentations from five perspectives. Each presenter was asked to help Nova Scotia stakeholders understand the advantages and disadvantages of their models with respect to the ***Principles for Success.*** The briefing provided to speakers is reproduced in Appendix 3.

The expert presenters for each option were as follows[3]:

- **Third Party Administration**
  - **Tom Foley (Energy Trust of Oregon)**
- **Efficiency Utility Administration**
  - **Blair Hamilton (Vermont Energy Investment Corp)**
- **Utility Administration with Regulatory Oversight**
  - **Tim Stout (National Grid USA)**
- **Government Administration**
  - **Elizabeth Weir (Efficiency New Brunswick)**
- **Utility Administration with Stakeholder Advisory Boards**
  - **Michael Stoddard (Environment Northeast)**

During the seminar our experts devoted equal time to presentations and questions, giving stakeholders every opportunity to explore the possible risks and benefits of these models as they might be applied in Nova Scotia. Stakeholders were also asked to note and submit particular comments on risks and benefits from their perspectives immediately after the session or later.

On April 4th the Dean of Management of Dalhousie University presented back to stakeholders his recommended option for the Electricity Demand Side Management in Nova Scotia and invited reactions to the recommendation. He recommended that the Government of Nova Scotia establish an independent 'third party' model of Electricity Demand Side Management Administration which he characterised as a **Performance–Based Independent Efficiency Agency.**

The decision criteria applied in making the recommendation were summarized as:

- **Consistency with Principles for Success**
  - ***Accountability and Oversight***
  - ***Administrator Effectiveness***
  - ***Compatibility with Public Policy Goals***
  - ***Secure Funding Allocation***
- **Maximise Speed - Minimise Risk**
- **Maximise Stakeholder Consensus - Minimise Divisiveness**
- **Accountability to funders (ratepayer versus taxpayer)**

[3] Subject to copyright and agreement of the presenters, the PowerPoint presentations from this session may be made available to interested parties.

ATTITUDES OF STAKEHOLDERS TO PROCESS

Throughout the process of stakeholder consultation, the Dalhousie University team carefully tracked stakeholder attitudes both to the offered options and to the process itself. At the first stakeholder meeting we offered the following 'rules of the game' in order to try to ensure a common vision for the process and its outcome:

- **Keep eyes on the prize**
  - **Best possible result for the people and the environment in Nova Scotia**
  - **Maximise contribution to achievement of Provincial economic, social and environmental goals**
- **Keep an open mind**
  - **Listen and inquire**
  - **Avoid assumptions based on past (mis-) understandings**
  - **Remember that not all stakeholders are in the room**
- **Promote consensus and win-win outcomes**
  - **'both and' rather than 'either or' thinking**

Broadly speaking, these rules were observed in a good spirit, although they did come under strain towards the end of the process when certain stakeholder positions were being advanced with more vigour and persistence. This was perhaps understandable as the potential implications of the models became clearer for stakeholders and decision-time drew closer. This was reflected in a slight softening of trust in Dalhousie's facilitation and the Government of Nova Scotia's ability to respond effectively to final recommendations.

From before the first stakeholder meeting through to the run-up to the final stakeholder meeting stakeholders were asked the following question:

Based on what happened at the meeting on [date], on a scale of 1-5 where 1 = no trust and 5 = total trust, can you please tell me how much trust you place in Dalhousie University now to run a fair and objective consultation process?

Over the six weeks trust in Dalhousie's process went from a score of 5.0, to 4.4, to 3.9. Care should be taken when interpreting the data; sample sizes were relatively low (typically less than 15) and respondents were not identical each time. However, given the fact that the facilitation process was providing something of a 'lightning rod' for stakeholder concerns, the facilitators were happy that trust and confidence held up as well as it did.

Stakeholders were also asked:

Based on what happened at the meeting on [date] on a scale of 1-5 where 1 = no trust and 5 = total trust, can you please tell me how much trust you are willing to place now in the Government of Nova Scotia responding effectively to the recommendations of the consultation process?

Over the six weeks trust in the Government's ability to respond effectively went from a score of 3.5, to 3.3, to 2.7. Again, care should be taken in interpreting these data. Clearly stakeholders were keen to send a signal to the Government that they expect action and this question allowed them to send such a signal.

Finally, between the first and third meetings stakeholders were asked:

Based on what happened at the meeting on [date], where 1 = Much Less Optimistic and 5 = Much More Optimistic, are you now more or less optimistic that we will be able to make clear recommendations to the Province in a timely and consensus-based way?

Stakeholder opinion on this question went from 3.2 to 3.3, demonstrating perhaps that despite the signals being sent to the facilitators and to the Government, stakeholders were not discouraged by the unfolding of the process, although the level of optimism remained moderate.

ATTITUDES OF STAKEHOLDERS TO OPTIONS

Before each stakeholder meeting stakeholders were asked:

Based on what you learned at the meeting [date], on a scale of 1-5 where 1 = highly undesirable and 5 = highly desirable can you please comment on what you now think will work for Nova Scotia.

Again, we must note the care with which these data must be interpreted given the relatively low sample size and the variability in the sample. Nevertheless, as we can see below, the popularity of the different options remained remarkably stable throughout the process. Scores should be read from left to right with the most recent score on the left and the first score on the right.

Utility Administration			
► **Regulatory Oversight**	**2.0**	**(2.3)**	**(1.8)**
Utility Administration			
► **Stakeholder Board**	**2.1**	**(2.3)**	**(1.8)**
Government Administration			
► **New Brunswick Model**	**2.6**	**(2.70**	**(2.4)**
Hybrid	**n/a**	**(n/a)**	**(3.7)**
Efficiency Utility			
► **Vermont New Model**	**4.0**	**(3.6)**	**(n/a)**
Third Party Administration			
► **Oregon Model**	**4.2**	**(3.9)**	**(3.7)**

We can summarise these data as follows: i) the Utility Administrator option is generally not favoured by stakeholders; ii) the Government Administrator option is generally not favoured by stakeholders although it is supported strongly by some of the industrial stakeholders; iii) the Hybrid Administrator option is generally not favoured by stakeholders and was in any case eliminated from the options through discussion; iv) the Efficiency Utility Administrator option merits both strong support and strong (if more minor) opposition; and v) the Third Party Administrator option merits strongest and most consistent support among stakeholders, including among some of the industrial stakeholders.

RECOMMENDATION

Based on the foregoing analysis, the decision criteria[4] described earlier, and input from stakeholders at the third stakeholder meeting we constructed a table outlining the potential strengths and potential sources of risk for the four options where:

✓ = Potential Source of Risk (assuming early implementation)

✓✓ = Neutral (assuming early implementation)

✓✓✓ = Potential Strength (assuming early implementation)

CRITERION	UTILITY ADMINSTRATOR	GOVERNMENT ADMINISTRATOR	EFFICIENCY UTILITY ADMINISTRATOR	THIRD PARTY ADMINISTRATOR
ACCOUNTABILITY & OVERSIGHT	✓	✓	✓✓✓	✓✓
ADMINISTRATOR EFFECTIVENESS	✓✓	✓✓	✓✓	✓✓✓
COMPATIBILITY WITH PUBLIC POLICY GOALS	✓✓	✓✓	✓✓✓	✓✓✓
SECURE FUNDING ALLOCATION	✓✓	✓	✓✓✓	✓✓✓
MAXIMISE SPEED – MINIMISE RISK	✓✓	✓✓	✓	✓✓✓
MAXIMISE STAKEHOLDER CONSENSUS – MINIMISE DIVISIVENESS	✓	✓	✓✓	✓✓✓
ACCOUNTABILITY TO FUNDERS (RATEPAYERS PAY)	✓✓	✓✓	✓✓✓	✓✓✓
ACCOUNTABILITY TO FUNDERS (TAXPAYERS PAY)	✓	✓✓	✓✓	✓

The table is not intended to be anything other than impressionistic, but it does try to capture and summarise the overall picture from our analysis and the expressed opinions of stakeholders.

[4] See earlier Principles for Success table for details of criteria and sub-criteria

Based on the analysis we conclude that with goodwill and appropriate speed of decision-making:

- **All options *could* work;**
- **All options *could* be up and running by June 2009 with varying levels of complication;**
- **Three options would risk divisiveness if we moved to them *now*, but all could (in theory) be considered in the future when capacity and experience are more established;**
- **Thus we believe that only one option would merit significant (if not total) consensus today *provided key safeguards are in place.***

Thus we recommend a Third Party Administrator model that we will refer henceforth to as a **Performance–Based Independent Efficiency Agency.** We recommend this model regardless of source of funding, but we believe that ratepayer funding with direct mechanisms of stakeholder involvement and oversight for different classes of customer is likely to result in greater engagement with programs and thus greater accountability for performance.

Below we depict the main elements of the model as we are recommending it (Figure 1).

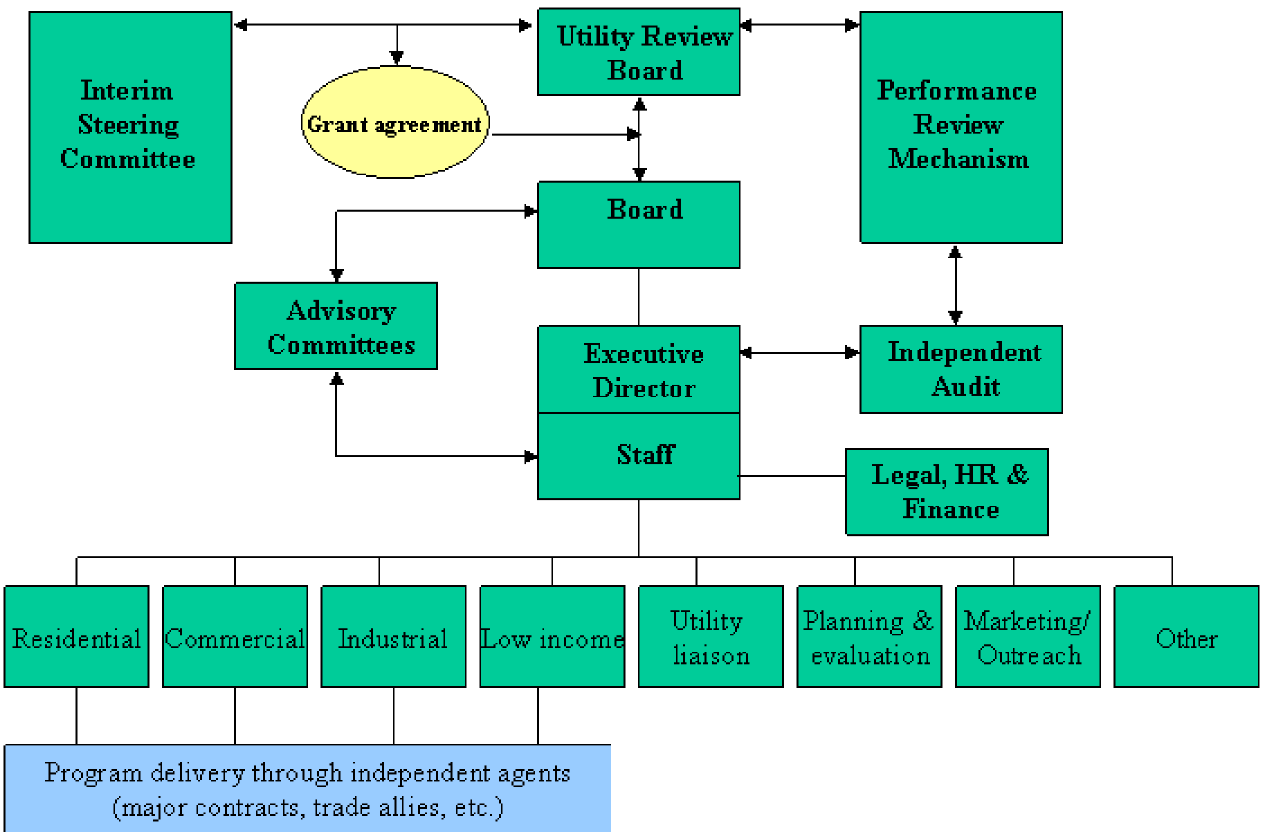

Figure 1 Main Organizational Elements of the Proposed Nova Scotia Electricity Efficiency Agency. NB this model has been modified slightly from that originally presented to stakeholders based on the advice of our legal experts.

HOW THE MODEL ADDRESSES IDENTIFIED PRINCIPLES FOR SUCCESS

In the course of the consultation process stakeholders identified a hierarchy of guiding principles deemed necessary for ensuring the success of Demand Side Administration in Nova Scotia. These principles were carefully considered in the final recommendations of the model presented here and are directly addressed in this section. The table of Principles for Success - as identified by stakeholders – was described earlier. We deal with each category in turn.

Accountability and Oversight

The primary objectives under this Principle for Success were:

- The DSM Administrator is accountable for results/performance
- Credible measurement - ability to monitor/ change/evaluate
- Clear decision making structure (who makes the final decision)
- No conflict of interest (convergence of interest)

It is clear that many stakeholders are sceptical about any structure and mandate that does not include strong accountability with appropriate performance metrics. For this reason, several stakeholders expressed a strong preference for competitive solicitation for the role of Administrator through an RFP process. Such a process was ruled out on several grounds: possible time delays, costs, complexity and a lack of critical mass of expertise in the province to mount multiple competitive bids. In order to compensate for this we envisage the Agency being run like a business with targets explicitly agreed at the level of the UARB on a (minimum) tri-annual basis. These targets would be contractually assigned to the Board of Directors of the new Agency. The Board would then organize staff and contractors to deliver the required results.

We do not believe that it is appropriate, at least initially, to impose under-performance penalties on a non-profit public agency. However with the right Board of Directors recruiting the right Executive Director, and with staff with receiving the right performance management, compensation and incentives, we believe that the enterprise will have the appropriate motivation to succeed. The cost of failure for the Board would be removal of mandate within three years. The cost of failure for the Executive Director and staff would be loss of position.

Furthermore, actual delivery will be delegated in large part to private sector contractors, who would receive incentives and penalties, benchmarked against quantifiable performance targets and contractual metrics.

It is envisaged that the Board will develop targets for each sector, with specific targets being devoted to low income group, residential, commercial and industrial users. Based on our stakeholder consultation process, special care will need to be taken over low income group and industrial targets so that benefits within those (and other sectors) are fairly shared (over time) with contributors in each sector.

We propose an independent audit function for the Agency which would make annual reports to the Agency, the public and the UARB. The Auditor will be engaged through a Performance Review Mechanism (which could be put in place by an *ad hoc* advisory committee established by the UARB) in order to ensure complete impartiality. In addition the Agency will naturally have its own internal audit and reporting function to provide program by program assessments of measurable outcomes. The scope of the PRM may vary over time according to perceived needs and issues identified by the UARB or other parties eg. the Government of Nova Scotia.[5]

A number of stakeholders expressed the concern that Nova Scotia is a jurisdiction with a history of political interference in staffing processes, and that this might be perpetuated in the Agency. For this reason we believe that the selection of the initial Board should be carried out by an advisory committee appointed by the UARB which will be called the Interim Steering Committee. The ISC will conduct a transparent merit-based recruitment process, including the possible use of an executive recruitment firm, to identify Board members who will be selected according to clear criteria. There should be no requirement that either the ISC or the eventual Board be representative of specific financial or program interests in order that they may single-mindedly discharge their obligations to the Agency according to their targets and agreed *modus operandi*. In this way conflicts of interest, or indeed any appearances of conflict, will also be avoided. Thus we do not envisage that the ISC will be a representative group in the sense that it should reflect the separate interests of individual user groups hitherto identified. However it will be important for the Government of Nova Scotia and the UARB to appoint individuals to the ISC who are of high professional and expert standing[6] and who also maintain strong sensitivity to stakeholder interests. This will allow for the continued building the trust and goodwill established in the process to date.

It is also envisaged that the ISC will agree on recommended policies pertaining to i) the role and mandate of the Board; ii) the skills and capabilities envisioned for the Executive Director; iii) reward and incentive structures; and a number of other factors deemed essential to the smooth running of the Agency in its first months. These recommendations will be forwarded to the new Board on its inception. It will then be at the Board's discretion to accept or modify these policy recommendations.

Once established, the Board will have complete fiduciary responsibility for the Agency and be wholly responsible for its strategic direction. The Board will also appoint the Executive Director (effectively the Chief Executive Officer of the Agency) and will continually review and monitor the overall performance of the entity.

Administrator Effectiveness

The primary objectives under this Principle for Success were:

- Flexibility to adapt to changing public policy
- Flexibility for program design
- Responsiveness to long range planning
- Builds implementation infrastructure (relates to human resource capability)

[5] For example, if there is a high level of trust in the Agency's own auditing and reporting procedures, it may not be necessary to commission anything other than verification type procedures.
[6] As a minimum, these individuals must have collective experience of Nova Scotia law and public policy, the functioning of the electricity industry, performance-based management, and corporate governance. The ISC as a whole must have business acumen and should also be able to demonstrate sensitivity to social, environmental and economic interests.

We believe that these objectives should be built into the mandate of the Board of the Agency by the ISC.

We further believe that the proposed corporate structure allows for maximum administrative flexibility to adapt to changing public policy, evolving program design and maturing program delivery expertise. A lean initial staff will allow maximum flexibility to determine which functions should be retained in house long term and which should be contracted out. In a highly competitive labour market for the particular expertise sought, the proposed model allows the Agency to pay market based compensation and performance-based incentives in order to attract the highest qualified staff. Staffing patterns can of course evolve efficiently if mandates expand (eg. in any future all-fuels or renewables programming scenarios).

Being able to plan for investments over the long term, starting with a rolling three year period seems to us to be essential if the Agency is to achieve early momentum and mobilize sufficient investments. However, this factor is in slight tension with the desire to maintain accountability and (in the event of under-performance) to end the mandate of the Board and Agency within three years of inception eg. if it fails to meet targets. For this reason, again we will defer to the wisdom of the ISC to design the initial mission and mandate of the Board and Agency in such a way that maximum performance over the long term does not come at the cost of unreasonable risk in the short term.

We were also persuaded by the strong arguments of Efficiency New Brunswick and many Nova Scotia stakeholders that this Agency should endeavour – over time – to explore synergies with other energy savings schemes and even to accept responsibility for such schemes if that is deemed appropriate by the Government of Nova Scotia and relevant stakeholders. In this way we might imagine that one day the Electricity Efficiency Agency might become the **Energy** Efficiency Agency, thereby creating the kind of 'one stop shop' for all energy savings schemes that New Brunswick, Oregon, and Vermont are attempting to become.

Compatibility with Public Policy Goals

The primary objectives under this Principle for Success were:

- Maximizing contribution to achieve the economic, social and environmental goals – transparency was also named as a top priority
- Must be in context of province's Environmental Goals and Sustainable Prosperity Act
- Equity component – participation for low income – Who is paying, how much? And who is benefiting?
- Non–bureaucratic and entrepreneurial that encourages competitive and innovative solutions

As noted above, we expect the Agency to be run like a business. But it will be a business with an explicit public purpose, hardwired into its mandate which will be to achieve:

1) **The best possible result for the people and the environment in Nova Scotia; and**
2) **Maximise its contribution to the achievement of Provincial economic, social and environmental goals**

The three-year targets of the Agency will undoubtedly be set in the full understanding that they must contribute to the provincial sustainability targets whilst maintaining equity between sectors and making special provision for those on low income.

In those jurisdictions that we have explored that have implemented DSM successfully, special arrangements for low income customers have been made and effectively implemented.

In terms of accountability to particular sectoral interests in spending, in Oregon there is an 80% rule of thumb which implies that at least 80 cents on every dollar invested by and allocated for a sector is returned through investments in that sector within the financial year. In Oregon, the funding and allocation sums are 'trued up' over time to ensure minimal cross-subsidisation but maximum synergies where these are to be gained. We believe this sort of approach can certainly work in Nova Scotia very well and assuage most concerns that efficiency can work for everyone and benefit everyone a) by avoiding more expensive base load generation costs; b) by ensuring transparency and competition for efficiency savings at the implementation level; and c) by encouraging entrepreneurial and creative activity, both solicited and unsolicited.

In addition to these practical matters, the Agency will be authorized by the Provincial Legislature; and it will have independent audits through the Performance Review Mechanism. At the program implementation level, Stakeholder Advisory Committees will act as real-time checks and balances on the programming, the efficiency of programs and the contribution being made to the public purpose.

Secure Funding Allocation

The primary objectives under this Principle for Success were:

- Results oriented versus spending oriented
- Cost effective allocation
- Predictable and dependable funding sources/multi-year

The important point here is that the transfer of funds to the administrator – from whatever source – must be irreversible[7] in order to build stable program delivery and secure the confidence of program clients and delivery agents. And in order to deliver effective programs that acquire a stream of savings, the Administrator must be able to make multiyear funding commitments to both program clients and delivery agents.

As noted above the targets established by the Interim Steering Committee and adopted by the UARB will determine the agenda for the Agency for the period 2009 to 2012 (the first three years of operation). Every decision taken by the Board, the Executive Director and the staff, advised by the Stakeholder Advisory Committees will be in service of meeting these targets.

We expect that funding will come from electricity users, as they have the most to gain from efficiency investments and the most to lose if more expensive energy supply options are required because efficiency targets are not met. Least cost planning exercises regularly identify electric energy efficiency as the cheapest and most environmentally beneficial option to pursue to meet future load requirements. However, in the event that the Provincial Government wishes instead to raise taxes to pay for the Agency's investments, presumably with a view to introducing new formulae for future electricity rate setting through the UARB because of this new 'subsidy' from the taxpayer, we would still recommend the administrative model described here. We would then also suggest additional and special safeguards be put in place to avoid raiding of surplus funds and more direct accountabilities to Ministers and Deputy Ministers whose responsibilities include taxation and spending policies.

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[7] Except for obvious circumstances of egregious maladministration, if such was identified through the independent assessments of the Performance Review Mechanism. Under these circumstances we would expect the assets of the Agency to be frozen for possible future transfer to another body.

Under the model proposed here, funded by ratepayers, with the provisions we have recommended, we have attempted to minimize the danger of budget raids or political interference. And again, with the structure we recommend, neither do we see any impediment to making multi-year commitments and managing investments across rolling three year cycles.

We have already described how the Agency might develop with an initial three year mandate, indefinitely renewable, subject to performance, independent audit, and (minimum) three year full performance reviews. We have also suggested that should there be a will to evolve the model over time for reasons of greater efficiency or potentially better results (eg. to an Energy Efficiency Utility or to another model) that would be entirely feasible under the structure we propose. It is not our intention here to assume this will happen, as we expect the new Agency to succeed in its proposed format. However, we do believe that the Government of Nova Scotia should keep an open mind on opportunities for optimization of the model if they emerge. And of course we have left open the option of a move to multi-fuel efficiency administration if that was deemed desirable; subject to appropriate stakeholder consultation.[8]

Whatever administrative option is in play over time, we believe that a long term commitment should be made to funding the activities of the administrator – most likely through a systems benefit charge or separately set public purpose charges for each sector. It would be typical to lock in such commitments for a minimum of 10 years in order to avoid creating uncertainty in the contractors and energy efficiency consultants building their businesses on the implementation of DSM.

[8] Only electricity supply stakeholders were consulted in this process.

SETTING UP THE AGENCY

In order for the Agency to be fully functional by June 2009, some early activity will be required.

Legislative enablement will be necessary. In addition, the Interim Steering Committee (ISC) will need to be appointed by the UARB in order to put in train selection processes for the Board and draft policies and targets for the new Agency.

The ISC will also have to advise the UARB on the contract which it will need to mandate the Agency so that the UARB has the powers to:

1) Issue a Grant Agreement which establishes the Agency's mandate
2) Set minimum performance targets (through the Grant Agreement). These are suggested to include at a minimum: MW savings per year, minimum spending on low income customers, equitable spending between other customer classes, spending limitations on administration and marketing (eg. less than or equal to 7% and 4% respectively). These performance standards should be developed in consultation with stakeholders.
3) Appoint a Board of Directors
4) Design the annual audit requirement and the structure and mandate of the Performance Review Mechanism.
5) Require quarterly and annual reports.
6) Set policy on performance-based incentive structures (to be set out in the Grant Agreement). For example, achieving and exceeding targets can be incentivized via a bonus structure to the ED and the staff. Bonuses can be set at different levels based on level of targets achieved (eg. 90, 100, 110 and 120%). The bonus standards should be reviewed through the Performance Review Mechanism every three years and re-established in line with new goals and targets. Annual audits will be required before bonuses are paid. Performance-based incentives should also be applied to program delivery agents to encourage/reward the meeting and exceeding of targets.
7) Initiate an early Performance Review if deemed important.
8) Terminate the mandate of the Agency eg. following the issue of appropriate prior warnings.

Board of Directors

It is envisaged that the Board of the Agency will comprise people of impeccable character, managerial and public experience, with an interest in energy efficiency, but not a financial stake in those contractors and agents implementing energy efficiency. Board members should not represent any particular constituency. Administrators in other jurisdictions have sought out individuals with backgrounds in business and public boards, and a commitment to energy efficiency and environmental objectives. The Board's primary role is to focus on policy and strategy, setting goals consistent with UARB targets, fiduciary responsibility, endorsement of investments in implementation of programs, and selection of the Executive Director.

As noted above, board members should be *appointed* by the UARB, based on an open public recruitment/application process overseen (in the first instance) by the Interim Steering Committee. Subsequent vacancies should be filled by the board under processes of good corporate governance, with appropriate notification to and ratification by the UARB.

Executive Director and Staff

Executive Director

As soon as the Board is selected, a search committee (Board sub-committee), perhaps serviced by an executive search firm, should conduct a recruitment and interview process and appoint the Executive Director. Ratification of the Executive Director appointment could be done by the UARB if deemed useful.

Staffing

Based on the experience of similar start-up efforts, the initial staff of the organization might include:

- Program Staff, including: a Residential Sector Manager; a Commercial Industrial Sector Manager; and a Low Income Sector Manager (could be combined with Residential); Staff Engineer(s).

- Administrative Staff, including: an Administrative/Personnel Manager; Fiscal Officer; Counsel (could be outside counsel initially); a Marketing Manager (could be an outside contractor); a Data Collection and Reporting Manager; (also could be contracted out).

- Evaluation Manager

Program Sector Manager[9] duties typically include:

- Design programs, in consultation with Program Stakeholder Advisory Committees (PSACs)
- Establish program terms and conditions; set consumer incentives
- Draft RFPs for program implementation, including performance metrics (and accompanying penalties and rewards)
- Administer implementation contracts

Acting on staff/PSAC recommendations, the Board sets performance metrics for prospective implementation contractors; which are then reflected in RFPs and subsequent contracts.

Program Stakeholder Advisory Committees

Stakeholder Advisory Committees are the interface between broad customer groups and constituencies and the staff and Board, advising staff and vetting new program ideas and modifications before presentation to the Board.

The Board selects the Committees which in other jurisdictions typically consist of representatives of such significant stakeholders as:

[9] A lean Program Sector Manager model allows for outsourced program implementation and delivery, but retains the option to bring service delivery in house as local expertise grows.

- Customer groups (eg. industrial, business, residential, low-income, municipal, etc.)
- Public interest representation (eg. environmental groups, sustainability organizations, etc.)
- Entities with an interest/complementary charters (eg. Department of Energy/Conserve Nova Scotia, ratepayer advocate, Nova Scotia Power, etc.)
- Trade allies (eg. HVAC contractors, electrical contractors, energy service companies, manufacturer's reps., etc.)
- Professional allies (eg. architects, engineers, lighting designers, etc.)
- Representatives of the Board

The Committees provide input to staff on program design, goals, etc. Proposals advanced for board approval with joint Council/staff recommendation. Council consensus should be sought, but a majority vote moves proposals forward. A minority report to the Board is permitted.

PROGRAM DELIVERY

Programs designed by staff, with stakeholder support and Board approval, are delivered by private contractors selected by competitive procurement. The Utility may also play an active role in bidding for such opportunities.

For procurement purposes, programs are clustered into logical market sectors for service procurement. For example, Residential New Construction and Residential Retrofit can be logically delivered by separate contractors; New Commercial Construction and Commercial Retrofit could be delivered by the same contractor.

Contractors operate under performance metrics; for which they are rewarded if they exceed and penalized if they fail. Some metrics may flow through from broad metrics assigned to the Agency (a share of kWh savings, marketing and overhead cost constraints, for example). Others may be unique to the sector or contract (percentage of new construction market captured, etc.) This segmented delivery model allows the Agency to maximize the benefits of outsourcing – selecting the best contractors for each discrete market area, while minimizing risks – a non-performing contractor can be easily dismissed, with minimum disruption to the overall program effort.

The model also reserves the choice to bring certain elements of consolidated service delivery in-house at future, if desired and as local experience and expertise grows.

LEGISLATIVE AND REGULATORY REQUIREMENTS[10]

Legislative and regulatory requirements will depend to some extent on specific design details that are not yet developed. Therefore the perspectives that follow are somewhat preliminary. It is hoped nevertheless that they establish a starting point upon which to build as the proposed model undergoes further elaboration.

The "Principle for Success" of highest relevance to this part of the discussion is "Accountability and Oversight". Just as success demands a "crisp and clear" delineation of responsibility between the administrator and the delivery agents, it will demand a "crisp and clear" relationship between the administrator and its regulator(s) and between and among regulatory processes. The regulatory and legislated oversight process must effectively ensure and reinforce accountability for performance while leaving responsibility for performance with the administrator.

Constitution of the Agency

From a legislative standpoint, the core of the proposed model will be the regulatory relationship between the Utility and Review Board (the UARB) and the Nova Scotia Electricity Efficiency Agency (the Agency).

Recognizing that the Agency must in the end be responsible for the plan it develops and implements to achieve the targets that are given to it, the relationship between the UARB and the Agency will have the following components when the Agency is in steady state and fully operational: development of the DSM plan (particularly of DSM targets) by the Agency (with significant stakeholder input); submission of the plan for approval to the UARB; review and approval of the plan by the UARB through the regulatory hearing process (inclusive of broad stakeholder participation); implementation of the plan by the Agency; periodic evaluation of performance against approved targets by the UARB through the mechanisms laid out either in legislation or in UARB policies, including those providing for ongoing stakeholder participation; and the making of appropriate rulings by the UARB for the purpose of further target setting or revision and (in the event of failure) rulings that may include reallocation of DSM responsibility to an alternative agency or (in the event of a move toward multi-fuel responsibilities) broadening the mandate of the Agency.

For this relationship to be effectively established in law, the Agency should ideally be a distinct legal entity from the UARB. That is, it should not be or be seen to be the creation of the UARB. Otherwise, the UARB would be the *de facto* provider or manager of DSM programs, not the regulator of the delivery of them. Accountability will be less meaningful than would otherwise be the case.

The strongest mechanism for establishing this necessary relationship of institutional differentiation is legislation that constitutes the Agency as a distinct statutory entity. This could be done by amendment to the *Public Utilities Act* or under stand alone legislation that was linked to the *Public Utilities Act*. Other options that might be considered (such as creation of the Agency under a contract with the UARB or through incorporation as a not-for-profit society under the *Societies Act*) would not provide the necessary level of institutional differentiation that is fundamental if the Agency is to be subject to meaningful external oversight.

Giving the Agency a statutory foundation will also have the benefit of mitigating any concerns that potential delivery agents might have about entering into contractual relationships with the Agency,

[10] This section is contributed by William Lahey, with the assistance of Meinhard Doelle, both of Dalhousie Law School.

given the newness of the DSM program in Nova Scotia and the performance conditional nature of the Agency's continuing involvement.

Administrative Mandate of the Agency

It is key to the proposed model that the Agency does not "own" the DSM mandate. Instead, it is critical that the Agency's continuation as the provider of the DSM program be contingent upon successful performance, measured against targets and programs that are aligned with the goals found in the *Environmental Goals and Sustainable Prosperity Act*, and that are developed in consultation with stakeholders.

This necessary contingency may seem in tension with the view that the Agency should be constituted as a distinct statutory entity. This tension can be resolved by careful design of the legislation that is used to establish the Agency. Such legislation should confer standard (generic) statutory powers on the Agency and deal with its basic internal governance and administrative structures, including internal accountability structures and processes. It should not however, deal in detail with the DSM mandate of the Agency, except to the extent necessary to ensure that it has ample jurisdiction in general terms to undertake such DSM activities and responsibilities (if any) as are conferred upon it through a contract with the UARB. In other words, the legislation should leave the details of the DSM mandate of the Agency (and of other DSM providers who may take the place of the Agency) to the contractual instruments that, under the proposed model, are envisaged as the mechanism that the UARB will primarily rely upon to confer responsibility for DSM programs on the Agency (or on any alternative DSM provider). It will however, be useful to have a clear statement of principle in the legislation that the Agency will be responsible for achieving performance measured against targets that align with the goals set out in the *Environmental Goals and Sustainable Prosperity Act* and that are set through a participatory regulatory process.

The contracts that are to define the detailed mandate of the Agency will have to be authorized by legislation. This will have to be done with considerable care. On the one hand, the statutory foundation for such contracts needs to be broad and flexible enough to evolve with time and experience. It needs to authorize contractual relationships that are "business like" in their emphasis on results instead of compliance. On the other hand, the statutory authority for DSM contracting needs to unquestionably enable the UARB to perform the regulatory role that it must play if it is to effectively protect the specific interests of ratepayers and the broader interest of the public in efficient and effective DSM programming.

In effect, the legislative jurisdiction of the UARB and of the Agency to define the DSM mandate of the Agency through regulatory contract must be broad enough to encompass all the matters on which the UARB will receive advice relevant to the mandating of the Agency from the Interim Steering Committee. These are listed in the section of the report entitled "Setting UpThe Agency", above.

Legislative Mandate of the UARB

Under existing legislation, the UARB has no statutory authority to regulate a demand side management agency that is not a regulated electrical utility. Indeed, the authority of the UARB to regulate demand side management activities, even when undertaken by a regulated electrical utility, is not as clear and as comprehensive as it might be.

Success of the proposed model (or of any model that depends upon UARB oversight) will require legislative amendments that give the UARB authority over a DSM regime that is linked to but distinct from its current mandate over the business of electricity generation and distribution. The linkage is critical for various reasons. One is to ensure ongoing alignment between DSM program design and performance with the obligations of the utility to maintain reliability standards that are regionally defined and enforced. More broadly, the mandate of the UARB in respect of DSM must be part of its larger mandate over integrated resource planning, which encompasses electricity supply and demand options and environmental requirements, including renewable energy portfolio requirements. In the design of the legislative changes that will be needed to give the UARB a broader DSM mandate, it will be critical to think through the relationship of this mandate to the current emphasis on secure electricity at lowest cost.

The specific functions that are envisaged by the proposed model and assigned to the UARB will have to be specifically authorized by new legislation. These functions include: taking advice on appointments from an Interim Steering Committee; making appointments to the Board of the Agency; entering into contracts with the Agency or other DSM administration; establishing and taking advice through the Performance Review Mechanism; conducting hearings and review processes in respect of DSM performance and related matters; and taking regulatory actions in respect of DSM, including the issuing of rulings or orders or the taking of other actions, such as contractual cancellation. Most fundamentally, the UARB will have to be given clear and comprehensive authority to oversee the funding of the Agency (and of the DSM program) through the rate setting process, picking up advice and stakeholder input (through the Interim Steering Committee and possibly other mechanisms) as funding moves from one regulatory process (rate review) to another (DSM program delivery).

Oversight and Accountability Framework

The proposed model contemplates the existence of a Performance Review Mechanism (the PRM) that receives input from and oversees an independent audit process of the Agency's performance. It contemplates the PRM being directly linked to the UARB, through the UARB's oversight role of the Agency.

These institutions and processes could be structured in a number of different ways. Different options would have different implications for legislation. Our recommended approach is to structure the PRM and the independent audit process as part of the UARB's regulatory process.

Under this approach, the PRM would be established as an advisory process for the UARB. This is relevant to the question of whether the PRM should be legislatively established (or prescribed) or whether legislation should instead leave the whole matter of ongoing audit and advice on DSM Agency performance to the UARB, at least as it relates to the external regulatory process. The latter is more consistent with existing UARB practice, under which the Board engages expert advisors as required to provide advice on major hearings, particularly those with a wider policy scope. It is also most consistent with the advisory status of the PRM and would provide the greater protection against the possibility of conflict or uncertainty over regulatory roles and responsibilities.

This would suggest a broad, flexible and discretionary legislative mandate that empowered the UARB to establish and maintain a performance review mechanism that could be structured (and restructured) by the UARB to ensure relevancy and responsiveness to the advisory needs of the UARB as they change over time.[11] UARB oversight of the functioning of the Agency's internal

[11] This distinction is similar to the distinction that is often drawn between 'quality control' and 'quality assurance' in a business setting, the latter being more concerned with ensuring the integrity of those managerial systems designed to meet overall goals rather than the specifics of data and measurements. In this respect, the PRM is a quality assurance mechanism that will audit and assure the integrity of the Agency's own internal audits and quality control mechanisms.

processes of audit and performance evaluation may help to keep responsibility for DSM delivery performance with the Agency and its stakeholders, where it properly belongs.

Further thought needs to be given to the linkages that might exist between the ongoing performance review process and stakeholder advisory committees that will be in place at the Agency level. We recommend deferring this discussion and more precise details of how the PRM will work to the Interim Steering Committee, once it is established, in consultation with the UARB.

The Interim Steering Committee

The Interim Steering Committee (the ISC) that is proposed would be tasked with related but quite different types of responsibilities. It would oversee a recruitment process for initial members of the Board of the Agency and provide these names to the UARB for formal appointment. It should be made clear that this is envisaged as an advisory function, as an approach that limited the UARB to confirming ISC decisions would be quite unusual and of understandable concern to the UARB. An approach that may be acceptable is one in which the UARB is limited to appointing from persons proposed by the ISC but free to refuse nominees.

A similar (but broader) role envisaged for the Interim Steering Committee is providing advice to the UARB on the targets that become the core of the mandate of the Agency once they are adopted by the UARB and incorporated into the contract that will define the mandate of the Agency. It appears that these recommended targets will be at the level of the DSM program as a whole and at the level of the particular sectors. It is contemplated in this area that the ISC will play a policy-making function in that the targets are expected to advance those found in the *Environmental Goals and Sustainable Prosperity Act*.

In both of the above roles, the ISC will be advisory to the UARB. It is however, also envisaged to have the responsibility of advising on the development of the legislation that will be needed to put the overall model into process. In this role, it is presumably envisaged that the ISC will be advisory to Government, through Conserve Nova Scotia, with the UARB also involved. In carrying out this role, linkages could usefully be built between the ISC process and the role of the Roundtable on Environmental Sustainability under the *Environmental Goals and Sustainable Prosperity Act*.

In all of its proposed functions, the ISC has the potential to be the bridge between the stakeholder consultations that have taken place and the process of elaboration and implementation that must now follow if the proposed model is to become functional by June of 2009. The ISC should therefore be established as quickly as possible, without waiting for legislative changes. Indeed, it is important to get the ISC formally constituted precisely so that it can provide advice on the legislative changes while ensuring broad stakeholder awareness of the legislative change process. Given the advisory nature of its responsibilities, the ISC should be able to begin its work in anticipation of the legislative changes that will be needed to enable the UARB to act on ISC advice on appointments and targets.

As it will be important for the UARB and the Agency to have a clean two-way relationship on mandate and performance against mandate, the ISC will not necessarily have a life beyond the inception of the Agency. However, the UARB will have the authority to strike similar committees or seek equivalent professional advice on mandate and performance, including the design and updating of PRM activities. Again, we recommend deferring this discussion and more precise details of how the PRM will work to the Interim Steering Committee, once it is established, in consultation with the UARB.

Observations on the Legislative Process

The above discussion deals at a general level with the legislative changes that will be needed to implement the proposed model for DSM administration. Equally important is the process that will be followed for making these changes and for defining them more precisely. Depending on how it is structured, the process can be an enabler or a barrier to the successful development and implementation of the proposed model. The need for action that is immediate enough to have the new system in place by June 2009 needs to be balanced against the continuing need for stakeholder involvement and the need for legislative changes that are precisely tailored to the policy objectives and regulatory and operational requirements, as informed by continuing dialogue and analysis. A process of legislative change that aims to do too much too quickly may not be able to achieve and maintain this balance. Conversely, a process of legislative change that leaves all of the legislative changes until the point at which all the questions have been answered would prevent success by June of 2009. Accordingly, thought should be given to a sequential approach to legislative change that is aligned with the sequence of activities that will have to be taken on the ground to get the Agency up and running, with the appropriate regulatory framework in place, by June 2009. Such an approach would start with the establishment of the ISC, with the process for recruiting members of the Board of the Agency and with the appointment of the successful candidates, with recruitment of an Executive Director and with the development of the targets that will become the core of the mandate of the Agency. Subsequent phases of the process will then be able to proceed with benefit of input from the Agency and with better knowledge as to the precise legislative changes that would be required or helpful in other and more technical areas.

RELATIONSHIP WITH THE UTILITY

Consistent with successful experience elsewhere, it is proposed that each Utility of a particular size should have an *ex officio* seat on the Agency Board for informational but not decision-making or voting purposes (as will pertain for the UARB). As noted earlier, the current electricity utility (NSP) may bid for program delivery services, in competition with, or collaboration with, other outside bidders.

In addition, it is envisaged that staff from the new Agency will work with NSP on future IRPs, and they will work with NSP to develop a marketing and outreach strategy[12]. It is expected that NSP will be encouraged to work with the Nova Scotia Electricity Efficiency Agency to help ensure the most appropriate programs are developing (i.e. provide energy consumption trends, etc.), and NSP will collect relevant charges from users and transfer them to the Agency on a monthly basis.

[12] We expect that any marketing and branding strategies developed by NSP, Conserve Nova Scotia and other parties in coming months will be of sufficiently high quality to be of value to the new Agency when it is established and that such brand equity will be shared in common by the new parties after inception, subject to appropriate IP agreements. However we do not wish to bind the decision-making of the new Agency in this regard as they will need to make their own decisions on these matters in due course.

MULTI-FUELS

Many stakeholders expressed the importance of moving beyond electricity energy efficiency to all fuels. Most agreed that the initial mandate of the administrator should focus on electricity DSM in the first instance but that there should be scope to move to other programming in time. As noted above, the one-stop shop approach of Efficiency New Brunswick, the Energy Trust of Oregon and the Vermont Energy Efficiency Corporation were seen as good approaches to adopt in Nova Scotia. To this end it is recommended that the mandate of the NS model be electricity efficiency initially but that would not preclude a future move to program delivery for renewable energy, fuel switching, and other mechanisms. Moreover the Agency would not be precluded from receiving funds from any source in the pursuit of its mandate. Again we recommend deferring this discussion and more precise details of how the mandate of the Agency may evolve to future processes of stakeholder consultation and policy-making by the Government of Nova Scotia.

APPENDIX 1

PROJECT PROPOSAL

STAKEHOLDER CONSULTATION PROCESS FOR AN ADMINISTRATIVE MODEL FOR DSM DELIVERY IN NOVA SCOTIA

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INTRODUCTION

As part of its Integrated Resource Plan, Nova Scotia Power (NSP) has been asked, among other things, to develop a Demand Side Management (DSM) plan for the electricity sector. That plan is being prepared through a collaborative process with stakeholders, which will be submitted to the Utility and Review Board (UARB) and reviewed in a public hearing. The DSM plan will consider many details: level of annual investment including potential ramp up, program details for all electricity sectors, how DSM program costs will be recovered in rates, and how the DSM program will be tracked and reported. Not addressed by the plan is the question of program administration. A number of stakeholders have expressed an interest in arrangements for DSM in the Province and it is proposed that a range of DSM administration models be considered.

This project establishes an independent stakeholder consultation process to thoroughly assess the various options for administration and accountability for an electricity DSM program in Nova Scotia. The project will identify the range of alternative administration models and weigh the pros and cons of each with stakeholders. The aim is to build consensus based on agreement of goals and a ranking for the preferred option(s). The project will identify how the preferred option(s) could be implemented in Nova Scotia and what would be the relative benefits and risks and regulatory and legislative implications of various options.

PROJECT OBJECTIVES

The overall project objective is to develop and undertake a collaborative stakeholder process that will inform and make recommendations for the decision on who would best administer and/or be accountable for DSM program delivery for the electricity sector in Nova Scotia. The project will also inform Government on any necessary changes in legislation / regulation needed to implement the identified options. Demand Side Management is understood here to mean a range of measures used to encourage electricity demand reduction.

The project will:

- ⇒ establish a five stage stakeholder consultation[13] process (see chart overleaf)
- ⇒ provide relevant information to stakeholders on the variety of DSM administration models currently being used (including their strengths and weaknesses, key factors that contributed to their use in a particular jurisdiction, their suitability for use in the NS situation, etc)
- ⇒ attempt to secure a consensus (not necessarily unanimity) on the recommended administrative model(s)
- ⇒ if no consensus is achievable on one model, then put forward administrative models that have significant stakeholder support identifying the strengths and weaknesses of each in the Nova Scotia context
- ⇒ identify the regulatory/legislative implications of the model(s) presented

[13] Stakeholders to be consulted in this project will be identified by 'snowball sampling' interviews with potentially interested parties early in phase 1 of the project and are likely to include a range of individuals and organisations with varying levels of direct and indirect interest in the outcome.

Dates	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5
January 10th	Task 1: Identify stakeholders [CC]; Task 2: Commence stakeholder outreach in order to: a) Agree definitional and scoping issues [DW; JL]; b) Research and agree tentative short list of generalised DSM administration options for consideration [JL; DB]; c) Achieve commitment to process [DW;CC]; d) Agree broad principles of engagement/success criteria etc [DW;CC]				
Mid-February (date to be decided)		Task 3: Meet with stakeholders as a group in order to a) Receive presentations from jurisdictions and model proponents [CC] b) Capture further inputs on criteria for successful choice of administrative model(s) [DW] Task 4: Debrief with all			

		stakeholders on an individual basis [CC]. NB DB and JL attendance optional.			
Mid-March (date to be decided)			Task 5: Meet with stakeholders as a group in order to a) Receive a presentation from Doug Baston on success factors; benefits and risk factors in response to tentative options and stakeholder views [DB]; b) Debate and re-affirm principles for shortlisting [DW]. Task 6: Debrief with all stakeholders on an individual basis [CC].		
Early April (date to be decided)				Task 7: Meet with stakeholders as a group in order to: a) Present recommendations; b) Rank recommendations; c) Attempt to drive consensus. Task 8: Debrief with all stakeholders on an individual basis. NB DB and JL to	

				be present.	
Mid-late April (date to be decided)					Task 9: Report to Government [DW; DB; JL]. Task 10: Report to stakeholders [CC].

ACTIVITIES

Project management, stakeholder outreach and senior facilitation = 30 days (5 days DW; 25 days CC)

Research components = 13 days (2 days DB; 5 days JL; 6 days CC)
- Compilation of administrative models
- Pros and cons of each option
- Implication of policy options in the NS context (best practices)
- Implementation (regulatory/legislative) issues of the chosen model (groups of preferred models)

Workshop components = 14 days (6 days CC; 4 days JL; 4 days DB)
- Workshop preparation (identify stakeholders, presenters and prepare information for attendees)
- Workshop summaries/follow-up notes
- Workshop participation – facilitation, note-taking, etc.

Report preparation = 11 days (1 day DW; 4 days DB; 3 days JL; 3 days CC)
- Report writing
- Review by Client and final revisions

The final deliverable of the project will be a report outlining the models reviewed, stakeholder responses, consensus position, considerations for implementation (regulatory/legislative issues) and suggestions for next steps.

PROJECT COSTS[14]

Consultancy time and rates

Project management and facilitation (David Wheeler) (6 days @ $4000) – *Gratis*
Project co-ordination and stakeholder outreach and research (Corrine Cash) (40 days) = $12,000 total
Senior DSM consultant (Doug Baston) @ $1000/day (up to 10 days) = $10,000 (sub-contract)
Policy consultant (Judith Lipp) @ $500/day (12 days) = $6000 (sub-contract)

Workshop/Direct Expenses

- Venue for workshops *Gratis*
- Workshop refreshments $2000
- Travel and accommodation for expert presenters $6000

Contingency $3000

Estimated Total Direct Costs (excluding Conserve NS costs): $39,000 plus applicable taxes

QUALIFICATIONS OF THE CONSULTANT[15]

This project will be executed by a team of consultants led by Dr. David Wheeler of Dalhousie University who will facilitate and oversee the consultation process. Doug Baston will provide expert insight to the project as senior DSM consultant and will attend and present at two of the stakeholder meetings. Judith Lipp is a Dalhousie PhD Candidate who has extensive experience with Nova Scotia energy policy and policies in other jurisdictions. Corrine Cash is a Research Officer in the Faculty of Management, Dalhousie University.

David Wheeler

David Wheeler is Dean of the Faculty of Management, Dalhousie University, Nova Scotia. The Faculty of Management comprises four Schools: the School of Business Administration, the School of Public Administration, the School of Information Management and the School of Resource and Environmental Studies as well as the Marine Affairs Program. The Faculty of Management at Dalhousie has a holistic and values-based approach to management education and research and is united by the philosophy of 'Management Without Borders'. The Faculty is also home to five research centres: the Eco-Efficiency Centre, the Centre for Management Informatics, the Norman Newman Centre for Entrepreneurship, the RBC Centre for Risk Management and the Centre for International Business Studies.

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[14] Because this contract contains no overhead component or margin, days incurred beyond the amounts estimated here will be charged at full rate eg where extra work is incurred at the request of Conserve Nova Scotia or where Conserve Nova Scotia accepts a prior recommendation of the consultants to conduct more work eg for the good of the process and its stakeholders. Contingency will not be incurred without prior approval of Conserve NS.
[15] Full *curricula vitae* available on request.

David Wheeler has published more than 70 articles and book chapters in a wide variety of academic journals, books, parliamentary inquiries and popular journals, and has delivered speeches to numerous conferences and events. He has written or edited three books and has done numerous television and radio broadcasts on environmental and social issues and business. David was principal author of *The Stakeholder Corporation* - the first business text to be endorsed by former UK Prime Minister, Tony Blair. He was an advisor to the UK Government on governance aspects of the Company Law Review, a member of the UK Government Advisory Committee on Consumer Products and the Environment and the Reference Group for Canada's National Report to the World Summit on Sustainable Development (Rio+10). He was co-founder of the UK business-led *Committee of Inquiry - A New Vision for Business* that reported directly to Prime Minister Tony Blair in November 1999.

Prior to his recent academic appointments, David was a member of the Executive Management team of The Body Shop International for 7 years overseeing a business operating in 50 countries with worldwide retail sales of $1 billion. As Executive Director of Environmental and Social Policy David had strategic oversight of sustainability issues and non-financial auditing and reporting. In addition to these duties he was responsible for human resources and learning for the group. In his time with The Body Shop, David oversaw the publication of five Environmental Statements in line with the European Union Eco-Management and Audit Scheme. In January 1996, The Body Shop published its first comprehensive and independently verified social, environmental and animal protection audit statement - the *Values Report.* A second *Values Report* followed in January 1998. Both reports were rated top in a worldwide ranking by SustainAbility for the United Nations on environmental and social reporting.

David started his career in the water industry where he specialised in water pollution control. Later as a Senior Research Fellow at the Robens Institute of the University of Surrey he became a leading researcher and commentator on standards of drinking water and recreational water in the UK, achieving World Health Organization Collaborating Centre status for the Robens Institute. During his time at Surrey University David was a frequent consultant to United Nations and other development agencies working in water and sanitation programs in less developed countries. He supervised development projects in twelve countries in Africa and Latin America and co-developed the *DelAgua* drinking water test kit which is now used by development agencies in more than fifty countries worldwide. The invention won a national award, presented by Prime Minister Margaret Thatcher in 1990.

In his career David Wheeler has advised a number of organizations and individuals, including:

i) The Governments of Canada, Ontario, Nova Scotia, the United Kingdom, Botswana, Brunei, Mexico, Nicaragua, Peru and Tanzania; Federal Government of Canada Departments advised include Environment Canada, Industry Canada and the Canadian International Development Agency;
ii) International development agencies including the World Health Organization, the Pan American Health Organization, the Red Cross/Red Crescent, Oxfam, the International Development Research Centre, the United Nations Development Program and the International Finance Corporation (World Bank);
iii) Companies such as BP, AMEC, Dofasco, EnCana, Novo Nordisk, TD Bank, Thames Water, The Body Shop, EML and WSAtkins;
iv) Research Organizations such as the National Round Table on the Environment and the Economy (Canada), the UK Science and Engineering Research Council, the British Geological Survey, the Water Research Centre and the Building Research Establishment;
v) Professional, civil society and other organizations and individuals including HRH The Prince of Wales, the UK Shadow Secretary for Environmental Protection, the UK Shadow Secretary for Foreign and Commonwealth Affairs, the Canadian Institute for Chartered

Accountants, Greenpeace, the National Association of Local Government Offices, the Lancashire County Council, and the Devon and Cornwall Police.

Doug Baston

Doug Baston is the Principal of Maine-based North Atlantic Energy Advisors. NAEA concentrates in energy efficiency program design, delivery, and management for utilities and public system benefits programs, as well as public policy analysis and support around issues of energy efficiency and renewable energy. In recent years he has led design of the initial Business Program for Efficiency Maine and the collaborative process that designed the New Jersey Smart Start Program for commercial, industrial and institutional customers. He is currently the lead Commercial and Industrial Advisor for the Massachusetts Collaborative. He has also served as a technical consultant to a variety of Non Governmental Organizations, including: the Natural Resources Defense Council, the Conservation Law Foundation, the Energy Foundation, the Kendall Foundation, the Natural Resources Council of Maine, Northeast Energy Efficiency Partnership, Environment Northeast, the Consortium for Energy Efficiency, the Union of Concerned Scientists, the American Council for an Energy Efficient Economy, and the World Bank.

Doug has a B.A. and a J.D. from the University of Maine and has studies utility economics and regulatory policy at Portland (Oregon) State University and Lewis and Clark College. He is licensed before the Maine and Federal bars. He serves on the Board of Directors of the New Buildings Institute and Environment Northeast.

Corrine Cash

Corrine Cash has ten years of experience working in the private sector, primarily in the medical supply industry. Through this employment she worked closely with a diverse range of professionals, ranging from administrators to engineers. A large component of her employment involved understanding the needs of clients and delivering upon these requests, all while taking into account the wide range of concerns of the various actors. She also worked with a number of volunteer organizations, both internationally and locally and has managed a variety of technical projects. With one degree focusing on Kinesiology from Acadia University, she is presently working on a second degree in International Development Studies at Dalhousie University and as Research Officer in the Faculty of Management.

Judith Lipp

Judith Lipp has more than nine years of consulting and research experience in the energy policy sector. She is currently working on her PhD at Dalhousie University where she is researching the role of public policy in promoting renewable energy. Judith grew up in Nova Scotia where she completed her undergraduate degree in economics and development studies at Saint Mary's University. In 1997 she travelled to Europe to work and study. She completed her Masters degree in Environmental Management at Oxford University in 1998 and went on to work as a research consultant with the Environmental Change Institute in Oxford, researching policies to promote energy efficiency and green electricity in the UK and European context. From 2002-2003 she worked as a consultant with IT Power, an internationally active renewable energy company. Her focus there was on the development of renewable energy promotion policies in Europe and the assessment and consideration of socio-economic impacts of renewable energy projects in developing countries. She returned to Halifax in 2003 to start her PhD. She works as a consultant on a part-time basis and in that capacity has helped prepare several energy-related studies at the national, regional and provincial level. Her work includes a project for the Nova Scotia Department of Energy, *Achieving Local Benefits: Policy Options for Community Energy in Nova* which involved two workshops and interviews with local stakeholders. She co-authored GPI Atlantic's *The Energy Accounts for the Nova Scotia Genuine Progress Index* and *A Vision and Strategy for Green Power in Atlantic Canada*, commissioned by Pollution Probe.

APPENDIX 2

Electricity Conservation in Nova Scotia

Administration of Demand Side Management Approaches

Overview of Administrative Models for Electricity DSM[16]

INTRODUCTION

Demand Side Management or DSM describes the collection of methods or actions used to influence the quantity or patterns of use of energy consumed by end users. This is done in a manner that can be quantified and verified to a degree that it may be relied upon as an energy resource—on an equal footing with a supply side option. DSM can include the promotion of energy efficiency, reduction of peak demand, fuel substitution and load management. Although DSM strategies around the world have frequently been administered by electric utilities, it is also common to see government agencies and/or independent third parties taking on this role. The task of this consultation project is to recommend an optimum administration model (or optimum models) for the Province of Nova Scotia. This 'working document' is a starting point for the process by providing an overview of possible DSM administrative models for consideration.

In reading the document stakeholders are invited to:

1) Identify any options that may have been omitted
2) Comment on the list of potential advantages and disadvantages identified for each identified option
3) Suggest amendments to the working document that may assist in reaching consensus on definitions, descriptions and potential advantages and disadvantages identified.

[16] This paper was prepared by independent consultants Judith Lipp and Douglas Baston, under contract to Dalhousie University and does not necessarily represent the views of Conserve Nova Scotia or the Government of Nova Scotia. It is the final of three drafts of a paper incorporating feedback and commentary by stakeholders.

OVERVIEW OF ADMINISTRATIVE MODELS[17]

Before wide-spread electricity market opening in the USA and Europe (late 90's onward), DSM programs were generally administered by electric utilities. With the introduction and spread of competitive markets as well as a result of various unique political experiences, that pattern has evolved. A 2003 study of DSM programs in the USA found that half of the states with public benefits energy efficiency programs were relying on state government agencies or independent organisations to administer those funds. As experience with various administrative models grows and jurisdictions acknowledge the importance of energy efficiency and demand reduction for meeting multiple public policy objectives, the question of how best to manage and administer DSM programs is highly salient.

Five main models of DSM administration can be identified. Each one is described below with examples and potential advantages and disadvantages listed in Table 1. The five models are:

Model 1 - Utility administration
Model 2 - Government administration
Model 3 - Independent third party administration
Model 4 - Dedicated energy efficiency utility
Model 5 - Hybrid administration

Assessments on these various models have not established one compelling model for all jurisdictions. Successful DSM experiences have been documented under each type of approach. According to a comparison of DSM programs in the US, "the preferred approach in any particular state seems to depend very much on the particular situation in that state. Each administrative type experienced varying levels of success when measured against program spending, program savings, emissions reductions, and overall cost-effectiveness, with no approach appearing to dominate." (GDS Associates, 2008). Below we set out the five basic models that we have identified together with a brief description of each.

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[17] The description of these models is compiled from the following sources:
Blumstein, C., Goldman, C. and Barbose, G. (2003). Who Should Administer Energy-Efficiency Programs? August 2003, University of California Energy Institute, Centre for the Study of Energy Markets. Available on-line: http://www.ucei.berkeley.edu/PDF/csemwp115.pdf, accessed 02Feb08.
Didden, M. H. and D'haeseleer, W. D. (2003). *Demand Side Management in a competitive European market: Who should be responsible for its implementation?* in Energy Policy, Vol 31, pp1307-1314.
Eto, J., Goldman C. and Nadel, S. (1998). Ratepayer-funded Energy Efficiency Programs in a Restructured Electricity Industry: Issues and Options for Regulators and Legislators. Lawrence Berkeley National Laboratory, Report Number LBNL-41479. Available on-line: http://eetd.lbl.gov/ea/ems/reports/41479.pdf, accessed 02Feb08.
GDS Associates (2008). Connecticut Electric Savings Program Study, Draft Report to the Connecticut Energy Advisory Board. Available on-line: http://www.ctenergy.org/pdf/DraftConsStudy.pdf accessed 02Feb08.
Harrington, C. and Murray C. (2003). Who Should Deliver Ratepayer Funded Energy Efficiency? A Survey and Discussion Paper. May 2003, The Regulatory Assistance Project. Available on-line: http://www.raponline.org/Pubs/RatePayerFundedEE/RatePayerFundedEEPartI.pdf, accessed 02Feb08.

Model 1 - Utility administration (with regulatory oversight)

In this model, the utility has the "central role in administering energy efficiency activities, providing general administration, program design, oversight of implementation (significant elements can be contracted out to private firms), evaluation, and cost recovery subject to regulatory oversight." (Eto et al, 1998). The utility is usually required to develop an overall DSM plan, including a proposed budget and program design explaining how ratepayer funds will be used. These plans are submitted to the utility regulator for review and approval. In some cases, utility plans reflect input from major stakeholders and possibly a consensus settlement. Utility management designs individual programs and is responsible for overall program management and administration. Program oversight varies by jurisdiction but often there is some kind of Advisory Board or 'Collaborative' that negotiates with the utility, reviews plans, and recommends to the utility regulator as shown in Figure 1. This model is found in many places including Connecticut, Massachusetts, Arizona, and Rhode Island.

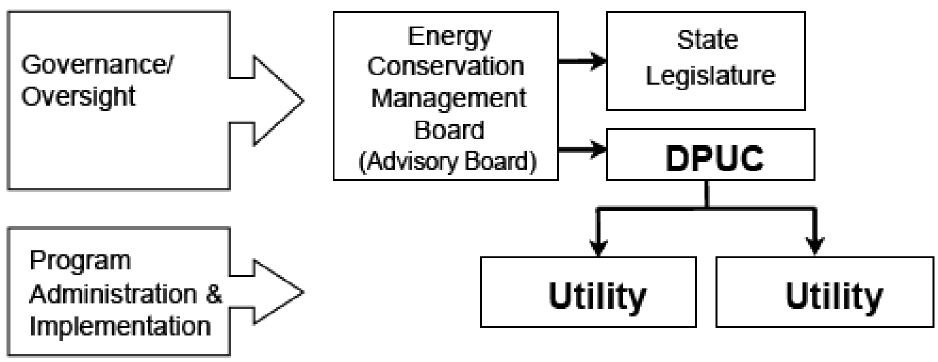

Figure 1: Utility administration (Connecticut model). From Blumstein et al, 2001
DPUC = Department of Public Utility Control

Model 2 - Government administration

Under this model, an existing public agency administers publicly funded energy-efficiency programs. This could be a public energy office, a public utilities commission, a general services administration, economic development agency, or housing and social services agency. The utility collects the public benefit funds and transfers them to the public agency, which oversees program administration, while implementation is usually contracted out to multiple delivery agents. The key is that the government agency both administers the program and designs the programs and provides most detailed delivery direction, with contractors performing under fairly close supervision of government program managers. An advisory board and/or other public agent like a regulator may be present to provide governance for accountability and oversight. An example of this model can be found in New York (depicted in Figure 2).

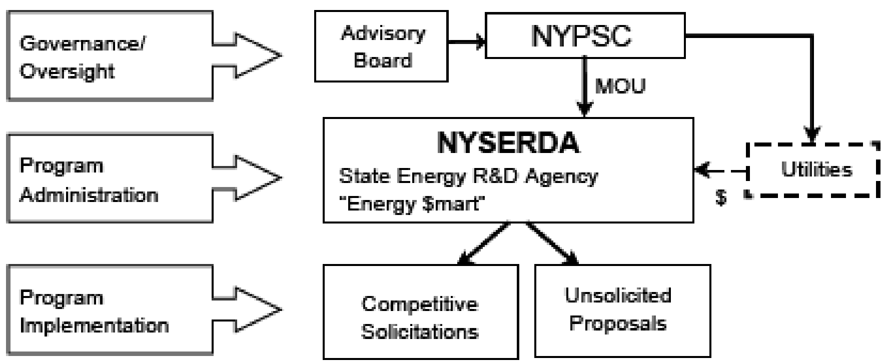

Figure 2: Government administration (New York model). From Blumstein et al, 2001

The New York State Energy Research and Development Authority (NYSERDA) is the primary administrator for energy-efficiency programs in New York. NYSERDA's administration of the programs is based on an inter-agency Memorandum of Understanding (MOU) with the New York Public Service Commission (NYPSC), which
receives guidance from an independent advisory group in its review of NYSERDA's program management and implementation (Eto et al, 1998).

Model 3 - Independent third party administration

In this option, an existing agency or other entity (chosen through tender) is designated to administrator DSM programming. This can be a not-for profit, single purpose organisation or crown corporation given the mandate to pursue public-purpose goals for energy efficiency. In some instances, this organisation may also deliver other energy programs like support for renewable energy to provide a one-stop shop of sustainable energy programming to consumers. There are several variations on how this model is set-up and governed. The arrangements surrounding Vermont's Energy Efficiency Utility are depicted in Figure 3. Oregon also uses a non-for profit agency to administer DSM. Efficiency New Brunswick is a crown corporation.

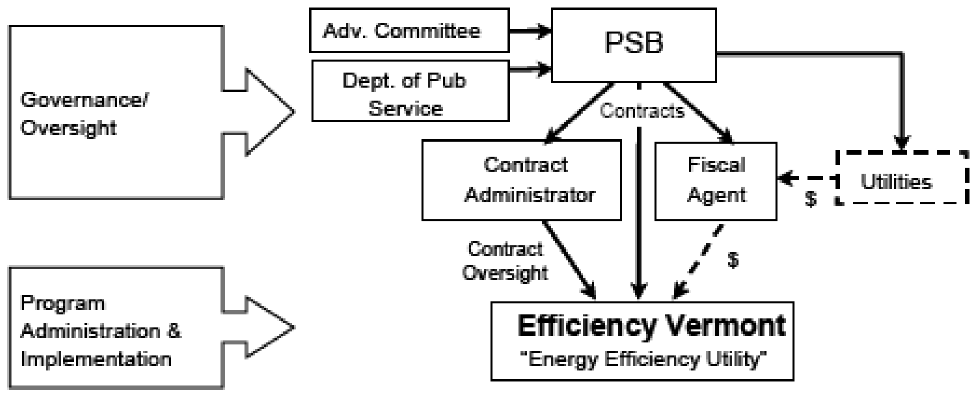

Figure 2: Independent third party administration (Vermont model). From Blumstein et al, 2001

PSB = Public Service Board

Model 4 - Hybrid administration

The hybrid approach combines elements from the previous models, which can be done in several ways. Administrative responsibility may, for instance, be shared by utilities and third parties as in California, with different programs administered by each. In 2002 the California Public Utility Commission (CPUC) "established a set of statewide programs, which were to be managed and implemented largely by the utilities, and established policy goals, budgets, and a competitive solicitation process for "local" programs, which were to be administered and implemented primarily by other entities." Before this move, the majority of funds were allocated to state-wide programs and thus under utility control. To increase the flexibility of the programs and better serve hard-to-reach customer segments, the CPUC shifted funding toward local programs operated by non-utility entities. The CPUC's own function also changed somewhat, moving beyond oversight to more directly conducting some program administration functions such as the solicitation and selection of the local program proposals (Blumstein et al, 2003). New Jersey and Maine also fit this model.

Model 5 – Energy Efficiency Utility[18]

A newly emerging concept for DSM administrative is the energy efficiency utility. The new structure is analogous to a supply utility under performance-based regulation and includes adoption of long-term budgets and resource acquisition goals. No such model has yet been implemented although Vermont has enacted legislation to enable the creation of this new structure, which will be much like other franchised utilities. This change allows the efficiency program administrator to take on larger and longer-term roles, commitments, and partnerships, including long-term resource planning, financing, and bidding resources into the regional forward capacity market. The independent third-party model in Vermont has imposed significant constraints on the evolution of these roles and responsibilities. The regulator's contractual relationship with the efficiency utility, as opposed to the judicial relationship it has with other utilities, has also presented some difficulties and constraints, hence the move towards this new structure.

[18] Based on a draft paper submitted to the American Council for an Energy Efficient Economy: Hamilton, B. (forthcoming). *Taking the Efficiency Utility Model to the Next Level.*

Table 1: Potential advantages and disadvantages of DSM administrative models

Model	Potential Advantages	Potential Disadvantages
1: Utility	• Utilities often have DSM admin experience • Single administrative and delivery entity can minimize administrative costs • Technical expertise on energy use • Established relationship with electricity users (detailed information on customer energy-use patterns & a system for billing customers) • Utility contracting and program revision processes are (relatively) more nimble than those of government • Regulatory/oversight process already established (UARB)	• Some utilities have done a poor job in DSM delivery • Without some compensating mechanism, the utility revenue model creates an incentive to increase sales, not reduce them – i.e. have interests that are fundamentally incompatible with reducing demand • Some utilities no longer have in-house expertise in this area • Difficult to integrate electric and non-electric efficiency strategies and create a single point of contact for customers • Program success determined by commitment and leadership within the utility - multiple competing priorities
2: Government	• Single agency with provincial reach can minimise administration costs • Might be less likely to be perceived by participants as having conflicts of interest • May have significant experience with dispensing funds through competitive solicitations • In theory, public agencies have well-developed processes to ensure input and accountability for use of public funds • Actual delivery can be placed in the hands of contracted market-based service providers who are in a position to pay high compensation for the best available talent • Can integrate multi-fuel strategies, gov't standards, training, renewables • Flexibility to design programs that align with broad public policy objective	• Existing agencies may be ill-equipped to focus on a new / expanded mission • Limited experience with this type of programming / limited technical expertise • Constraints imposed by staffing limitations or bureaucratic procurement requirements • Not nimble in making program adjustments • Politicized priorities and institutional caution may produce uninspired programming • Potential for budget raids that hamper achievement of goals • Difficult to provide performance incentives/penalties • Cannot be regulated, therefore less oversight and access to information compared to regulated entities / Accountability difficult to enforce • Bureaucratic requirements imposed by government can frustrate customers • Contracted program deliverers are profit-motivated private firms. Good programming may not always align with the most profitable programming. • For-profit contracts usually produce expensive program delivery • Keen program oversight is required

3: Independent third-party	• The organisational form, structure, and mission can be structured to be compatible with public-policy goals • Market participants are less likely /unlikely to perceive conflicts of interest • Can be created to have a single-focus (ability to stay on task) • Flexible planning and competitive procurement processes can be employed • The organisation may be able to attract highly motivated, skilled technical and administrative staff • More nimble in making program revisions • Expertise can be developed using local resources with some loyalty to the locale • Accountability and oversight can be focused on one entity • Administrative role can be removed in event of non-performance • Can implement strong performance accountability mechanisms • Can be overseen by the regulator • Insulated, but not totally protected from budget raids • Can integrate multi-fuel strategies, gov't standards, training, renewables	• Creation of a successful new institution/organisation depends on a broadly shared consensus regarding mission, objectives, funding sources, and appropriate organisational form and governance - these issues may be time consuming to address • A successful new institution requires the presence of some existing local energy efficiency expertise in the non-government sector • May involve high start up costs • Requires an organisation with broad reach – may be hard to establish in the short term • Relationship with the regular is contractual, not regulatory • If the third party administrator is a for-profit organization, then DSM programs would bear the added cost burden of this administrator's profit
4: Energy efficiency utility	• Analogous to existing regulated energy supply utilities thus greater familiarity for the regulator (clear relationship) • Can engage in long-term financial and resource supply commitments and partnerships (active and central role in integrated resource planning) • Potential for high mission alignment (low conflict of interest) • Ability to provide performance accountability mechanisms, including performance rewards and penalties • Insulated from budget raids • Pay structure can be aligned with other utilities thus able to attract highly motivated, skilled technical and administrative staff • Can integrate multi-fuel strategies and allow for implementation of performance accountability mechanisms for non-electric energy programs • Flexible planning and competitive	• This is an untested model - lack of experience with it creates many unknowns that need to be addressed • May require complex legal framework to be enabled – time consuming • May involve high start-up costs

	procurement	
4: Hybrid approach	• May be used when no broadly shared consensus can be achieved • Administration rests with entities that can best achieve goals – recognises strengths and weaknesses of administration by different parties • May better achieve public policy objectives (enables broader scope) – eg pursuit of both market transformation and resource acquisition goals	• Can result in confusion – responsibilities tend to overlap and need to be clearly defined • May result in higher administrative (i.e. higher overheads) and transaction costs • Needs particularly strong governance and accountability oversight • As a suboptimal model, it may exhibit many of the disadvantages of both the third party and government delivery models cited above

APPENDIX 3

Electricity Conservation in Nova Scotia

Administration of Demand Side Management Approaches[19]

OVERVIEW AND GUIDELINES FOR SPEAKERS

26th March 2008

PROJECT OVERVIEW

Commissioned by Conserve Nova Scotia (http://www.conservens.ca/), and carried out by Dalhousie University Faculty of Management (http://management.dal.ca/) this project has established an independent stakeholder consultation process to thoroughly assess the various options for administration and accountability for an electricity DSM program in Nova Scotia. The project aims to identify the range of alternative administration models and weigh the advantages and disadvantages of each with stakeholders. The aim is to build consensus based on agreement of goals and a ranking for the preferred option(s). The project will identify how the preferred option(s) could be implemented in Nova Scotia and what would be the relative benefits and risks and regulatory and legislative implications of various options. The overall objective is to make recommendations to the Government of Nova Scotia on what sort of entity would best administer DSM program delivery for the electricity sector in the Province.

Progress to Date

The project hosted its first stakeholder consultation workshop on February 22nd. Stakeholders were asked to complete a telephone questionnaire prior to the workshop to gauge their confidence in the process and their preferences regarding DSM models. Workshop participants were also sent an overview paper, outlining four types of DSM administration models. These were reviewed at the workshop and participants asked to identify key principles they wish to see in a NS model. The full list of principles was later sent to all stakeholders with a

[19] Demand Side Management is understood here to mean a range of measures used to encourage electricity demand reduction.

request to prioritise them. It is these principles the project will use to help define an appropriate DSM administration model for NS. Workshop participants were also keen to hear directly from those who have experience with different DSM models, thus we have convened a second workshop on March 26th, to which you have been invited. This document is intended to help guide you as you prepare for your presentation.

GUIDELINES FOR SPEAKERS

Your audience is knowledgeable and very interested in understanding the nuances the DSM administrative model used in your jurisdiction, including the historical context, the relationship between different actors and the advantages and disadvantages of your model from different stakeholder perspectives. Also of interest is how the model addresses various principles that have been identified at our last workshop, these are presented below. We ask that you also speak to these if you can (see Principles for Success table below). We are allowing 30 minutes for each presentation plus 20 minutes facilitated Q@A. Below we set out a checklist for your presentation in order that we achieve the highest level of comparability and relevance for our audience. The meeting will take place in an executive classroom at the Faculty of Management and there will be approximately 40 people in attendance. The meeting will be facilitated by Dean of Management, Dr David Wheeler.

Checklist for Your Presentation

- Administrative model overview, perhaps depicted in a diagram showing who interacts with who
- How and why your particular model emerged (very brief history)
- Advantages and disadvantages, risks and benefits of your particular model (as perceived by different actors)
- How well your model responds to the four Principles for Success (and any relevant objectives outlined in the table below).
- Key lessons for Nova Scotia to take away from your experience

PRINCIPLES FOR SUCCESS[20]

The following four principles and accompanying primary and secondary objectives were identified by stakeholders in Nova Scotia as key decision criteria for determining a DSM administrative model for the province. Each of the objectives is listed in order of priority based on an informal tally of stakeholders' feedback. The original questionnaire included five principles but given overlap with other areas these have been narrowed to four.

Principles for Success	Primary Objectives (in order of priority identified by NS stakeholders)	Subsidiary Objectives (also identified by NS stakeholders but with less consensus)
Accountability and oversight. There need to be 'crisp and clear' delineation of authority and responsibility between the delivery agents and the administrator.	• The DSM administrator is accountable for results/performance • Credible measurement - ability to monitor/ change/evaluate • Clear decision making structure (who makes the final decision) • No conflict of interest (convergence of interest)	Need for clearly defined roles and mission, administrator must be a trusted point of contact, chosen model must have broad stakeholder support and communicate effectively with stakeholders
Administrator effectiveness: fast and market responsive decision-making	• Flexibility to adapt to changing public policy • Flexibility for program design • Responsiveness to long range planning • Builds implementation infrastructure (relates to human resource capability)	Speed of implementation, ability to move quickly (there is an urgency for action/program implementation and delivery), nimbleness, learn from mistakes/successes of others
Compatibility with public policy goals: avoidance of unhelpful politics – eg pressure to deliver funding to constituencies, rather than to acquire cost-effective energy savings	• Maximizing contribution to achieve the economic, social and environmental goals – transparency was also named as a top priority • Must be in context of province's sustainability act • Equity component – participation for low income – Who is paying, how much? And who's benefiting? • Non–bureaucratic and entrepreneurial that encourages competitive and innovative solutions	Represent everyone
Secure funding allocation: avoidance of misuse of funds for other budgetary purposes.	• Results oriented versus spending oriented • Cost effective allocation • Predictable and dependable funding sources/multi-year	

[20] As categorised by Doug Baston and further identified by NS stakeholders.

APPENDIX 4

Stakeholder Outreach (1)

My name is Corrine Cash/Maggie Morrison and I am calling you on behalf of Dr David Wheeler who is Dean of the Faculty of Management at Dalhousie University.

Dalhousie University has been engaged by Conserve Nova Scotia on behalf of the Province of Nova Scotia to conduct a consultation process on what might be the optimum administrative arrangements for future investments in Demand Side Management. If you would find it helpful we can send you a copy of the Dalhousie University proposal for this work so you can see in more detail what is planned for the consultation process and what are the ways in which stakeholders can make their views known.

My purpose in contacting you now is to ask you about the process and what you would like to see happen. It is envisaged that there will be several opportunities for stakeholders to give private and confidential feedback through conversations like this. In addition we intend holding three workshops between mid February and mid April that Dean Wheeler will facilitate. It is hoped that you will be able to participate in these activities in order that the best advice possible can be given to Conserve Nova Scotia by the end of April. The workshops will examine a range of options and will seek to identify advantages and risks associated with these options.

If you have time I would like to ask you some questions about our proposed process and your willingness to participate. My questions should take no more than 10-15 minutes to answer. None of your responses will be quoted directly; rather your answers will be aggregated and even Dr Wheeler will only see aggregated responses. So you can be completely frank and honest in your opinions.

1) On a scale of 1-5 where 1 = no trust and 5 = total trust, can you please tell me how much trust you are willing to place in Dalhousie University to run a fair and objective consultation process?
2) On a scale of 1-5 where 1 = no trust and 5 = total trust, can you please tell me how much trust you are willing to place in the Government of Nova Scotia responding effectively to the recommendations of the consultation process?
3) On a scale of 1-5 where 1 = not at all willing and 5 = extremely willing, how willing are you to attend three half-day stakeholder workshops between mid-February and mid-April?
4) On a scale of 1-5 where 1 = not at all willing and 5 = extremely willing, how willing are you to answer up to six short individual surveys like this one between now and mid-April?
5) Would you be available on the following dates for half day facilitated stakeholder meetings looking at international best practices in DSM administration and possible local options: February 15th or February 22nd; March 14th or March 17th; April 14th or April 15th.
6) Would you be willing for me to call you again in 1-2 weeks' time to get your immediate feedback on some definitional and scoping issues?
7) Who would you recommend we also include as key stakeholders in this process?
8) Do you have any comments or advice for us going forwards?

Stakeholder Outreach (2)

My name is Maggie Morrison and I am calling you on behalf of Dr David Wheeler who is facilitating the session on Friday on administrative options for electricity demand side management in Nova Scotia.

You should have already received from Corrine Cash the paper drafted by our independent consultants on the four main options for administration of DSM based on their international review. My purpose in contacting you now is to ask you about the session on Friday and what you think it is reasonable to achieve. I also have some questions of a practical nature to ask you.

My questions should take no more than 10-15 minutes to answer. As before, none of your responses will be quoted directly; rather your answers will be aggregated and even Dr Wheeler will only see aggregated responses. So you can be completely frank and honest in your opinions.

First I would like to ask you some questions about the paper we sent to you.

1) Do you think we have captured the main options for electricity demand side management in the paper. Just to remind you, they were: Model 1 - Utility administration (with regulatory oversight); Model 2 - Government administration; Model 3 - Independent third party administration; and Model 4 - Hybrid administration. Do you agree that these are the main options?

Yes ☐ No ☐

If no, what other options might we consider?

2) Do you think we have fairly captured the potential advantages and disadvantages identified for each identified option?

Yes ☐ No ☐

If no, would you be willing to email us some suggested amendments before Friday?

3) On a scale of 1-5 where 1 = highly undesirable and 5 = highly desirable can you please comment on your CURRENT THINKING on what will work for Nova Scotia?

Highly Undesirable	1	2	3	4	5	Highly Desirable
Utility Administration (with regulatory oversight)	☐	☐	☐	☐	☐	
Government Administration	☐	☐	☐	☐	☐	
Third Party Administration	☐	☐	☐	☐	☐	

Hybrid Administration ☐ ☐ ☐ ☐ ☐

On Friday, do you think it will be possible for the group to narrow the list of 'front runner' options from four to two?

Yes ☐ No ☐

I would now like to ask you some practical questions in preparation for Friday.

Do you plan to attend?

Yes ☐ No ☐

Will anyone be attending with you (if yes, please provide names and affiliations).

Will you be staying for lunch?

Yes ☐ No ☐

We will be sending out meeting location details, but do you feel you need any more information before Friday?

Yes ☐ No ☐

If yes, record below

Is there anything else you would like to tell us in advance of the meeting?

Yes ☐ No ☐

If yes, record below:

Thank you for your time and please remember we will be starting at 9 am prompt on Friday. Refreshments will be available from 8.30.

Email back to:
Fax back to:
For telephone inquiries call:

Stakeholder Outreach (3)

My name is Maggie Morrison and I am calling you on behalf of Dr David Wheeler who facilitated the session on Friday on administrative options for electricity demand side management in Nova Scotia.

You should have already received from Corrine Cash the Key Success Factors and Principles paper. My purpose in contacting you now is to ask you about the session on Friday and whether you think we are making progress. I also have some questions of a practical nature to ask you.

My questions should take no more than 10-15 minutes to answer. As before, none of your responses will be quoted directly; rather your answers will be aggregated and even Dr Wheeler will only see aggregated responses. So you can be completely frank and honest in your opinions.

First I would like to ask you some questions about the paper we sent you on Key Success Factors and Principles.

1) Do you think we have adequately captured the Key Success Factors and Principles to guide us in making our recommendations to the Province on optimum arrangements for administration of electricity DSM in Nova Scotia?

Yes ☐ No ☐

If no, what other key success factors and principles should we consider?

2) Based on what you learned at the meeting last Friday, on a scale of 1-5 where 1 = highly undesirable and 5 = highly desirable can you please comment on what you now think will work for Nova Scotia?

Highly Undesirable	1	2	3	4	5	Highly Desirable
Utility Administration (with regulatory oversight)	☐	☐	☐	☐	☐	
Government Administration	☐	☐	☐	☐	☐	
Third Party Administration	☐	☐	☐	☐	☐	
Efficiency Utility/Vermont Model	☐	☐	☐	☐	☐	

3) Based on what happened at the meeting on February 22nd, are you now more or less optimistic that we will be able to make clear recommendations to the Province in a timely and consensus-based way?

Much Less Optimistic 1 2 3 4 5 Much More Optimistic

☐ ☐ ☐ ☐ ☐

4) Based on what happened at the meeting on February 22nd, on a scale of 1-5 where 1 = no trust and 5 = total trust, can you please tell me how much trust you place in Dalhousie University **now** to run a fair and objective consultation process?

4) Based on what happened at the meeting on February 22nd on a scale of 1-5 where 1 = no trust and 5 = total trust, can you please tell me how much trust you are willing to place **now** in the Government of Nova Scotia responding effectively to the recommendations of the consultation process?

5) I would now like to ask you some practical questions in preparation for our next meeting when we will be showcasing the 'best practice' examples of successful DSM Administration in North America. Which dates are possible for you to spend a day learning about successful DSM Administration in North America .

March xx Yes ☐ No ☐

March yy Yes ☐ No ☐

March zz Yes ☐ No ☐

6) Is there anything else you would like to tell us to help make this process efficient and successful.

Yes ☐ No ☐

If yes, record below:

Email back to:

Fax back to:

For telephone inquiries call:

Stakeholder Outreach (4)

My name is Maggie Morrison/Corrine Cash and I am calling you on behalf of Dr David Wheeler who facilitated the session on Wednesday 26th March on administrative options for electricity demand side management in Nova Scotia.

My questions should take no more than 10-15 minutes to answer. As before, none of your responses will be quoted directly; rather your answers will be aggregated and even Dr Wheeler will only see aggregated responses. So you can be completely frank and honest in your opinions.

First, we would like you to identify your stakeholder category:

Consumer Representative

Low Income Representative

Industry Representative

Municipality Representative

Environmental Representative

Renewable Energy Representative

Consultant

Other (Please Specify)

Now I would like to ask you some questions about what we learned in the meeting on Wednesday 26th March.

1) Based on what you learned at the meeting last Wednesday, on a scale of 1-5 where 1 = highly undesirable and 5 = highly desirable can you please comment on what you now think will work for Nova Scotia?

	Highly Undesirable 1	2	3	4	5 Highly Desirable
Utility Administration With Regulatory Oversight	☐	☐	☐	☐	☐
Utility Administration With Stakeholder Advisory Board	☐	☐	☐	☐	☐
Government Administration/ New Brunswick Model	☐	☐	☐	☐	☐

Third Party Administration/

Oregon Model ☐ ☐ ☐ ☐ ☐

Efficiency Utility/

Vermont New Model ☐ ☐ ☐ ☐ ☐

In order of preference, please list these five options in order of preference, starting with your most favoured option and ending with your least favoured option.

2) Based on what happened at the meeting on February 22nd, are you now more or less optimistic that we will be able to make clear recommendations to the Province in a timely and consensus-based way?

Much Less Optimistic 1 2 3 4 5 Much More Optimistic

☐ ☐ ☐ ☐ ☐

3) Based on what happened at the meeting on March 26th , on a scale of 1-5 where 1 = no trust and 5 = total trust, can you please tell me how much trust you place in Dalhousie University **now** to run a fair and objective consultation process?

4) Based on what happened at the meeting on March 26th on a scale of 1-5 where 1 = no trust and 5 = total trust, can you please tell me how much trust you are willing to place **now** in the Government of Nova Scotia responding effectively to the recommendations of the consultation process?

6) Is there anything else you would like to tell us to help make this process efficient and successful.

Yes ☐ No ☐

If yes, record below:

Email back to:

Fax back to:

For telephone inquiries call:

APPENDIX 5

Expert Presentations (3rd Stakeholder Meeting)

Energy Efficiency at National Grid: A Utility's Approach to Implementation

March 26, 2008

Tim Stout – VP Energy Efficiency / Distributed Resources

nationalgrid

National Grid and Energy Efficiency

- One of the world's largest investor owned utilities – electric and gas
- Focused on energy delivery business
- Completed merger with KeySpan in August 2007
- Approximately 4.4 million electric customers and 3.4 million gas customers
- Has delivered electric and gas efficiency programs since 1987 and 1991 respectively with no interruptions

- Efficiency programs are saving customers over $250 million annually
- Annual efficiency budget over $150 million (after merger)
- Average cost/kwh saved: 3.4 cents

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Background

Massachusetts, Rhode Island and New Hampshire (electric)

- Energy efficiency programs introduced in 1987 to address capacity constraints and environmental concerns
- Current annual budget $75 million; collected through customer surcharge
  - 1.8 to 2.5 mils per kWh
- Programs designed for all customer sectors
  - Something for everyone
- Modest shareholder incentives earned based on performance
- Participation by over 75% of all customers
- Annual participation :
  - 4,000 business customers
  - 35,000 residential customers

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Awards and Recognition

National

- American Council for an Energy-Efficient Economy (ACEEE) Exemplary Awards for 10 Efficiency Programs - 2007
- EPA/DOE Energy Star® Excellence in Energy Star Outreach – March 2007 (8th consecutive award)
- EPA/DOE ENERGY STAR® Excellence in Home Improvement Award – March 2007
- EPA/DOE ENERGY STAR® Small Business Award – 2003

Regional

- US EPA Region 1 (New England office): Environmental Merit Award – April 2007, May 2006, May 2005, April 2004, May 2002

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Projected doubling of programs over next three years in several states

- In Massachusetts, plans to double by 2011, triple by 2014

	2009		[illegible]		2011	
	Projected Budget	Projected Savings	Projected Budget	Projected Savings	Projected Budget	Projected Savings
Residential	$16.5	107,632	$23.4	152,300	$33.1	215,504
Low Income	$9.2	7,105	$13.0	10,053	$18.4	14,226
Large C&I	$22.4	76,988	$31.7	108,983	$44.9	154,148
Small C&I	$6.2	13,218	$8.8	18,704	$12.5	26,465
Total	$54.3	204,943	$76.9	289,995	$108.9	410,343

Projected budget is in millions of dollars. Projected savings are in annual MWh over a lifetime average of 13 years .

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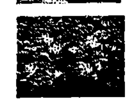
Benefits of Efficiency Programs

For Customers

- Enhanced customer service
- Reduced operating costs
- Exposure to newest efficient technologies
- Access to trusted technical expertise and financial assistance
- Assistance in meeting environmental objectives
- Average cost per kWh saved: 3.4 cents

For National Grid

- Supports commitment to the environment, climate change and local economy (including local job creation)
- Stronger long-term relationships with customers
- Improved reliability of distribution system
- Help reduce the need for new generation



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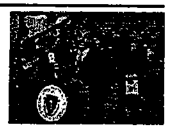
Residential Energy Efficiency Programs

- ENERGY STAR® programs
  - Lighting- CFLs and fixtures
  - Appliances- Clothes washers
  - Heating Program (gas)
  - Central Air Conditioning
  - New Construction -
- EnergyWise Program – Multifamily retrofit
- Single Family Low-Income Services
- MassSAVE – Residential retrofit
- Energy Efficiency Education



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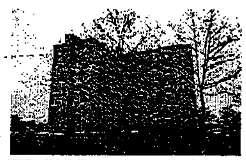
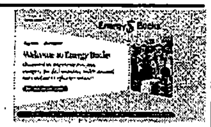
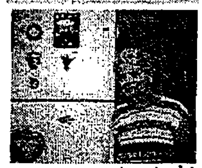
Low-Income Services

- Advertising and Marketing
- Affordable Warmth Programme
- = Weatherization
- Appliance Management
- About 15,000 low-income customers per year
- Partnerships with local agencies







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Energy Efficiency Education

- Customers can lower their energy bills through simple low cost behavior practices
- Appliance Wise Guide
  - In-home audits
  - Available on the web
- Know How Campaign, Start Small Save BIG
  - Radio ad – special website www.nationalgridus/knowhow
  - Top ten tips
  - www.myenergystar.com

As winter sets in, your best defense is to KnowHow.

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Business Energy Efficiency Programs

- Large Business Programs:
  - > ***Design 2000plus - New Construction***
    - ✓ Installation of energy efficient equipment and systems for new construction, major renovations and replacement of failed equipment
    - ✓ Incentives up to 80% of incremental costs
  - > ***Energy Initiative - Retrofit***
    - ✓ Targets energy efficient opportunities for existing buildings and equipment
    - ✓ Incentives up to 45%
- Small Business Program:
  - > Direct installation of lighting and other custom measures
  - > Audits target better performing equipment
  - ~~> Financing on bill key feature~~

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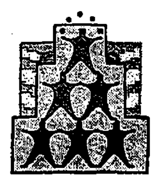
Layer "Secondary" Services on top of Core Services

- Residential central and room HVAC – new and existing
- Energy efficient schools program – new and existing
- State and municipal efficiency programs
- Other customer sectors and end-uses where a more specialized focus is needed



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Program Evaluation

- Recognition of evaluation "best practices" and leading edge evaluation approaches
- Robust program evaluation efforts prove results are real
- Efforts focus on:
  - Minimizing risk associated with our energy efficiency portfolio.
  - Determining actual savings
  - Identifying program enhancements
  - Documenting progress in achieving overall goals

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Massachusetts Shareholder Incentive

- Earned at the program portfolio level
- Includes 3 Components:
  - Savings Mechanism - Emphasizes the importance of the energy efficiency portfolio's total savings benefits
  - Value Mechanism - Emphasizes the value of the net benefits of the Company's energy efficiency portfolio
  - Performance Metrics - Performance Metrics are programmatic goals, negotiated between the Utilities, DOER and Non-Utility Parties, with the intent of impacting program design, delivery, evaluation, etc.
- Incorporates 3 Earnings Levels:
  - Design = *5% After Tax of Actual Program Expenses*
  - Threshold = *75% of Design*
  - Exemplary = *110% of Design*
- The value of each component is determined separately and then added together for the total incentive.

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Utilities as Energy Efficiency Providers

- Based on our experience in New England, utilities can be effective in delivering energy efficiency programs due to:
  - Ability to leverage existing customer relationships and encourage investment in energy efficiency
  - Well established one-on-one relationships with all large business customers
  - Understanding of customers' ongoing energy needs
  - Existence of data systems and specific market research that provide customer / facility intelligence
  - Over 34 years of combined experience delivering electric and gas efficiency programs

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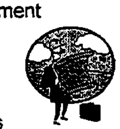
Most Pressing Need: Workforce Growth And Development – Where The Need Is

- Vast need nationally for all trades and other professions involved in program delivery and management
  - ➢ Home auditors
  - ➢ Insulation contractors
  - ➢ HVAC contractors
  - ➢ Energy engineering firms
  - ➢ Efficiency program managers and evaluators



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Essential Elements - Successful Core Programs (1)

- Well established annual goals and metrics
- Simple, efficient application process
- Rebates/incentives set at a level that strongly encourages participation – pay enough but not too much
  - ➢ Target a 1 - 2 year payback for the participating customer
  - ➢ Where appropriate, eliminate customer contributions (e.g., low income programs)
- Technical assistance – identify cost-effective efficiency opportunities – include customer copay
- Sector-specific marketing strategies

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Essential Elements Of Successful Core Programs (2)

- Well trained program management staff with access to formal and on-the-job training
- Strong relationships with trade allies
- Robust database for program management, results tracking and regulatory reporting
- Program evaluation protocols and plans
- Accountability for results
- Uninterrupted implementation to build customer and vendor trust

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Who Should Manage And Deliver Programs?

For states just beginning to deliver efficiency:

- Identify organizations, if any, in-state that have practical experience with efficiency. Assess qualifications.
- Options include state government, utilities, third-party
  - Critical elements
    - – who has the most qualified staff and management commitment?
    - - ability to provide ancillary services (e.g. legal, audit)
    - - reporting capabilities
- Build a workable process for stakeholder input
- Establish a small board with broad representation across customer sectors

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Who Should Manage And Deliver Programs?

For states with well established programs

- Maintain existing program management and delivery infrastructure
- Build resources that complement this infrastructure

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Energy Efficiency Organizations That Can Help

- Consortium for Energy Efficiency (CEE)
- American Council for an Energy Efficient Economy (ACEEE)
- Alliance to Save Energy (ASE)
- Association of Energy Service Professionals (AESP)
- International Energy Program Evaluation Conference (IEPEC)
- Regional efficiency organizations (Northeast Energy Efficiency Partnerships, Mid-West Energy Efficiency Alliance, Northwest Energy Efficiency Alliance, Southwest Energy Efficiency Alliance, Southeast Energy Efficiency Alliance)
- US EPA and DOE

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Dispelling persistent rumors

- "If energy efficiency is cost-effective, customers will pursue it without financial incentives". *Assumes unlimited capital.*
- "After 20 years of program implementation, the majority of efficiency opportunities will be exhausted". *Assumes no advances in technology.*
- "CFLs are too expensive, are slow to start, provide poor light quality and flicker". *Purchase Energy Star qualified CFLs.*
- "Many large business customers have captured all cost-effective efficiency opportunities". *No doubt true but they are few and far between.*

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Conclusions

- Adopt proven program designs rather than inventing from scratch
- Have realistic expectations. New programs need time to ramp up and may not deliver significant results for six to twelve months.
- Implement regulatory policies that incent desired efforts. Make supporting EE efforts a good business decision.
- Don't underestimate the need to focus on developing a qualified workforce to support EE efforts.

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Malden Housing Authority – Customer Profile – 52 buildings, 252 apartments

- Energy*Wise*
- Efficiency *Measures include:*
  - ENERGY STAR Fixtures
  - ENEGY STAR Bulbs
  - Staff Training

Annual Energy Savings: $9,000 or 131,000 kWh
Incentive: $164,300
Free services for Public Housing Authorities
(private landlords do contribute to program costs)

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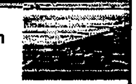
Fidelity Investments – Customer Profile



- Design 2000*plus*
- Efficiency *Measures include:*
  - Indirect Lighting
  - Low Temp Air Dist
  - High Performance Glass and Daylight Dimming

Annual Energy Savings: $27,000 or 388,000 kWh
Incentive: $217,000 with 1 year payback
Incremental Cost: $245,000

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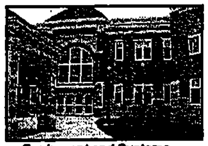
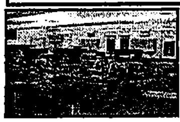
17/04/2008

Green Schools Initiative

Whitman Hanson Regional High School

Estimated Annual Electric Energy Savings	577,037 kWh
Estimated Annual Energy Avoided Cost Savings	$100,060
National Grid Incentive	$372,186





High Performance Equipment and Systems
- High Performance Envelope and Daylighting
- Optimized HVAC distribution system
- High efficiency gas boilers
- High Efficiency Lighting Systems and Controls
- Other "Green" and Renewable Systems Technologies

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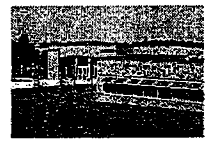
Integrated Design

National Grid's Success with Integrated Design Strategies
- 11,092,296 sq. ft. affected all building sectors
- 558,387 MWh over expected lifetime
- $25,530,433 customer value
- $8,822,802 incentives paid
- Added design cost $.25/SF
- Operating cost savings $.24/SF to $.50/SF



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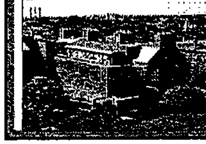
Retro-Commissioning – 2007 Enhancement

Leading Edge ...
- Examine low cost/no cost measures
- Match the capital improvement effort
- Grow capable firms to deliver services
- ESCOs and control firms play a key part in the success of the retro-commissioning efforts



Early lessons
Energy efficiency opportunities significant (low cost measures)

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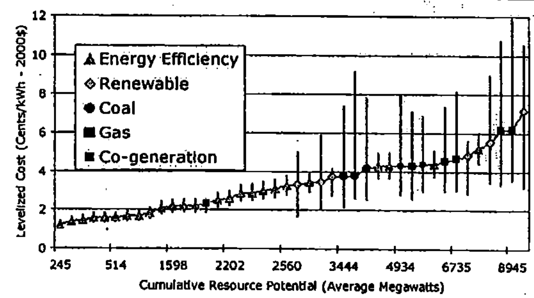
EnergyTrust of Oregon

Nova Scotia Energy Efficiency Workshop
Oregon's Delivery Model

March 26, 2008

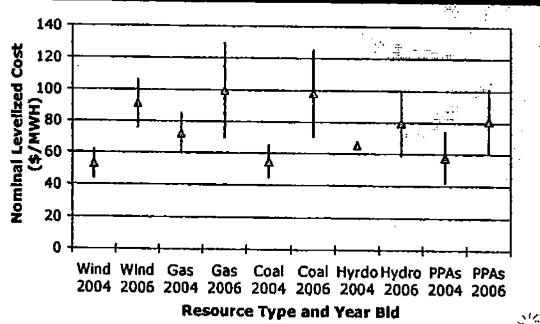
EnergyTrust of Oregon, Inc.



Resource potential for generic coal, gas & wind resources shown for typical unit size. Additional potential is available at comparable costs.

EnergyTrust of Oregon, Inc.

2



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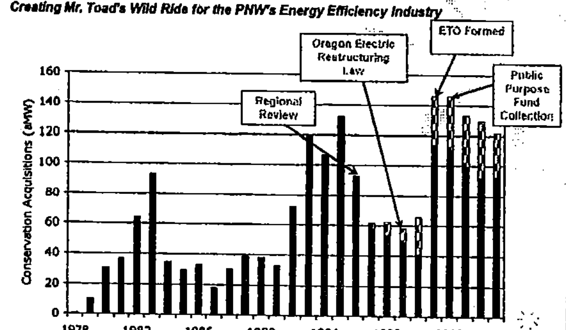
3

- Product of 1996 Regional Review and 1999 Oregon Legislation establishing a 3% public purpose charge on two electric investor owned utilities
- A 501(c)(3) nonprofit organization investing ~$48.5M/year to:
  - –Acquire cost-effective electric efficiency/conservation savings
  - –Contribute up to 100% of above market avoided costs for renewable energy projects
- Separate public purpose charge for residential and commercial customer programs for 3 gas utilities = +$10.4M
- ~1.4M Oregon electricity and gas customers with annual savings of 25-28 aMW and 1.2M therms

EnergyTrust of Oregon, Inc.

Creating Mr. Toad's Wild Ride for the PNW's Energy Efficiency Industry



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5

- 25 states plus the District of Columbia utilize this similar funding mechanism
- Total energy efficiency spending ranges from $2-240 million/year
- Martin Kushler and Dan York of the American Council for an Energy-Efficient Economy called this movement "perhaps the most significant new policy vehicle for energy efficiency in a decade."

EnergyTrust of Oregon, Inc.

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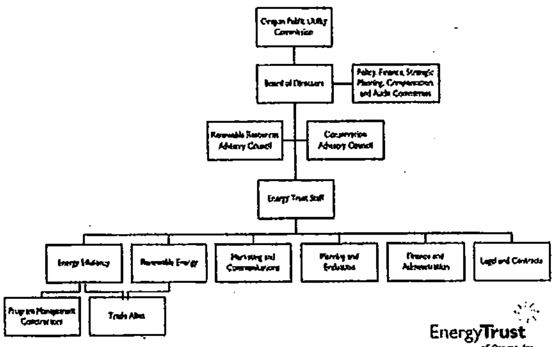

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- Contracts with Energy Trust
- Establishes minimum performance measures
- Reviews annual budget, 2-year action plan and 5-year strategic plan
- Requires quarterly and annual reports
- Requires management audit every 5 years
- Liaison to legislature
- Ex officio board role
- Participates in advisory councils and board strategic planning committee
- Can issue a "notice of concern"
- Authority to terminate contract

- Board sets direction, budget, and approves contracts
- Staff Implements
- Monitoring and Valuation (M&V) of Savings
- True up of savings
- Staff response to M&V to Board
- All M& V reports made public

- Board conflict of interest policy
- Oregon State rules for Board Members to follow
- Minimum of 9 meetings per year, down from 12
- Executive Director has $500K authority within budget and strategic plan
- Program Management Contractors and 800 trade allies
- Monthly meeting of expert Advisory Committees
  - Energy Efficiency
  - Renewables

10

- Authorized by State Legislature
- Oversight of OPUC
- Work closely with economic development agencies
- Work with utilities to relieve T&D constraints
- Whole community efficiency projects
- Rough equity rule: 80% back in any one year
- Unsolicited proposals to catch new ideas and technologies

11

- Public purpose charge extended from 2012 to 2025
- Energy Trust is extended every two years, subject to compliance with OPUC Grant Agreement
- OPUC can issue a Notice of Concern

12

- Comprehensive, integrated energy efficiency and renewable energy programs
- Objective energy information
- Technical studies and decision-making support
- Financial incentives and rebates

EnergyTrust of Oregon, Inc.

13

- Mission focused and driven
- Stable, consistent funding
- Comprehensive and integrated services
- Program management contractor delivery model
- Trade ally leverage
- Stakeholder and public involvement
- High degree of transparency and accountability
- Measurable outcomes
- Low administrative costs
- Utility collaboration

EnergyTrust of Oregon, Inc.

14

- Independent, non-stakeholder board with volunteer membership
  - Oregon Department of Energy special advisory seat
  - OPUC Ex-Officio member
- Fulfills fiduciary responsibilities
- Establishes policy
- Determines strategic direction and goals
- Reviews and approves annual budgets and plans
- Liaison to advisory councils
- Prohibited from lobbying

EnergyTrust of Oregon, Inc.

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- Conducts strategic analyses
- Plans for and designs programs
- Manages staff and contractors
- Supports trade allies
- Engages stakeholders
- Manages finances and incentive payments
- Ensures quality control and quality assurance
- Contracts for independent 3-party evaluations
- Prohibited from lobbying

EnergyTrust of Oregon, Inc.

16

To change how Oregonians produce and use energy by investing in efficient technologies and renewable resources that save dollars and protect the environment.

EnergyTrust of Oregon, Inc.

17

1. Save 300 average megawatts of electricity and 21 million therms of natural gas by 2012
2. Provide 10% of Oregon's electricity from renewable sources by 2012
3. Expand participation by those previously underserved
4. Support growth of the clean energy industry
5. Encourage Oregonians to incorporate energy efficiency and renewable energy into their daily lives

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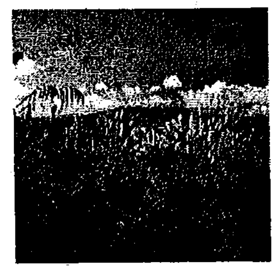
18

- Saved and generated over 1.2 billion kWh of electricity
  - Enough to power 109,000 homes
- Saved over 4 million annual therms of natural gas
  - Enough to heat 9,000 homes
- Generated 16.8 aMW by renewables; +40 average megawatts online in '07
- Served 220,000 consumers
- Retrofitted 70,000 residences and 4,000 commercial buildings
- Constructed 2,400 Energy Star homes and 440 commercial buildings
- Improved efficiency at 570 industrial sites
- Installed 1,000 solar electric and solar water heating systems
- Provided incentives for 95,000 efficient clothes washers
- Sold 530,000 packages of compact florescent lights

EnergyTrust of Oregon, Inc.

- Kept over 2 billion pounds of carbon dioxide out of the atmosphere
  - Equal to planting 3,400 acres of trees or taking 180,000 cars off the road.
- Attracted 800+ trade allies
- Paid $11.8 million in wages
- Stimulated $2.9M in new business income
- Generated 400 new jobs
- Paid over $100M in incentives



EnergyTrust of Oregon, Inc.

20

- Save 20% or more on utility bills
- Generate or use more clean power
- Minimize impacts of power price increases
- Economic Development
- Make businesses more competitive
- Improve comfort at home and at work
- Help reduce the need for new fossil fuel plants

EnergyTrust of Oregon, Inc.

21

- Requires 25 percent of Oregon's electricity to be produced by renewable energy sources by 2025
- Shifts Energy Trust renewable energy investments to projects 20 MW or less
- Allows utilities to seek Oregon Public Utility Commission approval for additional energy efficiency investment
- Extends the public purpose charge through 2025
- Will move Trust's budget to ~$80 million

EnergyTrust of Oregon, Inc.

22

EnergyTrust of Oregon, Inc.

23

EnergyTrust of Oregon, Inc.

1-866-ENTRUST

www.energytrust.org

EnergyTrust of Oregon, Inc.

24

VERMONT ENERGY INVESTMENT CORPORATION

Two Efficiency Utility Models

Efficiency Vermont

Blair Hamilton
March 26, 2008

VERMONT ENERGY INVESTMENT CORPORATION

Two Models:

Independent, Third Party Contract

- Competitively-bid contract to deliver MWh, MW and other specified results with periodic re-bid of contract.
- Performance-based compensation holdback.
- Various forms in VT, WI, NJ, IN, DE

Regulated Efficiency Utility

- Regulators appoint an entity as an "Efficiency Utility" (franchise-like).
- Performance-based regulation includes incentives for results and potential revocation of appointment.
- VT Moving to this model

Efficiency Vermont

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Vermont's Performance Contract Model

- Established in 1999 by Regulatory Order (Docket 5980) and authorizing statute (30 VSA § 209 d 2) – no sunset
- Fulfills electric utilities' obligations to implement system wide electric efficiency as part of a least-cost energy supply portfolio
- Implemented through a competitively-bid, performance-based contract for *results*
- Contract awarded to VEIC for past 7 years

Efficiency Vermont

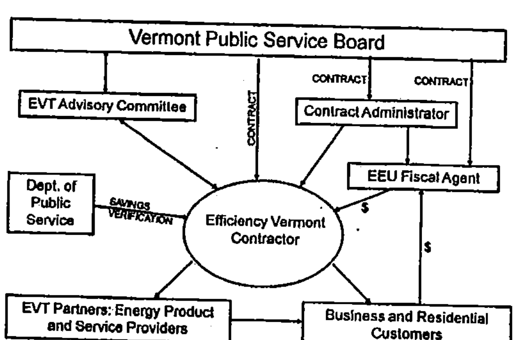
VERMONT ENERGY INVESTMENT CORPORATION

Vermont's Performance Contract Model
Scope of Responsibilities

- Acquisition of maximum cost-effective statewide electric efficiency resources
- Targeted demand reduction to avoid or defer T&D system investment
- Leverage maximum Total Resource Benefits
- Market transformation
- Provide capacity resources to regional market (ISO-New England)

Efficiency Vermont

VERMONT ENERGY INVESTMENT CORPORATION



Efficiency Vermont

VERMONT ENERGY INVESTMENT CORPORATION

What Is the Basic Mechanism?
A Contract to Supply Energy Efficiency Resources

- Model is similar to a power supply contract
- Kwh and peak KW are "purchased" from the Efficiency Vermont contractor
- Efficiency Vermont is a competitively bid, 3-year contract that includes:
  - Minimum performance requirements
  - Measurable performance indicators
  - A significant financial holdback to assure contactor performance

Efficiency Vermont — VERMONT ENERGY INVESTMENT CORPORATION

A Contract for *Results*

- Current 3-year contract is for $65 million
- Contractor commits to delivering:
  - 270,000 MWh of annual energy savings
  - 40 MW of summer and winter peak reduction
  - $184 million in net economic benefits
  - a set of quantifiable market impacts

Efficiency Vermont — VERMONT ENERGY INVESTMENT CORPORATION

2006-2008 CONTRACT PERFORMANCE INDICATORS

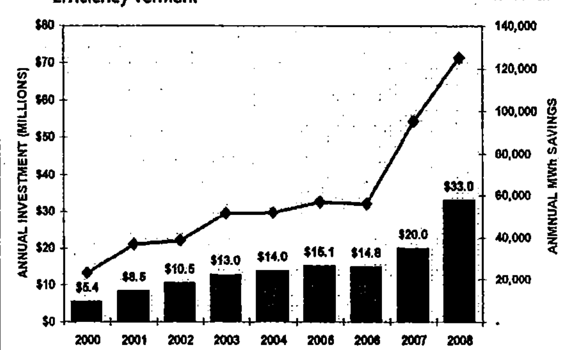
Contract Objective	Performance Goal Total
Total annual MWh savings	270,000
Total resource benefits	$184,000,000
Total summer peak MW	40
Total winter peak MW	40
Targeted Area summer peak MW	8
Targeted Area winter peak MW	8
Large grocery - CFLs	40
Hardwick & Northfield % electrical savings / % participation	3% / 39%

Efficiency Vermont — VERMONT ENERGY INVESTMENT CORPORATION

2006-2008 CONTRACT PERFORMANCE INDICATORS

Minimum Performance Requirement	Standard to Be Met
Ratio of gross electric benefits to spending	1.2
2006-2008 spending for residential customers	$19.7 million
2006-2008 spending for low-income customers	$6.3 million
Number of small business customers served	700
Minimum of Total Resource Benefits received by each county	Prescribed by county; a range of $0.5 million to $12 million

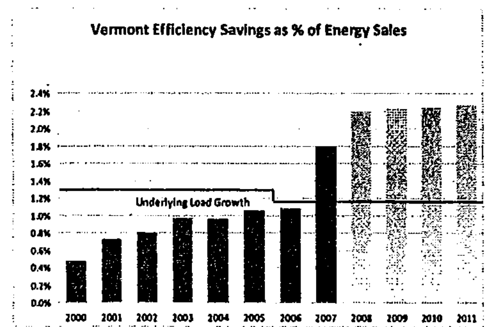
Efficiency Vermont — VERMONT ENERGY INVESTMENT CORPORATION



Efficiency Vermont — VERMONT ENERGY INVESTMENT CORPORATION

	MW Savings	GWh Savings	% of annual GWh load met by efficiency resources
2006	8.4	56	1.2%
2007	14.3	105	1.8%
2008	17.3	127	2.2%

Efficiency Vermont — VERMONT ENERGY INVESTMENT CORPORATION



NOTE: 2007 Values not yet verified; 2008-2011 values are estimates

Efficiency Vermont
VERMONT ENERGY INVESTMENT CORPORATION

Savings Verification and Audit

- Foundation is Efficiency Vermont data system and internal quality assurance systems
- Established, documented process for savings assumptions and calculations (TAG group and Technical Reference Manual)
- Annual savings verification performed by DPS
- Rigorous, independent financial audit
- PSB reports to Legislature

Efficiency Vermont
VERMONT ENERGY INVESTMENT CORPORATION

Confidence in Savings

- 3rd-party audit conducted every 3 years and reported to Legislature
- Monitoring and Verification Plan formally approved by regulators
- Savings accepted for capacity payments from ISO New England in Forward Capacity Market
- Top-down cross check on savings compared to other states and utilities

Efficiency Vermont
VERMONT ENERGY INVESTMENT CORPORATION

Capability of Efficiency Vermont Contractor

- Staff of over 100 planners, engineers, business development, marketing and administrative professionals
- 40 subcontractors
- Financial capability to manage $30 Million/yr
- Sophisticated data tracking & IT systems
- Quality Management and Reporting Systems

Efficiency Vermont
VERMONT ENERGY INVESTMENT CORPORATION

The Regulated Efficiency Utility Model

- "Making a good thing better"

Efficiency Vermont
VERMONT ENERGY INVESTMENT CORPORATION

Regulated Efficiency Utility Model

- Preserves focus on performance and results, but provides more stability and basis for longer-term planning and commitments
- Efficiency Utility appointed by regulatory "Order of Appointment" that contains terms and conditions of operation and performance-based regulation
- Keeps regulators in judicial role and public ratepayer advocate as reviewer/evaluator

Efficiency Vermont
VERMONT ENERGY INVESTMENT CORPORATION

Regulated Efficiency Utility Model

- Planning
  - A 20-year "Demand-Side Resource Plan" is set in regulatory proceedings at least every 3 yrs.
  - The Plan sets budget and savings goals for each of the next twenty years
  - The EEU role includes working with the transmission and distribution utilities on short and long-term resource planning, as well as use of efficiency to avoid or defer investments in the transmission and distribution system

Efficiency Vermont VERMONT ENERGY INVESTMENT CORPORATION

Regulated Efficiency Utility Model

- Longer-Term Appointment Benefits
  - EEU can make longer-term plans and engage in longer-term market transformation strategies
  - EEU can make longer-term power supply commitments (e.g. Forward Capacity Market)
  - EEU can enter into longer term partnerships with market participants
  - EEU can play larger role in financing/bonding

Efficiency Vermont VERMONT ENERGY INVESTMENT CORPORATION

Regulated Efficiency Utility Model

- Reporting and Transparency
  - Appointed EEU presents Annual Plan each year, with public review and comment process
  - EEU produces public Annual Reports of activities and highly detailed accounting of costs and savings
  - All records available to regulators, ratepayer advocate and Advisory Committee
  - Advisory Committee provides input and review

Efficiency Vermont VERMONT ENERGY INVESTMENT CORPORATION

Regulated Efficiency Utility Model

- Goals and Performance Indicators
  - Quantifiable Performance Indicators are specified and goals set for each in regulatory proceeding every 3 years
  - Financial holdback on compensation to EEU, contingent on performance meeting Quantifiable Performance Indicators, as in current contract model
  - EEU savings claim verification by ratepayer advocate, who makes recommendation to regulators

Efficiency Vermont VERMONT ENERGY INVESTMENT CORPORATION

Regulated Efficiency Utility Model

- Other Performance Mechanisms
  - Failure of appointee to meet minimum thresholds on quantifiable performance indicators triggers reconsideration of appointment
  - Scheduled regulatory reviews of the choice of appointee at six and twelve years
  - Any party can ask regulators to open a proceeding at any time, for cause, to reconsider choice of the appointee

VERMONT ENERGY INVESTMENT CORPORATION

Principle #1: Accountability and Oversight

Efficiency Utility Contract	Regulated Efficiency Utility
• Contractor is fully accountable for results through contract – with consequences for poor performance	• EEU is fully accountable for results to regulators– with consequences for poor performance
• Multiple, rigorous third-part audits, evaluations and savings verification	• Multiple, rigorous third-part audits, evaluations and savings verification
• Advisory committee to regulators	• Advisory committee to EEU
• Results, reports and evaluation available to public	• Results, reports and evaluation available to public and transparent in regulatory proceedings
• Efficiency utility is widely recognized, respected and seen as a trusted and objective resource to customers	• Efficiency utility continues to be widely recognized, respected and seen as a trusted and objective resource to customers

VERMONT ENERGY INVESTMENT CORPORATION

Principle #2: Administrator Effectiveness

Efficiency Utility Contract	Regulated Efficiency Utility
• Corollary to a Contract for results is very high level of flexibility granted to administrator	• Corollary to performance regulation is very high level of flexibility granted to administrator
• Contractor can move quickly without approval to respond to changing technologies, market conditions and unforeseen opportunities	• Appointed EEU can move quickly without approval to respond to changing technologies, market conditions and unforeseen opportunities
• Contractor not bound by public procurement or hiring restrictions	• Independent EEU not bound by public procurement or hiring restrictions
• Performance contract provides incentive for contractor to be efficient in operations and avoid unnecessary costs	• Performance regulation provides incentive for contractor to be efficient in operations and avoid unnecessary costs

VERMONT ENERGY INVESTMENT CORPORATION

Principle #3: Compatibility with Public Policy Goals

Efficiency Utility Contract

- Contract provides clarity in specifying the role of the contractor and the resources to be applied to support public policy objectives
- Independent, private contractor and fiscal agent provides high level of insulation from "unhelpful" political and/or legislative resource diversions
- Contractual performance indicators provide a means to address public policy objectives including equity
- Private entity and performance contract foster entrepreneurship, innovation, and avoiding bureaucracy.

Regulated Efficiency Utility

- Regulatory order provides clarity in specifying the role of the contractor and the resources to be applied to support public policy objectives (CO_2 reduction, economic development, sustainability, market transformation)
- Independent, private EEU and fiscal agent provides high level of insulation from "unhelpful" political and/or legislative resource diversions
- Quantifiable performance indicators set in regulatory orders provide a means to address public policy objectives including equity
- Private entity and performance regulation foster entrepreneurship, innovation, and avoiding bureaucracy.

VERMONT ENERGY INVESTMENT CORPORATION

Principle #4: Security of Funding

Efficiency Utility Contract

- Structure keeps funds in trust for ratepayers. They are passed through from utilities and held by an independent Fiscal Agent.
- Statute explicitly states that funds "shall not be considered funds of the state."
- RFP is for results, not for spending or price to perform services

Regulated Efficiency Utility

- Structure keeps funds in trust for ratepayers. They are passed through from utilities and held by an independent Fiscal Agent.
- Statute explicitly states that funds "shall not be considered funds of the state."
- Performance regulation focuses on results, not spending or price to perform services
- Public, regulatory process sets 20-year future budget presumptions on a rolling basis

VERMONT ENERGY INVESTMENT CORPORATION

A Few Urgent Issues

- How to create and hire staff for new entity if no solicitation?
- Accountability/jurisdiction link to UARB if no contract?
- Extent of any legislative changes required?
- Adequacy of financial commitment to support credit of new entity? Would start-up loan be required for new entity?
- How should a new entity be chartered? Sole-purpose? Should it be established with potential to expand to broader demand-side resources?
- Can NSPI continue to make on-bill financing available?
- Customer data from NSPI essential
- What potential is there for transitional structures? NSPI contract? Interim custodian?

VERMONT ENERGY INVESTMENT CORPORATION

Thank You!

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Environment Northeast

Stakeholder Boards for Energy Efficiency Programs

DSM Administration Options Forum

Dalhousie University
Halifax, Nova Scotia
March 26, 2008

Michael Stoddard, Attorney

Environment Northeast (ENE)
Who We Are

- ENGO Providing Research and Advocacy for Environmental Policies in Northeast US and Eastern Canada
  - Rockport, ME / Portland, ME / Boston, MA / Providence, RI / Hartford, CT / New Haven, CT / Charlottetown, PEI
- Program Areas
  - Energy
  - Climate Change
  - Transportation
  - Forestry, Biomass, Biofuels
- ENE staff worked on Mass. and Conn. utility collaboratives and now holds the ENGO seat on all three stakeholder boards in New England
  - Conn. Energy Conservation Mgmt Board
  - Rhode Island
  - Maine Energy Conservation Board

Halifax, Nova Scotia, March 26, 2008

Environment Northeast

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Part 1 – The Landscape

-- Growing importance of energy efficiency
-- Many significant decisions

How should we spend all that money ?!?!

- EE Programs and Procurement – Investing in a resource whose time has come
  - lowest cost resource
  - most cost effective resource now available to achieve climate change and clean air goals
  - indigenous resource
  - focus of new wave of policies
    - least cost procurement mandates & long term procurement authority
    - all cost effective mandates
    - top priority for use of cap and trade auction proceeds (or carbon offsets)
- Investments may triple (Hey, now you're talkin' *real* money)

Halifax, Nova Scotia, March 26, 2008

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EE Investment in New England

New England state SBC levels and funding amounts 2004-2005

State	CT	ME	MA	NH	RI	VT	Total
SBC Mills/kWH	3.0	1.5	2.5	1.8	2.0	2.5	
Annual Budget	$62M	$10.6M	$120M	$16.5M	$21.7M	$17.5M	$250M

If we triple funding levels by 2015	~ $750M

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Decisions, Decisions . . .

- How much to spend?
- On what resources?
- For which customer classes, locations, specific projects?
- Who should deliver it?
- How should they deliver it?
- Did they do a good job, are the investments/programs working?
- What should be changed?

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New Legislation Mandating "All Cost Effective EE" w/ Stakeholder Boards

- Connecticut: HB No. 7432, An Act Concerning Electricity and Energy Efficiency (June 2007)
- Rhode Island: S2903, The Comprehensive Energy Conservation, Efficiency, and Affordability Act of 2006
- Maine: LD 1851, An Act Establishing the Regional Greenhouse Gas Initiative (June 2007)
- Massachusetts (major energy reform expected this year)
- Predecessors:
  - California Loading Order, S.B. 1037 (2005)
  - Vermont, Title 30 VT Statute Sec. 209
- ENE sees this trend as the wave of the future
  - structures, mandates, processes, funding levels

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Environment Northeast

Part 2 – Role of Stakeholder Boards

Emerging examples from:

-- Connecticut

-- Rhode Island

Connecticut: HB No. 7432 – An Act Concerning Electricity and Energy Efficiency (June 2007)

- EE is First Choice
  - Requires state's energy needs shall first be met through all available energy efficiency and demand-side resources that are cost-effective, reliable and feasible.
- Planning - electric utility must:
  - plan for procuring energy efficiency
  - assess "how best to eliminate or stabilize growth in electric demand"
  - consider impacts on state's GHG targets
  - have plan reviewed by stakeholders and their consultants
- Institutionalized stakeholder Input
  - a broadened stakeholder board with consumer, environmental, business and gov't representatives,
  - assisted by paid expert consultants

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Conn – Resource Assessment & Procurement Plan

- Step 1 - DISCOs annually develop a Resource Assessment to examine:
  - energy and capacity needs;
  - all resources available to achieve those needs, including EE and other DSM;
  - environmental impacts of different resource choices
- Step 2 - DISCOs submit Assessment for review to the stakeholder Conn. Energy Advisory Board (CEAB)
- Step 3 - DISCOs develop a Plan, in consultation with CEAB, that includes
  - procuring all cost-effective energy efficiency,
  - addresses capacity needs, and
  - examines opportunities for renewables and CHP.
- Step 4 - The Plan is reviewed and voted on by the CEAB; can reject some or all of the plan; send it back for revisions
- Step 5 - Submit final approved Plan to regulator (DPUC) which approves (amends, rejects) procurement plan and oversees its implementation

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Conn – Conservation Plan & Program

- EE and DSM programs and projects of the Resource Plan are incorporated into the annual conservation and load management plan (C&LM)
  - Step 1 - C&LM Plan is developed together by the program administrators (DISCOs) and the stakeholder Energy Conservation Management Board (ECMB)
    - ENE appointed to the environmental seat on Board
    - cross section of stakeholders
    - specializes on EE program design and implementation
    - fully funded, rate-based independent consulting team
  - Step 2 – ECMB reviews Plan
    - may send some or all of it back for revision, more work
  - Step 3 – ECMB votes on final plan, supermajority vote required
  - Step 4 – C&LM Plan is reviewed and approved by the regulator

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Rhode Island: S2903, H8025 – *The Comprehensive Energy Conservation, Efficiency, and Affordability Act of 2006*

- Utility must submit to PUC "Least Cost Procurement" plan for all EE measures costing less than supply by Sept. 2008
  - utility also must submit "system reliability procurement" plan for DG, DR, and renewables.
- Establishes Energy Efficiency and Resources Management Council (ERMC) of stakeholders
  - comprised of consumer, environmental, business, industrial, and low income representatives; ENE appointed to the enviro seat
  - prepares "Opportunity Report" identifying all cost effective EE as well as available DG, DR, and RE
  - drafts Least Cost Procurement (LCP) standards to regulator PUC; PUC then issues LCP standards
  - works with utility to develop LCP plan for all efficiency resources cheaper than supply due to PUC

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Rhode Island: Stakeholder Board – Next Steps

- Regular, frequent meetings
- Retain consultants to:
  - Conduct "Opportunity Report"
  - Draft Least Cost Procurement standards
  - Engage in efficiency program planning and LCP plan creation with utility
- Work with utility to develop 3-year "Least Cost Procurement" and "System Reliability Procurement" Plan
- Submit Plans to regulator (PUC)
- Report back to Legislature on LCP and system reliability procurement implementation success, cost savings, and environment benefits

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Part 3 – Benefit of Stakeholder Boards

- Avoiding Temptation (and Other Mistakes)
- Supporting Other Policies and Programs

Avoiding Temptation (and Other Mistakes)

- Raid (or eliminate) the Funds
- Patronize the Patrons
  - or Succumb to Special Interests
- Forget the Public Interest
- Skim the Cream
  - Lose the Deep Reductions
- Do Nothing New; Status Quo
- Don't Ask, Don't Tell
  - or Repeat Mistakes
- Get Divided and Conquered
- Slow and Costly Proceedings

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Benefits of a Good Stakeholder Board

- Taking (Sharing) Ownership of the EE Resource and Programs
  - critical stakeholders have an institutionalized forum, process to
    - get informed
    - participate in deliberations, provide direct input
    - vote
- Unify to defend sustained, rational funding levels
  - tell success stories
  - educate stakeholders, politicians, public about benefits of EE
- Develop shared interest in good governance and good programs
  - Stand up for equitable distribution and public purposes
  - Insist on cost-effective programs & efficient implementation
- Endorse innovation and mid-course corrections, subject to review & evaluation
- Provide customer perspective on program delivery, implementation
- Ask hard questions and demand independent evaluation
  - It's your money

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Qualities of a Good Planning Process

- Iterative
- Collaborative
- Informed
- Professionally assisted
  - bring in innovation, new perspectives
- Capturing and retaining "lessons learned," institutional memory
- Cross-section of voices by
  - customer sector
  - special interests
  - geographic region

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Other Benefits of Strong Stakeholder Board
Building the Case for Related Policies and Programs

- Appliance Standards
- Building Codes
- Carbon Regulations
- Distributed Resources
  - market transformation
  - net metering
  - portfolio standards
- Reliability, capacity, diversity, energy independence

Halifax, Nova Scotia, March 26, 2008

Environment Northeast

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- www.env-ne.org

Halifax, Nova Scotia, March 28, 2008

Environment Northeast

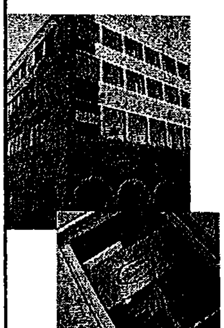
Efficiency NB:

« Building a Culture of Energy Efficiency »

Today's Presentation...

- About Efficiency NB...
- Our Programs
  - Residential Sector
  - Commercial Sector
  - Industrial Sector
  - Public Education/Consumer Products
- Principles for Success

About Efficiency NB...



- Part I Crown Corp established in 2005
- Located in Saint John
- Unique mandate in North America to provide energy efficiency programs and services for all fuels/energy sources

New Nouveau Brunswick

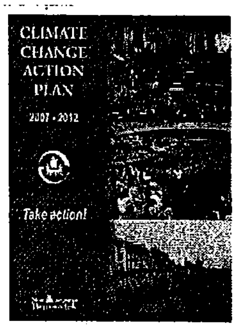
. . . About Efficiency NB

- Client-focused approach to program development in all sectors - not just looking at electricity or natural gas savings but energy efficiency needs of client using market transformation to overcome obstacles
- Efficiency NB's programs will play a key role in meeting the province's goals for the province's Climate Change Action Plan

New Nouveau Brunswick

Why energy efficiency?

To lessen the impact of energy use on the environment.



Climate Change Action Plan Highlights:

- Officially launched on June 8th, 2007.
- Link - Energy Efficiency & GHGs
- Article 3.1 Energy Efficiency Focus
- Adopt energy performance stds beyond MNECB - phase in beginning 2009
- Off Electric Strategy - Resistive Heating

New Nouveau Brunswick

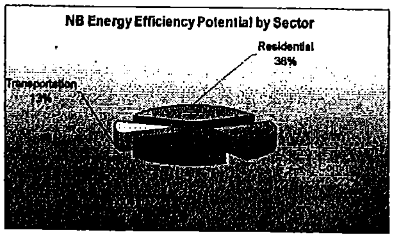
Our Mission

Efficiency NB offers sound advice and practical solutions to help New Brunswickers...

- use energy more efficiently;
- make better energy choices;
- manage energy expenses; and
- lessen the impact of energy use on the environment

New Nouveau Brunswick

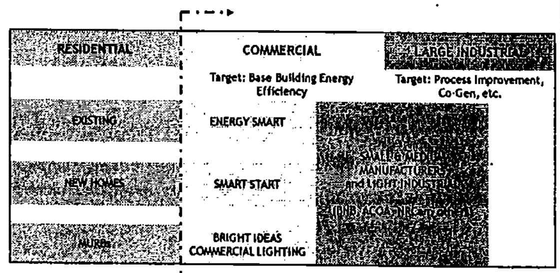
Energy Efficiency Potential



Source: Marbek Consultants Study - early '90's

New Nouveau Brunswick

Defining the Sectors



New Nouveau Brunswick

Energy Efficiency Residential Programs

- Existing Homes
- Multi-unit Residential Buildings
- New Homes

New Nouveau Brunswick

Existing Homes Program

- $400 towards the cost of a Residential Energy Assessment - most affordable home energy audits in Canada, and for homeowners who complete recommended energy efficiency upgrades either:
  - a grant - 20% of the cost, max $2,000
  - a loan - interest free, max $10,000
  - also eligible for federal eco ENERGY grant

New Nouveau Brunswick

Multi-Unit Buildings

- Small apartments up to 20 units
- Only province in Canada to offer this program
- Financial incentives are based on the number of units
  - Subsidy for audit costs - $350 - $950 and
  - Grant of 20% cost of upgrades - max $[illegible]

New Nouveau Brunswick

New Homes Program

- A grant for first owners of new homes rated at EnerGuide 80 or R-2000 certified:
  - Basic grant - $1,000
  - Central heating grant - $2,000
  - Non Electric central heating grant - $[illegible]
  - A bonus of $250 is also available for ENERGY STAR lighting and appliances

ENERGY STAR
HAUTE EFFICACITÉ
HIGH EFFICIENCY

Low Income Upgrades Program

- Administered by the Department of Social Development - provides free energy assessments and up to $4500 worth of energy efficiency upgrades to low income homeowners (1500 retrofits annually).
- $1500 per unit is also available for owners of Multi-Unit buildings (including rooming houses) with low income tenants.

New Nouveau Brunswick

Low Income New Construction

- Working with the Department of Social Development to ensure that new construction program (750 units) meets the EnerGuide 80 standard with high efficiency central heating systems

New Nouveau Brunswick

Commercial energy efficiency programs

➢ Bright Ideas Lighting

➢ Energy Smart

➢ Start Smart

New Nouveau Brunswick

AWARD WINNING!!! "Bright Ideas" Program

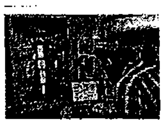
Objective...
Incentive program promoting energy-efficient lighting products.

What we offer...
➢ Efficiency NB pays the higher cost of premium energy efficient lighting products.*

The most energy efficient products on the market are now available at the same price as standard efficiency products!

New Nouveau Brunswick

Commercial Sector "Energy Smart" Program



For Existing Buildings...

New Nouveau Brunswick

"Energy Smart" Program

Objective...
Commercial buildings retrofit incentive program

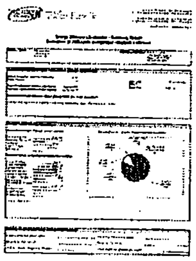
What we offer...
➢ Grant of up to $2,000 for an energy audit.

➢ Grant of up to $50,000 toward the energy retrofitting project cost.

Currently
buildings in the program

New Nouveau Brunswick

"Energy Smart" Audit Summary Report



Contains...

- Energy Profile
- Business Case
- Incentives
- GHG Reductions

New Nouveau Brunswick

"Start Smart" Program

Objective...
Incentive program for the construction of energy efficient commercial buildings.

What we offer...

- Grant of up to $60,000 to offset the costs associated with designing sustainable high-efficiency buildings.

New Nouveau Brunswick

"Start Smart" Prescriptive Package...

Efficiency NB is developing a cost-effective and user-friendly approach to help developers/contractors build energy efficient buildings.

- Targeted at new construction < 75,000 sq feet.
- Objective is for all new construction to reach energy efficiency levels 30 % better than the National Model Energy Code.
- Efficiency NB is working with the New Buildings Institute (US) and Maricor to adapt to Canadian context.

New Nouveau Brunswick

Other Incentive Programs in the Commercial Sector

At the Federal level...

- ecoENERGY Retrofit Incentive for Buildings*

*Office of Energy Efficiency, Natural Resources Canada

ecoENERGY an ecoACTION initiative

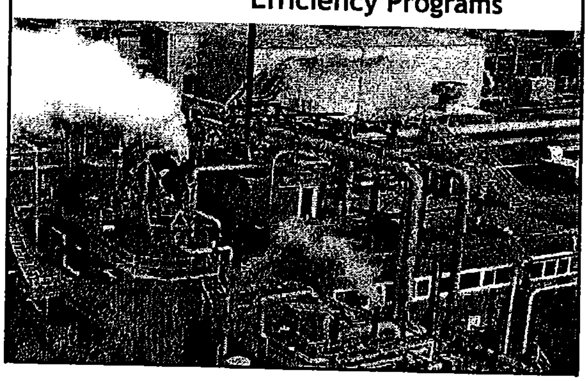
At the Provincial level...

- Business New Brunswick offers financial incentives to support energy efficient process improvements or equipment upgrades for NB manufacturers on a case-by-case basis.

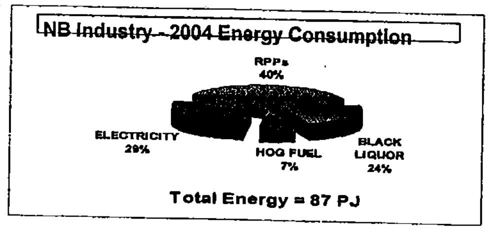
*For more information, visit Business NB's website or contact one of their Sector officers.

New Nouveau Brunswick CANADA Business New Brunswick

Industrial Sector Efficiency Programs



Industrial Energy Profile



PJ = Peta Joule(10^15)

Reference: 2004 Marbek Resource Consultants Study

New Nouveau Brunswick

Industrial Energy Efficiency Programs

Goal...

Assist New Brunswick's largest energy users to reduce their energy consumption/GHGs and improve their competitiveness.

Industrial companies can contact the Agency right away for any additional information or advice.

New Nouveau Brunswick

Program Objectives

- Establish a strategy for sustainable energy and GHG reductions.
- Address key barriers (resource, financial, risk)
- Promote technology and management best practices.
- Support productivity improvements and increased competitiveness.
- Build capacity and culture of efficiency.

New Nouveau Brunswick

Energy Efficiency in the community . . .

Public Education and Consumer Products

New Nouveau Brunswick

Public Education

- Energy Efficient Communities
- Public Awareness Campaigns

Consumer Products

- Lighting
- Appliances
- Home Electronics

Community Partnerships

Supporting communities to reach measurable goals for reducing energy consumption.

Active Community Partners

Perth-Andover / Bathurst
Bouctouche - Sackville area
Fredericton / Tracadie
Pokemouche / Neguac / [illegible]
Caraquet

New Nouveau Brunswick

Consumer Products

- Efficiency NB will be working to increase consumer take-up of high efficiency residential lighting and ENERGY STAR clothes washers.

- Also, public education initiatives to broaden the awareness of how to manage stand-by power.

New Nouveau Brunswick

. . . A National Leader in Energy Efficiency

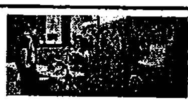
- Efficiency NB has the most comprehensive suite of residential energy efficiency programs of any jurisdiction in Canada.
- Since April 2007, New Brunswick has had more homeowners complete their initial home energy evaluations than all three other Atlantic provinces combined.
- And representing only 2.3% of the Canadian population, NB homeowners accounted for 8.5% of initial audits conducted nationally - more than triple the audit rate per capita.

New Nouveau Brunswick

. . . A National Leader in Energy Efficiency

- In less than one year, Efficiency NB's New Homes Program has transformed the new housing market in the province - raising the level of high efficiency new homes from 2.5% to 16% in one year.
- Efficiency NB's commercial building retrofit program - Energy Smart - launched in April, currently has more buildings participating in the program than the entire national program. (165)

New Nouveau Brunswick



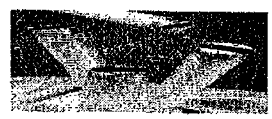
. . . A National Leader in Energy Efficiency

- New Brunswick is the first province in Canada to roll-out a comprehensive industrial energy efficiency program incorporating all fuels used by large industry - not just electricity.
- NB offers the most comprehensive community energy efficiency campaigns in Canada.

New Nouveau Brunswick

. . . A National Leader in Energy Efficiency

- Within 5 months of launching its commercial lighting program, "Bright Ideas", Efficiency NB won an international award from the American Council for an Energy Efficiency Economy - the only Canadian energy efficiency program provider to receive the ACEEE's highest level of award.



PRINCIPLES FOR SUCCESS

New Nouveau Brunswick

1. Accountability and Governance

- Responsible to the Legislative Assembly and as a Crown Corporation to produce an Annual Report and appear before the Crown Corporations Committee
- Independent Board of Directors (5) responsible for providing advice on the strategic direction of the Agency - energy efficiency "champions"

New Nouveau Brunswick

. . . Accountability and Governance

- Evaluation, Measurement and Verification one of the core functions of the Agency, built into all programs
- Technical Working Group established with reps from NB Power, Dept's of Energy and Environment to develop consensus on protocols for measurement of energy savings in the province

New Nouveau Brunswick

2. Administrative Effectiveness

- Able to move quickly to adapt to changes in public policy (EnerGuide)
- Control program design, Agency has capacity to do long-range planning and develop long-term programs
- Can contact with private sector companies, federal government

New Nouveau Brunswick

. . . Administrative effectivess

- Opportunities for inter-provincial cooperation on programming - MOU with Conserve Nova Scotia re: "Bright Ideas" program
- Have significantly increased human resource infrastructure building capacity in the private sector

New Nouveau Brunswick

3. Compatibility with Public Policy Goals

- Access to energy efficiency programs for low income homeowners-- (1500 retrofits annually saving homeowners, on average, $900 a year)
- Greenhouse gas emission targets through Climate Change Action Plan

New Nouveau Brunswick

4. Secure funding allocation

- All programs (except low income) meet "cost-effective" test.
- As a Crown Corporation, Agency can roll funds over from one year to the next.
- Loans program is established as a revolving fund by the Province

New Nouveau Brunswick

Appendix B

Media Articles Regarding A New DSM Administrator

New energy agency; Independent body to run province's conservation programs starting in 2009
Halifax Chronicle Herald (Business, page C1)
By JUDY MYRDEN
Fri. Dec. 12

A NEW business-style entity will be created next year to replace Nova Scotia Power as the administrator of energy-efficiency programs in Nova Scotia, the government announced Thursday in Halifax.

"What this means for Nova Scotians is more opportunities for electricity efficiency and conservation, new sources of information and programs to use less electricity, energy savings and lower costs, and cleaner air by using less fossil fuels," Energy Minister Richard Hurlburt said.

A board of directors and Nova Scotia's Utility and Review Board will oversee the new administrator, which will have an approved budget of $9.7 million in 2009.

David Wheeler, dean of Dalhousie University's faculty of management, gave the government a report almost six months ago recommending that it put in place a new, independent administrator to help Nova Scotians cut electricity consumption.

Mr. Wheeler said the recommendation was based on meetings with 40 business, environmental and other interest groups on the best way to implement programs to help consumers reduce their use of electricity.

All agreed the task should be taken out of the hands of NSP and the government, he said.

Nova Scotia has an opportunity to become an "international leader" in energy conservation programs with the establishment of an independent administrator, Mr. Wheeler said.

"If this develops as it has in other jurisdictions, we'll see a lot of small engineering firms grow on the back of the need for energy-efficiency measures."

Cheryl Ratchford of the Ecology Action Centre said Nova Scotia will be the first province in Canada to have an arm's-length administrator of energy conservation programs.

"This positions Nova Scotia as a leader in energy efficiency and it is the most effective way to go in terms of accountability and results," said Ms. Ratchford, whose group had been pushing for programs to reduce energy usage.

The new administrator is expected to be in place by June. Legislative changes are required before the task can be taken away from NSP.

"They did not want it in government, they did not want NSP running demand side management or (energy conservation)," Mr. Hurlburt told reporters. "They wanted an independent administration of it and I fully endorse that."

The provincial government has also adopted the controversial recommendation that the conservation programs be funded by power users in the province.

In the past, this proposal has angered NSP's largest electricity customers, pulp and paper companies New Page Port Hawkesbury and AbitibiBowater, who want taxpayers to fund the program.

Halifax lawyer George Cooper, representing New Page Port Hawkesbury, attended the announcement on Thursday but declined to comment.

"I have not been given any instructions," Mr. Cooper told reporters.

Mr. Wheeler admitted there were "one or two industrial interests" that felt this wasn't the way to go.

"There's always some concerns around change but if we all understand, this is a way to save money," he said.

In 2005, the Utility and Review Board rejected NSP's request to spend $5 million on energy conservation. Part of the plan was to spend $100,000 to encourage people to switch to energy-efficient light bulbs.

Instead, the board ordered an independent review of the program.

Energy efficiency administrator picked
Allnovascotia.com
By Gillian Cormier
Fri. Dec. 12

The task of managing ratepayer money dedicated to cutting energy consumption has been given to an independent not-for-profit administrator.

Nova Scotia Power Inc. (NSPI) will hand over control of its demand side management (DSM) program next year to a new agency, tentatively named NS Electricity Efficiency Agency.

David Wheeler, dean of Dalhousie University's faculty of management, prepared a study on the best administrative model for DSM delivery in Nova Scotia.

An independent administrator was recommended in a stakeholder agreement in March, so the move comes as little surprise.

DSM refers to programs designed to reduce the amount of electrical usage on the consumer end - as opposed to supply side management, which involves generating more power by adding capacity to the grid through new power plants.

The report recommends creating an independent entity, overseen by the Nova Scotia Utility and Review Board, reporting to a board of directors.

Wheeler said the independent model was supported by a majority of stakeholders - though he wouldn't say who wasn't on board. Other options included a privately;y managed model, continued NSPI administration or handing control over entirely to government.

The Ecology Action Centre had called for an independent administrator, saying NSPI administration left the DSM fund vulnerable to budget raids. Most other stakeholders agreed that control of the program should be outside NSPI.

The DSM programs were approved by the Utility and Review Board and the costs will be recovered in rates starting in 2009. NSPI spent $3.2 million in 2008 on DSM programs and will spend $9.7 million in 2009. The DSM program makes up about 0.2% of the 9.3% rate hike that comes into effect next month.

The agency will be required to meet performance targets and will receive incentives to do so. The board of directors will be chosen based on merit by the Utility and Review Board.

Wheeler also recommended that the agency's funding be secure and the door remain open for its mandate to be expanded in the future.

Alan Richardson, spokesperson for NSPI, says the utility wants to flatten its 1$-2% growth in energy consumption through DSM programs.

The DSM program is in response to long-term projections that suggest the province's power needs are growing at such a rate that of demand is not curbed, a $1 billion, 400-megawatt coal fired power plant may need to be built to keep up.

But Richardson says more will need to be done to eliminate the need for construction of another plant, he says.

The program was largely considered a good idea by the board and intervenors. A settlement agreement was signed with most stakeholders in March - including large customers Newpage and Bowater Mersey.

Richard Hurlburt, minister responsible for Conserve Nova Scotia, accepted Wheeler's recommendations.

NSPI will continue as interim administrator until the new administrator is up and running, which is expected to be by the end of 2009. Changes to legislation that will allow for the creation of this agency are scheduled for spring.

Province to launch electricity conservation agency
METRO Halifax, page 1
BY JENNIFER TAPLIN
Fri. Dec. 12

A new electricity conservation agency is on the way.

After a 56-page report by a Dalhousie consultation team, the province has decided to launch a new electricity agency.
Its purpose is to dole out money and oversee programs geared towards reducing electricity in the province.

"You need to think of it as a highly-focused not-for-profit business," said David Wheeler, Dalhousie's dean of management, at a media briefing yesterday.
"It will not become some sprawling bureaucracy, it will be run in very business-like terms to deliver results."

For example, a company or individual who wants to retrofit office buildings to make them more energy efficient would be able to apply to this agency.

The agency would provide funding, but also make sure the project is producing results.

"The possibilities are limitless," Wheeler said. "The trick is to have the money follow the best value for money options... This will allow people to move on the things that really matter."

The independent, non-profit agency will be funded by Nova Scotia Power Inc. Alan Richardson with NSP said they're looking to find more support for customers who want to conserve.

"The faster we can ramp it up the better," he said.

Sound good?

Well, it won't be happening anytime soon.

Richard Hurlburt, minister responsible for Conserve Nova Scotia, said legislation will be drafted in the spring sitting of the legislature.

"We expect the new administrator to be up and running before the end of next year," he said.

Not fast enough, according to NDP MLA and environment critic Graham Steele.

"This is a good report but the problem we've always had is this should have happened a long time ago. The government has been painfully slow moving on energy efficiency initiatives," he said.

"If what they need is legislation, call back the legislature in January. We're ready to go on this."

Appendix C

2010 DSM Plan

Table of Contents

1.0 OVERVIEW OF 2010 DSM PLAN

Table 1-1 presents program budgets, the number of program participants or units, the incremental annual GWh energy and MW demand savings at the generator, and the total resource cost test (TRC) ratio for the 2010 DSM programs. Supporting data is included in Attachment 1.

Table 1-1 2010 DSM Budget, Participants, and Savings

2010 DSM Plan	Budget* ($ millions)	Number of Participants / Units	Incremental Annual Net Energy Savings at Generator (GWh)	Incremental Annual Net Demand Savings at Generator (MW)	Total Resource Benefit/Cost Ratio (TRC)
Residential					
Efficient Products *	2.07	40,661	8.86	1.86	1.9
Existing Homes *	2.12	2,700	4.93	1.41	1.6
Low Income Households *	2.18	1,500	5.26	1.17	2.0
New Homes *	2.07	1,000	4.37	1.40	1.4
Residential Subtotal	**8.44**	**45,861**	**23.43**	**5.84**	**1.7**
C&I					
Rx Rebate	0.15	-	-	-	-
Custom *	6.26	120	38.19	6.40	3.1
Small Business DI Lighting *	5.62	600	13.98	3.30	1.8
New Construction *	1.76	35	7.06	1.38	2.7
C&I Subtotal	**13.80**	**755**	**59.23**	**11.08**	**2.6**
Multi Sector					
Education and Outreach	0.40	-	-	-	-
Development and Research *	0.25	-	-	-	-
Multi Sector Subtotal	**0.65**	**-**	**-**	**-**	**-**
TOTAL	**22.89**	**46,616**	**82.67**	**16.92**	**2.3**

Notes:
This figure is expressed in 2010 dollars.
* Programs established in 2008/2009.

2.0 2010 DSM PROGRAMS

The following sections present the programs that comprise the DSM plan for 2010. These are general program descriptions with key highlights. Detailed implementation plans will be developed prior to program implementation.

The proposed programs for 2010 are:

1. Efficient Products –2008 Launch
2. EnerGuide for Existing Houses – 2009 Launch
3. Low Income Households –2008 Launch
4. EnerGuide for New Houses – 2009 Launch
5. Commercial and Industrial Prescriptive Rebate – 2010 Development
6. Commercial and Industrial Custom –2008 Launch
7. Small Business Direct Installation –2008 Launch
8. Commercial and Industrial New Construction – 2009 Development, 2010 Launch
9. Education and Outreach – 2010 launch
10. Development and Research – 2009 (Data Tracking System), 2010 Launch

2.1 Efficient Products

2.1.1 Description

The Efficient Products Program will secure electric energy and demand savings by increasing the sale and installation of energy efficient lighting, appliances, consumer electronics and other mass market products.

The program will build on the widely recognized ENERGY STAR® brand, promoting a wide range of ENERGY STAR® labeled products to consumers and offering financial incentives for selected products that meet or exceed the ENERGY STAR® level of performance. Program strategies are expected to include marketing only promotions, consumer rebates, upstream incentives, community based strategies, turn in strategies, social marketing and direct installation of measures. The program will address the following barriers:

- Customer awareness
- Pricing
- Concerns about product quality
- Availability of range and variety of efficient products

In 2010 the program is expected to expand from its 2008-2009 focus on lighting products to (1) selected home appliances (e.g. washing machines, refrigerators, freezers and/or dehumidifiers), (2) consumer electronics, and (3) savings that may be available through turn in of inefficient or spare appliances.

Four key areas of focus for this program are anticipated:

- Consumer marketing and education that will generally increase customer awareness and demand for energy efficient products and for ENERGY STAR® labeled products in particular.
- Building partnerships with retailers who sell efficient products, with the objective of having them increase stocking, promotion and market share for sales of ENERGY STAR® labeled products. This may require a range of support activities including provision of point-of-sale marketing collateral, cooperative advertising, in-store events, sales training and financial incentive strategies that provide benefits to products retailers.
- Working through upstream market channels to influence the supply and pricing of selected energy efficient products. Examples include CFL buy-downs, the commercial lighting strategy currently implemented by Conserve Nova Scotia, and participation in manufacturer focused initiatives for consumer electronics.

- Direct installation strategies, building on the program component begun in 2008 in which compact fluorescent lamps and exit signs were directly installed in small business premises.

Program design may be modified as appropriate based on program experience in 2009.

2.1.2 Eligible Participants

Customers in all sectors, who use or purchase the types of products covered by the program, will be able to participate.

2.1.3 Delivery and Implementation

The DSM Administrator will determine the program management and implementation functions it chooses to conduct with in-house staff and which will be performed by implementation contractors. Any sales and/or installation of energy savings products or measures will be conducted by businesses other than the DSM Administrator. The Administrator may choose to competitively procure management and/or implementation services, using performance based contracts where an element of contractor compensation is based on achievement of energy savings and other performance goals.

2.2 EnerGuide for Existing Houses

2.2.1 Description

The 2010 program will build upon and be delivered in partnership with Conserve Nova Scotia’s EnerGuide for Houses Program. The electrical efficiency component of the program will seek to (1) maximize cost effective electrical savings in all homes that are part of the program, and (2) increase program participation by homes with electric space heating. Initial experience gained in 2009 will be used to refine the program design and implementation.

The program seeks to promote comprehensive, cost effective energy efficiency improvements to existing homes through:

- Marketing and promotion of the benefits of home energy efficiency improvements
- Provision of home energy assessments by qualified individuals
- Financial assistance for recommended, cost effective measures

Through this program, each of these three components of the Conserve Nova Scotia program will be enhanced by:

- Supplemental marketing and promotion of the EnerGuide for Houses program, to increase consumer awareness and demand in general and through activities focused on increasing participation of homes with electric space heating
- Additional financial incentives to increase the adoption of cost effective electrical measures in all homes, and of space-heat savings measures in homes with electric space heat

Anticipated measures, where cost effective, may receive program financial incentives above those provided in Conserve Nova Scotia’s base program. The measures may include:

- Lighting and lighting fixture retrofits and/or replacements
- Efficiency measures that reduce electric water heating energy use
- Selective electric appliance replacement
- Efficient motors in replacement furnaces
- Selected emerging measures to control appliances or electronics
- Other custom, site specific electric efficiency measures that may be determined to be cost effective

In homes with electric space heat, financial incentives may be provided for a full range of envelope and heating system measures that are determined to be cost effective on a site specific basis. These may include:

- Comprehensive air sealing to reduce building envelope leakage
- Adding insulation of attics, walls and basements
- Heating system controls
- Other custom, site specific electric heat saving measures that may be determined to be cost effective

Eligible measures and any rebates will need to be coordinated and aligned with the Conserve Nova Scotia's promotion of products for the base EnerGuide for Houses Program, including:

- Insulation
- Draft proofing measures
- EPA certified wood stoves
- Pellet stoves
- Electronic thermostats for electric heat
- Solar domestic hot water systems
- Drain water heat recovery systems
- ENERGY STAR® windows and doors

Program design may be modified as appropriate based on program experience in 2009.

2.2.2 Eligible Participants

Program eligibility will be in accordance with the Conserve Nova Scotia EnerGuide for Houses Program.

2.2.3 Delivery and Implementation

This program will partner with Conserve Nova Scotia's EnerGuide for Houses Program. It will seek to harmonize program design and implementation into a uniform and efficient, province wide program, where funding from all sources is integrated and benefits are maximized. The DSM Administrator will, in collaboration with Conserve Nova Scotia, and determine the program management and implementation functions it will conduct with in-house staff, Conserve Nova Scotia and its contractors, and contractors to the DSM Administrator. Any sales and/or installation of energy savings products or measures will be conducted by businesses other than the DSM Administrator. This program is contemplated to enhance Conserve Nova Scotia's program and make maximum use of the EnerGuide for Houses structure and delivery agent approach.

2.3 Low Income Households

2.3.1 Description

The 2010 program will build upon and be delivered in partnership with Conserve Nova Scotia's Residential Energy Affordability Program (REAP). The overall program facilitates the implementation of cost effective electrical and fossil fuel energy saving measures for low income households. The electrical efficiency component of the program will seek to (1) maximize cost effective electrical savings in all homes that are part of the program, and (2) increase program participation by homes with electric space heating. All DSM measures and services provided through this program will be provided to eligible low income customers at no cost.

Initial experience gained in 2008-2009 will be used to refine the program design and implementation for 2010. The 2008 program relied exclusively on existing REAP intake procedures, whereby single family, low income homeowners who are eligible and have applied for housing repair and rehabilitation assistance are also considered for potential energy efficiency improvements. In 2009, efforts are being undertaken by NSPI, Conserve Nova Scotia and the Program Development Working Group to expand and enhance this base program design and implementation. These efforts are focused on:

- Developing and implementing a direct application process for the program
- Developing procedures and capabilities to target participants with high energy savings potential and high household energy cost burden
- Developing and implementing proactive outreach to identify and serve target low income households, particularly those with high electrical usage for space heating

Electric-savings measures that may be provided to all income-eligible homes may include:

- Lighting and lighting fixture retrofits and/or replacements
- More efficient electric water heating energy use
- Selective electric appliance replacement
- Efficient motors in replacement furnaces
- Control of appliances or electronics
- Custom and site specific electric efficiency measures

In homes with electric space heat, a full range of envelope and heating system measures may be provided. These may include, but would not be limited to:

- Comprehensive air sealing to reduce building envelope leakage
- Insulation of attics, walls and basements
- Heating system controls
- Other custom, site specific electric heat-saving measures that may be determined to be cost effective

Program design may be modified as appropriate based on program experience in 2009.

2.3.2 Eligible Participants

The long term objective of the program is to overcome the market barriers to making cost effective energy upgrades for low income customers. For this program, the March 2008 DSM Settlement Agreement suggested income eligibility as the Low Income Cut-Off (LICO) level for preliminary program implementation. Wider definitions of low income eligibility were suggested for future consideration. Initial implementation of the program in 2008-2009 has used REAP eligibility, which, in turn, is the eligibility level and process used for the Residential Rehabilitation Assistance Program (RRAP) housing rehabilitation program by the Department of Community Services. The definition and process for establishing income eligibility for this program is expected to continue to evolve over the 2009-2010 period, recognizing both long term program objectives, the value of consistency in eligibility criteria among Low Income programs delivered by different entities, and practical program delivery considerations.

While the DSM Plan has the objective of securing cost effective savings and addressing the market barriers to cost effective energy upgrades for all low income housing, the initial implementation of this program has been limited to owner-occupied, single family dwellings that were eligible for, and could easily be served through, the RRAP service delivery model. In 2009, the DSM Administrator and the PDWG are expected to address the issue of expansion of this program, or establishment of a complementary program, to address multiple unit and rental low income housing.

2.3.3 Delivery and Implementation

This program will partner with Conserve Nova Scotia's REAP Program. It will seek to harmonize program design and implementation into a uniform and efficient, province wide program, where funding is integrated and benefits are maximized. The DSM Administrator will, in collaboration with Conserve Nova Scotia, determine the program management and implementation functions it will conduct with in-house staff, Conserve

Nova Scotia and its contractors, and contractors to the DSM Administrator. Any sales and/or installation of energy savings products or measures will be conducted by businesses other than the DSM Administrator.

2.4 EnerGuide for New Houses

2.4.1 Description

Each year, approximately 3,000 new homes are built in Nova Scotia, creating new demand for electricity. Given recent high levels of builder and consumer choice to use electric space heating in residential new construction, these new homes represent an important, time sensitive opportunity to secure energy efficiency savings that will persist for many years.

The existing framework and infrastructure to deliver Conserve Nova Scotia's EnerGuide for New Houses program provides a valuable foundation that can be built upon to achieve DSM objectives in this market. It is anticipated that this program will be delivered in full partnership with Conserve Nova Scotia in a mutual effort to maximize energy savings in all residential new construction through a unified, efficient provincial effort.

Energy assessments and practical design advice will be provided to builders prior to construction of new houses. Using data on the planned building envelope and equipment, along with the expected energy consumption, suggested improvements are given to the builder that could be built into the home's design to improve its expected energy performance. The home is then rated on a scale of 0 - 100 based on its modeled energy performance. Upon completion, a final, as-built inspection and rating will be provided, along with eligible financial incentives.

Specific objectives of the program are:

- Encourage homebuilders to participate in the EnerGuide for New Houses (EGNH) program.
- Increase the number of homes built to high levels of energy efficiency.
- Increase the number of new homes installing Energy Star® labeled products including windows, heating systems, insulation, lighting, appliances, and other measures such as solar hot water heating, and drain-water heat recovery.
- Encourage homebuilders to include additional energy efficient products that may not be captured within the EGNH.
- Create greater market awareness of the benefits of energy efficient new homes and generate greater market demand for their construction.
- Support the establishment and growth of a high performance residential new construction building community, promoting energy efficient design, building materials, equipment and building practices.

The strategies used by the DSM Administrator to achieve these objectives, beyond those already being implemented by Conserve Nova Scotia for their EnerGuide for New Houses program, are expected to include:

- More extensive promotion and marketing of the program
- Provision of, or support for, contractor training and education
- Provision of financial incentives for electrical savings measures

The structure and level of financial incentives for electric savings measures will be determined by the DSM Administrator. The incentive structure will be designed to maximize acquisition of cost effective electrical savings. Incentives may be for individual measures, packages of measures, and/or overall levels of building energy efficiency.

Program design may be modified as appropriate based on program experience in 2009.

2.4.2 Eligible Participants

The program will be available to all builders and owner/builders of new homes throughout the province. While the DSM Plan has the objective of securing cost effective savings and addressing the market barriers to cost effective energy upgrades for all new residential construction, planning for the initial implementation of this program is limited to homes that are eligible for the Conserve Nova Scotia EnerGuide for New Houses program.

2.4.3 Delivery and Implementation

The DSM Administrator will, in collaboration with Conserve Nova Scotia, determine the program management and implementation functions it will conduct with in-house staff, Conserve Nova Scotia and its contractors, and contractors to the DSM Administrator. Any sales and/or installation of energy savings products or measures will be conducted by businesses other than the DSM Administrator.

2.5 Commercial and Industrial Prescriptive Rebate

It is anticipated that the design of the Commercial and Industrial Prescriptive Rebate program would be conducted by the DSM Administrator in 2010, with implementation in the following year. However, the new Administrator may choose to accelerate the design and implementation of this program to increase opportunities for participation, balance the costs and savings of the overall portfolio, or otherwise achieve the objectives of the DSM Plan within the required budget.

2.6 Commercial and Industrial Custom

2.6.1 Description

The Commercial and Industrial (C&I) Custom Program has the objective of securing maximum cost effective energy efficiency savings from large efficiency projects in existing business facilities while helping large C&I customers reduce their electrical energy costs. It provides a combination of technical assistance and financial incentives to enable C&I customers to implement a wide range of cost effective electrical energy saving projects that otherwise would not be implemented.

The program works with eligible customers to identify and implement cost effective electric energy and demand savings measures on a case by case custom basis. Measures of both fundamental types are included:

- Market driven ("lost opportunity") measures, such as planned equipment replacement, renovation, expansion, and equipment replacement on burn-out, where the program can result in higher efficiency choices than would otherwise have been purchased.
- Discretionary retrofit measures, where high efficiency lighting, HVAC equipment, refrigeration, motors, process equipment or building envelope components are replaced prior to the end of their useful lives as a cost effective retrofit (or "early retirement").

Based on preliminary implementation experience in 2008-2009, the following technical and financial assistance components of the program are planned for continuation in 2010:

- Assisting customers in identifying and securing the services of qualified third party sources of technical expertise, or providing technical assistance directly, as may be determined to be needed on a case by case basis

- Cost sharing with customers for the cost of initial scoping studies or audits, as well as subsequent detailed engineering assessments for specific projects
- Providing custom financial incentive offers that cover a portion of the cost of cost effective energy efficiency projects

While the structure and level of financial incentives will be determined by the DSM Administrator, incentives will generally be set at a level deemed reasonable to overcome the incremental cost investment barrier for market-driven measures and the full-cost investment barrier for retrofit projects. The DSM Administrator may also offer financing for the customer share of total project costs to maximize savings within the program budget.

Program design may be modified as appropriate based on program experience in 2009.

2.6.2 Eligible Participants

The C&I Custom program will be available to C&I customers with eligible projects, throughout the province. This program involves a high level of custom analysis, technical assistance, incentive negotiation and savings verification. Accordingly, it needs to be focused on projects of adequate potential savings magnitude to support this level of treatment. This could be managed by the DSM Administrator through targeted outreach to large C&I customers as well as establishment of minimum criteria for project eligibility. In the initial implementation of this program in 2008-2009, it was offered to customers with a typical peak electrical demand of 250 kW or higher and for projects that were expected to save at least 20,000 kWh of electrical energy per year. Typical projects involved lighting, refrigeration, compressed air, industrial processes, motors, and other electrical end uses in large C&I facilities. The DSM Administrator may vary outreach and marketing strategies, project eligibility thresholds and other program design features to increase opportunities for participation, balance the costs and savings of the overall portfolio, or otherwise achieve the objectives of the DSM Plan within the established budget.

2.6.3 Delivery and Implementation

The DSM Administrator will determine the program management and implementation functions it chooses to conduct with in-house staff and which will be performed by implementation contractors or contractors selected by participating customers. Any sales and/or installation of energy savings products or measures will be conducted by businesses other than the DSM Administrator. The Administrator may choose to competitively procure management and/or implementation services, using performance based contracts where an element of contractor compensation is based on achievement of energy savings and other performance goals.

2.7 Small Business Direct Installation

2.7.1 Description

This Small Business Direct Installation program seeks to acquire significant, fast savings through direct installation of energy efficient measures in small business premises, primarily through high performance lighting retrofits. The program contracts with service providers to provide energy efficiency services to small businesses. These range from opportunity identification (the “audit”), to direct installation of energy efficient lighting upgrades, through to environmental disposal/recycling of the old lighting materials.

In the initial program implementation during 2008-2009, typical projects included:

- Upgrade of T12 fluorescent lamps and older technology ballasts to High Performance and low wattage T8 lamps and ballasts (and replacement of old fixtures where appropriate)

- Replacement of High Intensity Discharge (HID) fixtures with High Performance T8 or T5 fixtures
- Replacement of incandescent exit signs with LED exit signs
- CFL retrofits and installation of occupancy sensor lighting controls

As the program evolves, the range and emphasis of lighting technologies may shift, and the new DSM Administrator may seek to expand the range of measures that would be addressed to include selected non-lighting measures, either for direct installation or follow up treatment through another program strategy.

The level of incentives provided for installations will be determined by the DSM Administrator. In 2008-2009, the program incentive covers 80% of the overall project cost.

Program design may be modified as appropriate based on program experience in 2009.

2.7.2 Eligible Participants

The delivery model is one that targets small business customers within a given geographic area. In the long term, it may be desirable to apply this model to a large number of customers throughout the province. In the near term, it will necessarily be limited to selected geographic areas. For 2010, it is planned to expand this program to include six geographic areas (to be determined) across Nova Scotia.

Initial implementation of the program in 2008-2009 was limited to non-residential customers of NSPI having an average peak monthly demand of less than 100 kW, or an annual electricity use of less than 300,000 kWh. This included small retail, convenience and grocery stores, small offices, service stations, restaurants and lodgings, non-profit organizations, small government facilities, institutional and health care facilities, etc. Chains operating multiple facilities in the province and franchise operations are not targeted by this program. Depending on the development of other programs and the timing of their implementation, the DSM Administrator may vary outreach and marketing strategies, project eligibility thresholds, and other program design features to increase opportunities for participation, to balance the costs and savings of the overall portfolio, or otherwise achieve the objectives of the DSM Plan within the established budget.

2.7.3 Delivery and Implementation

The DSM Administrator will determine the program management and implementation functions it chooses to conduct with in-house staff and which will be performed by implementation contractors. Any sales and/or installation of energy savings products or measures will be conducted by businesses other than the DSM Administrator. Given the particular nature of this program, it is suited to one or more turn-key labour and materials contracts which is the approach in 2008-2009.

2.8 Commercial and Industrial New Construction

2.8.1 Description

The most cost effective way to influence the energy efficiency of buildings is to do so when new buildings are being designed and constructed, as these early decisions affect a building's energy consumption for its full life. The objective of this program is to secure maximum cost effective savings in this market. This is a complex program that will require considerable detailed design during 2009, with anticipated implementation beginning in 2010. There may be two participation paths, a "Custom Path" and a "Comprehensive Building Design Path."

Custom Path:

The C&I Custom Path would allow customers to request technical assistance to qualify measures to receive an incentive that is based on the results of a cost and savings analysis for individual, or packages of, energy efficiency measures. This path may be particularly suited to smaller and simpler C&I new construction projects. Custom Path program incentives may be based on the practices of the C&I Custom program for existing buildings. As prescriptive C&I measures become a feature of the C&I program portfolio, they could also be available through this path.

Comprehensive Building Design Path:

A Comprehensive Building Design Path would allow the customer, the design team, and program supported experts to work together from the conceptual design stages of a new construction or substantial renovation project. Holistic design and equipment options would be considered in order to improve the overall energy performance of a building.

A Comprehensive Building Design Path would provide technical support and incentives for building owners to pursue of high-efficiency options that integrate building envelope, lighting, and mechanical systems. The combination of technical consultation and incentives provided by the program will cover a significant portion of the additional design, modeling, and equipment costs required to turn an average building into an exemplary one.

Under either path, the customer may also be provided with a range of technical assistance, plan review and building commissioning services.

Establishing accurate baseline efficiency levels is critical to establishing program savings as well as determining appropriate incentives. In the absence of an energy code that reflects current market conditions, the Administrator may complete a detailed baseline study of new construction.

2.8.2 Eligible Participants

The program will target all new C&I buildings, as well as substantial renovations, throughout the province.

2.8.3 Delivery and Implementation

The DSM Administrator will determine the program management and implementation functions it chooses to conduct with in-house staff, and which may be provided by Program Implementation contractors, or provided in cooperation with other programs addressing C&I new construction. Any sales and/or installation of energy savings products or measures will be conducted by businesses other than the DSM Administrator. As in the C&I Custom program, the DSM Administrator may choose to qualify a pool of third party technical assistance service providers who can consult to the program and to building owners on specific projects.

2.9 Education and Outreach

2.9.1 Description

A key to achieving performance targets for energy reductions is customer awareness of the value of energy efficiency, which will lead to taking customer energy efficiency actions through the DSM program portfolio. Systematic education and outreach efforts are an important undertaking to affect customer knowledge and perceptions, as well as to encourage higher levels of participation in DSM programs. Accordingly this program will:

- provide general energy efficiency information to consumers on ways to conserve energy, reduce peak demand, achieve cost effective energy savings and lower their electric utility bills,
- Conduct activities that increase public awareness of the value of energy efficiency and the value of participating in DSM programs.
- Connect customers to appropriate DSM programs and services.

Among the options that the DSM Administrator may develop and implement as part of this program are:

- Provision of general energy efficiency information, assistance and referrals through a central, toll-free telephone call center.
- Establishment and maintenance of a web site with general energy efficiency information, assistance and links to other resources.
- Production and distribution of written energy efficiency materials.
- Provision of on-line energy analysis software and other energy savings calculators.
- Development of classroom curriculum.
- Public speaking and presentations on energy efficiency.
- Development and placement of stories in the media on energy efficiency.

Any savings resulting from the Education and Outreach Program will be captured via participation in the other DSM programs.

2.9.2 Eligible Participants

The target market for Education and Outreach Program is all Nova Scotians. This includes owners and renters living in all housing types, from single family to multi-family dwellings, as well as C&I customers. Additionally, education and outreach programs may be developed and implemented in educational institutions, from schools to vocational programs, and institutions of higher education.

2.9.3 Delivery and Implementation

The DSM Administrator will determine the program management and implementation functions it will conduct with in-house staff, and which may be provided by program implementation contractors, or provided in cooperation with other programs addressing energy outreach and education, including educational institutions and Conserve Nova Scotia.

2.10 Development and Research

2.10.1 Description

Activities conducted under this program will explore and evaluate opportunities for future DSM programming. This may include activities such as market assessments, baseline evaluations and demonstration projects. Although energy and demand savings are not assigned to this program, it is anticipated that the cost effectiveness of other DSM programs would be improved over time through the Development and Research program. The DSM Administrator will develop a plan to focus attention on emerging energy efficiency strategies and technologies. It would be expected to include maintaining awareness of energy efficiency strategy and technology development, as well as evaluation results, in other jurisdictions.

2.10.2 Delivery and Implementation

The DSM Administrator will determine the Development and Research program management and implementation functions it will conduct with in-house staff, contractors, or in cooperation with other programs or institutions addressing energy efficiency, including educational institutions and Conserve Nova Scotia.

Attachment 1

DSM Plan Technical Tables

Following are measure characterizations for each subsector and market, and 2010 Plan results for each program, first for the Residential sector, and then for the Commercial and Industrial sector.

Table 2-1 Measure Characterization--Residential--Single Family--New

Measure Name --savings at generator --2010 $	A Measure Life (Years)	B Average Peak Demand Savings per Unit (kW)	C 'Average Annual Energy Savings per Unit (kWh)	D Incremental Measure Cost ($)	E Incremental Measure Cost ($/kW)	F Avoided Cost Benefits ($/kW)	G Program Admin. Cost ($/kW)	H=F/(E+G) TRC
Lighting								
CFL, 6.0 hr/day	5	0.009	136	$3	$366	$5,597	$559	6.1
CFL, 0.5 hr/day	7	0.007	11	$3	$458	$1,041	$559	1.0
CFL, 2.5 hr/day	7	0.009	57	$3	$366	$3,245	$559	3.5
LED nightlights	10	0.009	13	$3	$366	$1,359	$559	1.5
LED holiday lights	10	0.078	14	$10	$122	$604	$559	0.9
Heating/HVAC and Building Envelope								
ENERGY STAR or better Air Source Heat Pump, SEER=18; HSPF=9.4	18	0.0002	2,199	$955	$5,493,120	$12,175,068	$1,117	2.2
Duct Sealing and insulation	15	0.596	1,336	$573	$961	$2,594	$1,117	1.2
Ceiling insulation (R-20 improved to R-40)	30	0.420	941	$1,008	$2,399	$4,273	$1,117	1.2
High Efficiency Windows, Low-e; U=0.35	30	0.544	1,221	$849	$1,559	$4,276	$1,117	1.6
Floor insulation (R-10 to R-20)	30	0.172	502	$756	$4,386	$5,174	$1,117	0.9
Wall insulation (R-10 to R-20)	30	0.320	717	$955	$2,985	$4,273	$1,117	1.0
Programmable thermostat	15	0.174	178	$32	$183	$1,600	$1,117	1.2
ENERGY STAR or better Air Source Heat Pump, SEER=14; HSPF=8.5	18	0.0002	1,402	$849	$4,882,774	$7,763,374	$1,117	1.6
Water Heating								
HE Water Heater (EF=0.95)	15	0.037	293	$85	$2,325	$7,321	$559	2.5
Energy Star Dish Washer (EF=0.58)	13	0.054	111	$134	$2,481	$2,159	$559	0.7
Horizontal-Axis Clothes Washer: Energy Star CW (EF=2.5)	14	0.191	534	$531	$2,774	$2,864	$559	0.9
Faucet Aerators	15	0.047	38	$5	$113	$1,421	$559	2.1
Hot water pipe insulation	15	0.045	85	$2	$47	$2,292	$559	3.8
Drain water heat recovery	20	0.184	1,033	$605	$3,282	$6,844	$559	1.8
Solar Assisted Water Heating	15	0.496	2,783	$2,653	$5,347	$5,347	$559	0.9
Refrigeration and Miscellaneous								
High Efficiency Dryer With Moisture Sensor	14	0.018	102	$64	$3,487	$5,030	$1,117	1.1
ENERGY STAR or better Refrigerator	15	0.015	82	$72	$4,913	$5,347	$1,117	0.9

Table 2-2 Measure Characterization--Residential--Single Family--Existing

Measure Name --savings at generator --2010 $	A Measure Life (Years)	B Average Peak Demand Savings per Unit (kW)	C Average Annual Energy Savings per Unit (kWh)	D Incremental Measure Cost ($)	E Incremental Measure Cost ($/kW)	F Avoided Cost Benefits ($/kW)	G Program Admin. Cost ($/kW)	H=F/(E+G) TRC
Lighting								
CFL, 6.0 hr/day	5	0.009	136	$3	$366	$5,597	$524	6.3
CFL, 0.5 hr/day	7	0.007	11	$3	$458	$1,041	$524	1.1
CFL, 2.5 hr/day	7	0.009	57	$3	$366	$3,245	$524	3.6
Ceiling halogen fixtures to CFL	15	0.032	152	$83	$2,580	$4,622	$524	1.5
Halogen torchiere to CFL	10	0.063	298	$47	$741	$3,217	$524	2.5
LED nightlights	10	0.009	13	$3	$366	$1,359	$524	1.5
Heating/HVAC and Building Envelope								
ENERGY STAR or better Air Source Heat Pump, SEER=14; HSPF=8.5	18	0.000	1,541	$849	$4,882,774	$8,531,092	$1,048	1.7
Duct Insulation and Sealing	30	0.596	1,336	$573	$961	$4,273	$1,048	2.1
Ceiling insulation (R-20 improved to R-40)	30	0.323	724	$2,016	$6,238	$4,273	$1,048	0.6
High Efficiency Windows, Low-e; U=0.35	30	0.544	1,221	$849	$1,559	$4,276	$1,048	1.6
Ceiling insulation (R-0 improved to R-20)	30	3.404	7,627	$2,016	$592	$4,273	$1,048	2.6
Floor insulation (R-0 to R-20)	30	0.479	1,074	$1,512	$3,156	$4,273	$1,048	1.0
Wall insulation (R-0 to R-20)	30	2.305	5,163	$1,910	$829	$4,273	$1,048	2.3
Programmable thermostat	15	0.174	178	$32	$183	$1,600	$183	4.4
ENERGY STAR or better Air Source Heat Pump, SEER=18; HSPF=9.4	18	0.000	2,404	$955	$5,493,120	$13,306,002	$1,048	2.4
Water Heating								
HE Water Heater (EF=0.95)	15	0.037	293	$85	$2,319	$7,321	$524	2.6
Energy Star Dish Washer (EF=0.58)	13	0.054	111	$134	$2,484	$2,159	$524	0.7
Horizontal-Axis Clothes Washer: Energy Star CW (EF=2.5)	14	0.191	534	$531	$2,774	$2,864	$524	0.9
Faucet Aerators	15	0.047	38	$5	$113	$1,421	$524	2.2
Hot water pipe insulation	15	0.045	85	$2	$47	$2,292	$524	4.0
Drain water heat recovery	20	0.184	1,033	$605	$3,282	$6,844	$524	1.8
Low flow showerheads	7	0.047	227	$7	$158	$2,479	$524	3.6
Solar Assisted Water Heating	15	0.496	2,783	$2,653	$5,347	$5,347	$524	0.9
Refrigeration and Miscellaneous								
Remove secondary refigerator/freezer	10	0.238	1,336	$119	$501	$3,728	$524	3.6
Energy-Star Dehumidifier	11	0.028	433	$312	$11,172	$10,314	$524	0.9

Table 2-3 2010--Residential--Efficient Products

Measure Name --savings at generator --2010 $	For Plan Year 2010 A Achievable Potential Peak Demand Savings (kW)	B Achievable Potential First Year Energy Savings (kWh)	C Achievable Potential Lifetime Energy Savings (kWh)	D Total Avoided Cost Benefits ($)	E TRC Costs ($)	F=D-E Total Net Resource Benefits ($)	G=D/E TRC
Lighting							
CFL, 6.0 hr/day	30.5	479,510	2,397,550	170,926	27,180	143,746	6.3
CFL, 0.5 hr/day	23.8	38,993	272,952	24,818	23,401	1,417	1.1
CFL, 2.5 hr/day	30.2	197,600	1,383,202	98,011	26,881	71,130	3.6
Ceiling halogen fixtures to CFL	290.3	1,370,199	20,552,991	1,341,670	901,147	440,523	1.5
Halogen torchiere to CFL	915.9	4,323,106	43,231,059	2,946,375	1,158,620	1,787,755	2.5
LED nightlights	121.7	182,057	1,820,575	165,454	108,356	57,099	1.5
Subtotal	**1,412.6**	**6,591,466**	**69,658,328**	**4,747,254**	**2,245,585**	**2,501,669**	**2.1**
Refrigeration and Miscellaneous							
Remove secondary refigerator/freezer	236.3	1,324,842	13,248,419	880,829	242,173	638,656	3.6
Energy-Star Dehumidifier	30.7	476,662	5,243,278	316,966	359,429	-42,463	0.9
Energy Star Dish Washer (EF=0.58)	39.3	81,206	1,055,673	84,893	118,264	-33,371	0.7
Horizontal-Axis Clothes Washer: Energy Star CW (EF=2.5)	139.7	390,096	5,461,346	399,991	460,590	-60,599	0.9
Subtotal	**446.0**	**2,272,805**	**25,008,716**	**1,682,679**	**1,180,457**	**502,222**	**1.4**
Residential -- Efficient Products Total	**1,858.6**	**8,864,271.3**	**94,667,043**	**6,429,933**	**3,426,042**	**3,003,892**	**1.9**

Table 2-4 2010--Residential—Existing Houses

Measure Name --savings at generator --2010 $	For Plan Year 2010 A Achievable Potential Peak Demand Savings (kW)	B Achievable Potential First Year Energy Savings (kWh)	C Achievable Potential Lifetime Energy Savings (kWh)	D Total Avoided Cost Benefits ($)	E TRC Costs ($)	F=D-E Total Net Resource Benefits ($)	G=D/E TRC
Heating/HVAC and Building Envelope							
ENERGY STAR or better Air Source Heat Pump, SEER=14; HSPF=8.5	0.1	608,637	10,955,473	585,845	335,381	250,464	1.7
Duct Insulation and Sealing	58.4	130,801	3,924,028	249,469	117,280	132,189	2.1
Ceiling insulation (R-20 improved to R-40)	8.4	18,913	567,385	36,071	61,500	-25,429	0.6
High Efficiency Windows, Low-e; U=0.35	213.3	478,278	14,348,339	911,954	556,003	355,951	1.6
Ceiling insulation (R-0 improved to R-20)	88.9	199,186	5,975,568	379,895	145,790	234,105	2.6
Floor insulation (R-0 to R-20)	125.2	280,398	8,411,953	534,787	526,034	8,754	1.0
Wall insulation (R-0 to R-20)	120.4	269,682	8,090,474	514,349	225,866	288,483	2.3
Programmable thermostat	214.4	219,616	3,294,246	343,033	78,571	264,462	4.4
ENERGY STAR or better Air Source Heat Pump, SEER=18; HSPF=9.4	0.0	80,964	1,457,360	77,930	32,178	45,752	2.4
Subtotal	**829.0**	**2,286,476**	**57,024,825**	**3,633,333**	**2,078,602**	**1,554,731**	**1.7**
Water Heating							
HE Water Heater (EF=0.95)	27.0	216,727	3,250,900	197,805	76,813	120,992	2.6
Energy Star Dish Washer (EF=0.58)	32.5	67,077	872,006	70,123	97,689	-27,566	0.7
Horizontal-Axis Clothes Washer: Energy Star CW (EF=2.5)	115.4	322,227	4,511,179	330,400	380,456	-50,056	0.9
Faucet Aerators	23.2	18,667	280,011	32,917	14,747	18,170	2.2
Hot water pipe insulation	27.9	52,159	782,383	63,898	15,909	47,989	4.0
Drain water heat recovery	220.6	1,236,977	24,739,543	1,509,794	839,578	670,216	1.8
Low flow showerheads	32.8	158,830	1,111,808	81,404	22,397	59,006	3.6
Solar Assisted Water Heating	102.0	571,860	8,577,907	545,331	598,665	-53,334	0.9
Subtotal	**581.3**	**2,644,525**	**44,125,737**	**2,831,673**	**2,046,255**	**785,418**	**1.4**
Residential -- Existing Houses Total	**1,410.3**	**4,931,001**	**101,150,563**	**6,465,006**	**4,124,857**	**2,340,149**	**1.6**

Table 2-5 2010--Residential—Low Income

	For Plan Year 2010						
Measure Name --savings at generator --2010 $	**A Achievable Potential Peak Demand Savings (kW)**	**B Achievable Potential First Year Energy Savings (kWh)**	**C Achievable Potential Lifetime Energy Savings (kWh)**	**D Total Avoided Cost Benefits ($)**	**E TRC Costs ($)**	**F=D-E Total Net Resource Benefits ($)**	**G=D/E TRC**
Lighting							
CFL, 6.0 hr/day	143.5	2,252,731	11,263,656	803,006	148,734	654,273	5.4
CFL, 2.5 hr/day	141.9	928,323	6,498,263	460,457	147,099	313,357	3.1
Subtotal	**285.4**	**3,181,054**	**17,761,919**	**1,263,463**	**295,833**	**967,630**	**4.3**
Heating/HVAC and Building Envelope							
Duct Insulation and Sealing	51.1	114,451	3,433,524	218,285	117,603	100,682	1.9
Ceiling insulation (R-20 improved to R-40)	7.4	16,549	496,462	31,562	55,979	-24,417	0.6
High Efficiency Windows, Low-e; U=0.35	186.6	418,493	12,554,797	797,960	541,243	256,716	1.5
Ceiling insulation (R-0 improved to R-20)	77.8	174,287	5,228,622	332,408	150,384	182,024	2.2
Floor insulation (R-0 to R-20)	109.5	245,349	7,360,459	467,939	492,400	-24,461	1.0
Wall insulation (R-0 to R-20)	105.3	235,972	7,079,164	450,056	228,526	221,530	2.0
Programmable thermostat	187.6	192,164	2,882,465	300,154	78,381	221,773	3.8
Subtotal	**725.3**	**1,397,265**	**39,035,494**	**2,598,364**	**1,664,516**	**933,847**	**1.6**
Water Heating							
Faucet Aerators	20.3	16,334	245,010	28,803	15,876	12,927	1.8
Hot water pipe insulation	24.4	45,639	684,585	55,911	17,498	38,413	3.2
Low flow showerheads	28.7	138,976	972,832	71,228	23,812	47,416	3.0
Subtotal	**73.4**	**200,949**	**1,902,426.9**	**155,942**	**57,185**	**98,757**	**2.7**
Remove secondary refigerator/freezer	86.2	483,237	4,832,368	321,283	100,971	220,312	3.2
Residential -- Low Income Total	**1,170.3**	**5,262,505**	**63,532,207**	**4,339,051**	**2,118,506**	**2,220,545**	**2.0**

Table 2-6 2010--Residential—New Homes

	For Plan Year 2010						
	A	B	C	D	E	F=D-E	G=D/E
Measure Name --savings at generator --2010 $	Achievable Potential Peak Demand	Achievable Potential First Year Energy	Achievable Potential Lifetime Energy	Total Avoided Cost Benefits ($)	TRC Costs ($)	Total Net Resource Benefits ($)	TRC
Lighting							
CFL, 6.0 hr/day	69.2	1,086,747	5,433,735	387,381	64,017	323,364	6.1
CFL, 0.5 hr/day	249.1	407,393	2,851,748	259,297	253,188	6,109	1.0
CFL, 2.5 hr/day	68.4	447,306	3,131,142	221,868	63,239	158,629	3.5
LED nightlights	38.3	57,255	572,552	52,034	35,414	16,620	1.5
LED holiday lights	172.3	31,863	318,629	104,066	117,297	-13,231	0.9
Subtotal	**597.3**	**2,030,564**	**12,307,805**	**1,024,645**	**533,154**	**491,490**	**1.9**
Heating/HVAC and Building Envelope							
ENERGY STAR or better Air Source Heat Pump, SEER=18; HSPF=9.4	0.0	310,461	5,588,295	298,825	134,851	163,975	2.2
Duct Sealing and insulation	143.1	320,514	4,807,714	371,128	297,373	73,756	1.2
Ceiling insulation (R-20 improved to R-40)	94.9	212,637	6,379,114	405,550	333,752	71,798	1.2
High Efficiency Windows, Low-e; U=0.35	123.0	275,758	8,272,738	525,800	329,159	196,640	1.6
Floor insulation (R-10 to R-20)	38.9	113,399	3,401,976	201,437	214,281	-12,844	0.9
Wall insulation (R-10 to R-20)	72.3	161,891	4,856,734	308,765	296,459	12,307	1.0
Programmable thermostat	157.1	160,886	2,413,284	251,298	204,287	47,011	1.2
ENERGY STAR or better Air Source Heat Pump, SEER=14; HSPF=8.5	0.0	65,985	1,187,734	63,515	39,957	23,558	1.6
Subtotal	**629.2**	**1,621,531**	**36,907,589**	**2,426,319**	**1,850,119**	**576,200**	**1.3**
Water Heating							
HE Water Heater (EF=0.95)	10.5	84,346	1,265,188	76,982	30,323	46,660	2.5
Energy Star Dish Washer (EF=0.58)	18.4	38,070	494,912	39,799	56,037	-16,238	0.7
Horizontal-Axis Clothes Washer: Energy Star CW (EF=2.5)	32.4	90,498	1,266,974	92,794	107,983	-15,190	0.9
Faucet Aerators	15.8	12,714	190,706	22,419	10,595	11,824	2.1
Hot water pipe insulation	15.2	28,419	426,284	34,815	9,199	25,617	3.8
Drain water heat recovery	60.1	336,985	6,739,708	411,308	230,822	180,486	1.8
Solar Assisted Water Heating	11.9	66,774	1,001,607	63,676	70,320	-6,643	0.9
Subtotal	**164.3**	**657,806**	**11,385,379**	**741,793**	**515,277**	**226,516**	**1.4**
Refrigeration and Miscellaneous							
High Efficiency Dryer With Moisture Sensor	4.4	24,779	346,910	22,228	20,346	1,882	1.1
ENERGY STAR or better Refrigerator	7.0	39,530	592,951	37,696	42,512	-4,815	0.9
Subtotal	**11.5**	**64,309**	**939,861**	**59,925**	**62,858**	**-2,933**	**1.0**
Residential -- New Houses Total	**1,402.3**	**4,374,210**	**61,540,634**	**4,252,680**	**2,961,407**	**1,291,273**	**1.4**

Table 2-7 Measure Characterization--Commercial—New

Measure Name --savings at generator --2010 $	A Measure Life (Years)	B Average Peak Demand Savings per Unit (kW)	C Average Annual Energy Savings per Unit (kWh)	D Incremental Measure Cost ($)	E Incremental Measure Cost ($/kW)	F Avoided Cost Benefits ($/kW)	G Program Admin. Cost ($/kW)	H=F/(E+G) TRC
Commercial Lighting								
CFLs	8	0.040	296	11	285	3,993	292	6.9
T8 or T5 w/ EB	20	0.022	162	48	2,190	8,703	292	3.5
Delamping w/ Reflectors	20	0.039	285	22	575	8,703	292	10.0
LED Exit Signs	20	0.024	240	52	2,123	11,294	292	4.7
Occupancy Sensors	12	0.033	600	114	3,499	13,094	292	3.5
Daylighting	15	0.407	3,002	1,019	2,506	6,799	292	2.4
Commercial Heating/HVAC and Building Envelope								
Hi-E Air-Cooled Chillers	20	0.069	105	73	1,067	2,576	834	1.4
Hi-E Water-Cooled Chillers	20	0.033	50	53	1,618	2,593	834	1.1
Programmable Thermostats	20	0.171	700	256	1,494	5,249	834	2.3
Energy Mgmt System	20	1.310	3,500	732	559	3,770	834	2.7
Commercial Custom								
Hi-E Evaporator Fan Motors	15	0.014	61	22	1,536	4,208	333	2.3
Hi-E Refrigeration Compressors	15	0.097	408	619	6,390	4,208	333	0.6
Hi-E Ice Makers	12	0.084	352	183	2,192	3,461	333	1.4
Strip Curtains	4	0.036	389	27	762	3,192	333	2.9
Night Covers	4	0.000	313	64	374,240	518,138	333	1.4
Premium Efficiency Motors (HP)	15	0.023	93	11	458	4,043	417	4.6
Variable Frequency Drives (HP)	15	0.156	626	295	1,894	4,043	417	1.7

Table 2-8 Measure Characterization--Commercial—Existing

Measure Name --savings at generator --2010 $	A Measure Life (Years)	B Average Peak Demand Savings per Unit (kW)	C Average Annual Energy Savings per Unit (kWh)	D Incremental Measure Cost ($)	E Incremental Measure Cost ($/kW)	F Avoided Cost Benefits ($/kW)	G Program Admin. Cost ($/kW)	H=F/(E+G) TRC
Commercial Refrigeration								
Hi-E Evaporator Fan Motors	15	0.065	273	84	1,300	4,897	278	3.1
Strip Curtains	4	0.036	389	27	762	3,803	278	3.7
Night Covers	4	0.000	313	64	374,240	621,739	278	1.7
Commercial Motors								
Premium Efficiency Motors	15	0.023	98	95	4,071	4,910	347	1.1
Variable Frequency Drives (VFDs)	15	0.156	659	295	1,894	4,910	347	2.2
Lighting								
CFLs	8	0.046	302	11	249	2,312	851	2.1
Premium T8 w/ EB	20	0.036	237	66	1,850	5,112	851	1.9
Delamping w/ Reflectors	20	0.044	291	44	1,004	5,112	851	2.8
LED Exit Signs	20	0.027	245	103	3,789	6,622	851	1.4
Occupancy Sensors	12	0.037	613	114	3,055	7,296	851	1.9
Daylighting	15	0.466	3,069	1,019	2,188	3,995	851	1.3

Table 2-9 Measure Characterization--Industrial--New

Measure Name --savings at generator --2010 $	A 'Measure Life (Years)	B Average Peak Demand Savings per Unit (kW)	C 'Average Annual Energy Savings per Unit (kWh)	D Incremental Measure Cost ($)	E Incremental Measure Cost ($/kW)	F Avoided Cost Benefits ($/kW)	G Program Admin. Cost ($/kW)	H=F/(E+G) TRC
Industrial Lighting								
CFLs	8	0.084	391	11	137	2,668	292	6.2
T8 or T5 w/ EB	20	0.136	635	246	1,814	5,874	292	2.8
Delamping w/ Reflectors	20	0.080	376	22	276	5,874	292	10.4
LED Exit Signs	20	0.050	254	52	1,040	6,324	292	4.7
Occupancy Sensors	12	0.154	1,799	227	1,480	8,526	292	4.8
PS Metal Halides	8	0.215	1,008	74	343	2,668	292	4.2
Industrial HVAC								
Air-Cooled Chillers	20	0.069	131	73	1,067	2,977	834	1.6
Water-Cooled Chillers	20	0.033	63	53	1,601	2,977	834	1.2
Industrial Custom								
Premium Efficiency Motors	15	0.023	102	11	458	4,355	417	5.0
Variable Frequency Drives (VFDs)	15	0.156	685	295	1,894	4,354	417	1.9
Hi-E Air Compressors	15	63	2,215,899	64,092	1,019	29,574	333	21.9

Table 2-10 Measure Characterization--Industrial—Existing

Measure Name --savings at generator --2010 $	A Measure Life (Years)	B Average Peak Demand Savings per Unit (kW)	C Average Annual Energy Savings per Unit (kWh)	D Incremental Measure Cost ($)	E Incremental Measure Cost ($/kW)	F Avoided Cost Benefits ($/kW)	G Program Admin. Cost ($/kW)	H=F/(E+G) TRC
Industrial Lighting								
T5 w/ EB	20	0.136	635	246	1,814	6,854	243	3.3
Delamping w/ Reflectors	20	0.080	376	22	276	6,854	243	13.2
LED Exit Signs	20	0.050	254	52	1,040	7,395	243	5.8
Occupancy Sensors	12	0.154	1,799	227	1,480	10,109	243	5.9
PS Metal Halides	8	0.215	1,008	74	343	3,127	243	5.3
Industrial Motors								
Premium Efficiency Motors	15	0.021	90	11	499	4,897	347	5.8
Variable Frequency Drives (VFDs)	15	0.143	685	295	2,063	5,455	347	2.3
Industrial Air Compressors								
Hi-E Air Compressors	15	62.887	2,215,899	64,092	1,019	35,336	278	27.2
Industrial Custom								
Custom	20	133,271	609,391,020	0	1,665	6,718	556	3.0

Table 2-11 2010--Commercial & Industrial--New Construction

Measure Name --savings at generator --2010 $	For Plan Year 2010 A Achievable Potential Peak Demand Savings (kW)	B Achievable Potential First Year Energy Savings (kWh)	C Achievable Potential Lifetime Energy Savings (kWh)	D Total Avoided Cost Benefits ($)	E TRC Costs ($)	F=D-E Total Net Resource Benefits ($)	G=D/E TRC
Commercial Lighting							
CFLs	80.1	591,416	4,731,331	319,897	46,211	273,686	6.9
T8 or T5 w/ EB	89.6	661,204	13,224,081	779,470	222,294	557,175	3.5
Delamping w/ Reflectors	12.9	95,362	1,907,250	112,419	11,194	101,225	10.0
LED Exit Signs	8.5	84,076	1,681,523	96,335	20,596	75,739	4.7
Occupancy Sensors	4.6	84,310	1,011,718	59,814	17,316	42,498	3.5
Daylighting	56.3	415,373	6,230,590	382,527	157,442	225,085	2.4
Subtotal	**252.0**	**1,931,742**	**28,786,493**	**1,750,461**	**475,053**	**1,275,408**	**3.7**
Commercial Heating/HVAC and Building Envelope							
Hi-E Air-Cooled Chillers	3.1	4,691	93,824	7,891	5,823	2,068	1.4
Hi-E Water-Cooled Chillers	1.5	2,252	45,035	3,773	3,567	206	1.1
Programmable Thermostats	75.3	307,702	6,154,044	395,470	175,388	220,082	2.3
Energy Mgmt System	77.4	206,816	4,136,325	291,836	107,775	184,061	2.7
Subtotal	**157.3**	**521,461**	**10,429,228**	**698,970**	**292,553**	**406,417**	**2.4**
Commercial Custom							
Hi-E Evaporator Fan Motors	1.3	5,495	82,423	5,487	2,438	3,049	2.3
Hi-E Refrigeration Compressors	8.7	36,835	552,527	36,783	58,780	-21,997	0.6
Hi-E Ice Makers	7.6	32,158	385,892	26,412	19,274	7,138	1.4
Strip Curtains	1.8	19,607	78,429	5,811	1,994	3,817	2.9
Night Covers	0.0	6,308	25,234	1,792	1,295	496	1.4
Premium Efficiency Motors (HP)	1.9	7,628	114,420	7,686	1,663	6,023	4.6
Variable Frequency Drives (HP)	12.7	51,108	766,613	51,498	29,438	22,060	1.7
Subtotal	**34.1**	**159,139**	**2,005,538**	**135,470**	**114,882**	**20,588**	**1.2**
Industrial Lighting							
CFLs	49.5	231,760	1,854,083	132,117	21,212	110,905	6.2
T8 or T5 w/ EB	102.8	481,091	9,621,820	603,710	216,393	387,316	2.8
Delamping w/ Reflectors	16.0	74,740	1,494,802	93,790	9,058	84,731	10.4
LED Exit Signs	11.3	57,759	1,155,187	71,472	15,053	56,419	4.7
Occupancy Sensors	3.4	40,331	483,967	29,383	6,105	23,278	4.8
PS Metal Halides	9.0	41,944	335,550	23,910	5,689	18,221	4.2
Subtotal	**192.0**	**927,625**	**14,945,409**	**954,382**	**273,512**	**680,870**	**3.5**
Industrial HVAC							
Air-Cooled Chillers	2.3	4,343	86,862	6,754	4,313	2,441	1.6
Water-Cooled Chillers	1.1	2,085	41,694	3,242	2,651	591	1.2
Subtotal	**3.4**	**6,428**	**128,556**	**9,996**	**6,964**	**3,032**	**1.4**
Industrial Custom							
Premium Efficiency Motors	28.2	123,742	1,856,134	122,646	24,641	98,005	5.0
Variable Frequency Drives (VFDs)	188.7	828,684	12,430,254	821,411	436,059	385,352	1.9
Hi-E Air Compressors	5.7	201,841	3,027,614	169,405	7,748	161,656	21.9
Custom	516.1	2,359,967	47,199,341	2,973,085	1,203,409	1,769,676	2.5
Subtotal	**738.7**	**3,514,234**	**64,513,342**	**4,086,546**	**1,671,857**	**2,414,689**	**2.4**
C&I - New Construction Total	**1,377.4**	**7,060,629**	**120,808,568**	**7,635,824**	**2,834,820**	**4,801,004**	**2.7**

Table 2-12 2010--Commercial & Industrial--Small Business Direct Install Lighting

	For Plan Year 2010						
Measure Name --savings at generator --2010 $	**A Achievable Potential Peak Demand Savings (kW)**	**B Achievable Potential First Year Energy Savings (kWh)**	**C Achievable Potential Lifetime Energy Savings (kWh)**	**D Total Avoided Cost Benefits ($)**	**E TRC Costs ($)**	**F=D-E Total Net Resource Benefits ($)**	**G=D/E TRC**
CFLs	801.5	3,168,739	25,349,914	1,852,836	881,625	971,210	2.1
Premium T8 w/ EB	1,337.6	5,288,217	105,764,348	6,838,182	3,613,369	3,224,813	1.9
Delamping w/ Reflectors	306.9	1,213,485	24,269,699	1,569,155	569,324	999,831	2.8
LED Exit Signs	434.5	2,344,461	46,889,226	2,877,496	2,016,257	861,239	1.4
Occupancy Sensors	50.8	501,672	6,020,068	370,315	198,264	172,051	1.9
Daylighting	370.1	1,463,104	21,946,565	1,478,449	1,124,875	353,573	1.3
C&I - Small Business Direct Install Lighting	**3,301.4**	**13,979,680**	**230,239,819**	**14,986,431**	**8,403,714**	**6,582,717**	**1.8**

Table 2-13 2010--Commercial & Industrial—Custom

	For Plan Year 2010						
Measure Name --savings at generator --2010 $	A Achievable Potential Peak Demand Savings (kW)	B Achievable Potential First Year Energy Savings (kWh)	C Achievable Potential Lifetime Energy Savings (kWh)	D Total Avoided Cost Benefits ($)	E TRC Costs ($)	F=D-E Total Net Resource Benefits ($)	G=D/E TRC
Commercial Refrigeration							
Hi-E Evaporator Fan Motors	38.8	196,187	2,942,808	189,993	61,214	128,779	3.1
Strip Curtains	12.7	163,957	655,826	48,255	13,189	35,066	3.7
Night Covers	0.0	52,751	211,005	14,983	9,026	5,958	1.7
Subtotal	**51.5**	**412,895**	**3,809,639**	**253,232**	**83,429**	**169,803**	**3.0**
Commercial Motors							
Premium Efficiency Motors	19.6	99,296	1,489,438	96,114	86,486	9,628	1.1
Variable Frequency Drives (VFDs)	131.2	665,282	9,979,236	643,964	294,031	349,932	2.2
Subtotal	**150.7**	**764,578**	**11,468,675**	**740,078**	**380,518**	**359,560**	**1.9**
Industrial Lighting							
T5 w/ EB	1,200.0	6,740,580	134,811,596	8,225,239	2,468,217	5,757,021	3.3
Delamping w/ Reflectors	186.4	1,047,185	20,943,708	1,277,835	96,699	1,181,136	13.2
LED Exit Signs	132.0	809,268	16,185,356	975,731	169,338	806,393	5.8
Occupancy Sensors	40.2	565,073	6,780,873	406,771	69,325	337,446	5.9
PS Metal Halides	104.6	587,676	4,701,405	327,205	61,342	265,864	5.3
Subtotal	**1,663.2**	**9,749,781**	**183,422,938**	**11,212,781**	**2,864,921**	**8,347,861**	**3.9**
Industrial Motors							
Premium Efficiency Motors	266.3	1,346,555	20,198,323	1,304,040	225,377	1,078,663	5.8
Variable Frequency Drives (VFDs)	1,784.3	10,240,269	153,604,035	9,733,272	4,300,339	5,432,933	2.3
Subtotal	**2,050.6**	**11,586,824**	**173,802,357.8**	**11,037,312**	**4,525,716**	**6,511,596**	**2.4**
Industrial Air Compressors							
Hi-E Air Compressors	55.9	2,362,929	35,443,938	1,974,681	72,484	1,902,197	27.2
Subtotal	**55.9**	**2,362,929**	**35,443,937.9**	**1,974,681**	**72,484**	**1,902,197**	**27.2**
Industrial Custom							
Custom	2,427.0	13,317,227	338,860,730	16,305,069	5,389,208	10,915,861	3.0
Subtotal	**2,427.0**	**13,317,227**	**338,860,730**	**16,305,069**	**5,389,208**	**10,915,861**	**3.0**
C&I - Custom Total	**6,399.0**	**38,194,235**	**746,808,279**	**41,523,153**	**13,316,276**	**28,206,877**	**3.1**

Appendix D

Correspondence Regarding DSM Environmental Credits

HALIFAX
REGIONAL MUNICIPALITY

P.O. Box 1749
Halifax, Nova Scotia
B3J 3A5 Canada

January 30, 2009

RECEIVED
FEB - 2 2009
Nova Scotia
Utility and Review Board

Nancy McNeil
Regulatory Affairs Officer/Clerk
Nova Scotia Utility and Review Board
1601 Lower Water Street, Suite 300
PO Box 1692, Postal Unit M
Halifax, NS B3J 3S3

Dear Ms McNeil:

RE: Demand Side Management Program Application

As a result of the DSM Settlement Agreement, to which the Halifax Regional Municipality was a signatory, Nova Scotia Power Incorporated initiated a $12.9 million, 2 year Demand Side Management(DSM) program in 2008. Regrettably, HRM has not been able to participate in this process due to a stipulation that the utility, as temporary Administrator, included in their Commercial and Industrial Custom Program application form(see attached). Clause 15.0 (i) states:

> " Not withstanding the above, the Administrator holds sole rights to any electrical system capacity credits and environmental credits that may be associated with Measures for which incentives were received, and the Administrator can dispose of these credits in any manner authorized by law or regulation"

HRM has discussed this issue with NSPI in relation to two DSM projects which qualify for funding through the Commercial and Industrial Custom Program initiative. However, because of the clause, which would relinquish any rights to potential environmental credits, no funding has been applied for. This amounts to approximately $400,000.00 of DSM program funds, that would enable these projects to be developed, projects that could result in the reduction of more than 200 kW in demand savings, 2000 gWh of energy reduction and 2500 tonnes of greenhouse gas emissions annually. HRM is able to commence these projects as soon as funding is secured.

HRM has discussed its concern about the inclusion of the credits ownership clause directly with Nova Scotia Power, through meetings with its Vice President of Customer Service, and again with it's Manager of Conservation and Energy Efficiency. In both instances, NSPI was not receptive to setting the clause aside, or temporarily suspending the clause, pending resolution through stakeholder discussion or regulatory review, or to even consider some proration of potential credits based on the funding percentages. HRM also raised the issue with the DSM Project Development Working Group, through a presentation in September, 2008. Again, NSPI argued against any modification to the clause, or even a temporary removal of the clause to enable projects to move forward. As a result, the Municipality has concluded that a collaborative approach to resolving this issue is not an option, and is requesting that the Nova Scotia Utilities and Review Board. suspend this DSM Program requirement until such time as this issue can be dealt with by the permanent DSM Administrator, or through an open regulatory hearing, at which time all stakeholders will have an opportunity to present arguments around inclusion of environmental credits in DSM project evaluations.

Page Two

The Halifax Regional Municipality, through its Energy and Underground Services Advisory Committee, feels strongly that it is necessary to resolve this issue at the earliest possible time. The inclusion of Clause 15(i) is not indicative of the collaborative process which resulted in a Settlement Agreement, enabling Demand Side Management programs to be fast tracked for 2008. Transparency was key to that agreement, and this clause does not reflect that priority. HRM is a strong supporter of the Utility and Review Board sanctioned DSM program that NSPI is presently administering. It is frustrated by the fact that it cannot participate due to a stipulation that was unilaterally added after a collaborative process had fully vetted the proposed DSM program for 2008 and 2009 and which was subsequently supported by a stakeholder group which represented virtually all aspects of the rate paying public. This stipulation was not only not discussed during the DSM Collaborative, it had not been identified as a factor in DSM program evaluation included with the 2007 Integrated Resource Plan process, or the 2008 NSPI Rate Application. Suspension of the clause will enable both sides to properly prepare for a comprehensive discussion on the issue while allowing projects to move forward with the application process and implementation.

It is disappointing that this issue could not be resolved without involving the NSUARB. However, HRM feels that its projects will provide significant economic benefit to the municipality, they will contribute to provincial and municipal commitments to reduce greenhouse gas emissions, and they will assist NSPI with it's long range planning goal of deferring the need for additional generation additions for the foreseeable future. As a result, it is essential that these initiatives be able to proceed. The Halifax Regional Municipality would like to thank the Board for the opportunity to express its concerns in this matter, and looks forward to discussing this issue in more detail with all stakeholders in the Demand Side Management process.

Yours truly,

Dan English,
Chief Administrative Officer

Copy: Andrew Younger, Chair, EUGS Advisory Committee, HRM
Wayne Anstey, Deputy CAO of Operations
Rene Gallant, NSPI
Bruce Outhouse, QC, Board Counsel
Formal Interveners, NSPI P-884

CHIEF ADMINISTRATIVE OFFICE
Dan English, Chief Administrative Officer
P.O. Box 1749, Halifax, N.S. B3J 3A5
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NOVA SCOTIA POWER An Emera Company

STANDARD PROJECT DEVELOPMENT AGREEMENT TERMS AND CONDITIONS

Project Development Agreement ("Agreement") BETWEEN NOVA SCOTIA POWER INC. ("the Administrator") and [NAME] ("the Customer"), made the ______ day of ____________, 2_______, in __________________, Nova Scotia. Administrator and Customer may be individually referred to as a "Party" and collectively as the "Parties."

Figure 1: Customer and Project Information

Customer	Project
Customer Name	Project Name
Customer Mailing Address	Administrator Project Number
Customer Contact Name	Project Start Date
Customer Contact Title	Project Completion Date
Customer Phone:	Project Site (if different from mailing address)
Customer Email:	
Customer Facsimile:	

Figure 2: Incentive Payee Information (if not Customer)

Company Name	
Company Address	Contact Name
	Phone

Figure 3: Measures Included in Project

Facility Name	Measure Description	Peak Electrical Demand Savings (kW or kVA)	Electrical Energy Savings (kWh per year)	ANNEX A Reference
		Total Projected Annual Electrical Energy Savings		

Figure 4: Incentive Payment Schedule

Project Milestone	Maximum Incentive Amount Payable (CAD)
Feasibility Study Incentive – balance payment due now	$
Implementation Incentive at Milestone 1	$
Implementation Incentive at Milestone 2	$
Upon Administrator acceptance of Project completion	$
Maximum Total Incentive	$

Figure 5: Documents Incorporated By Reference

Name	Date
ANNEX A: Feasibility Study Report	
ANNEX A:	
ANNEX A:	

WHEREAS the Customer has applied for financial assistance from the Administrator, in the form of incentives through the Commercial and Industrial Custom Program ("Program") for the Project as set out herein.

1.0 **DEFINITIONS:**

"Business Day" shall mean a day other than a Saturday or Sunday on which the banks are open for business in the Province of Nova Scotia;

"Electric Energy Conservation Measures" shall mean the procurement, installation, commissioning and operation of new, unused equipment that is intended to reduce electrical energy consumption and electrical demand at Project Site;

"HST" shall mean the harmonized sales tax eligible pursuant to the Excise Tax Act (Canada);

"Maximum Total Incentive" shall mean the amount specified as "Maximum Total Incentive" in Figure 4 as may be adjusted in accordance with Section 6.4;

"Measures" shall mean the measures as specified in Figure 3 herein;

"Payee" shall mean the payee designated by the Customer in Figure 2 herein;

"Project" shall mean the project as specified in Figure 1 herein;

"Project Completion Date" shall mean the date specified as "Project Completion Date" in Figure 1 herein;

"Program Implementation Incentive Claim Form" shall mean the an application form, provided by Administrator and completed by Customer, that states Project status and defines the Project costs for which payment of an Implementation Incentive is being requested.

"Project Milestone" shall mean a the completion of a specific Project activity, such as implementation of a Measure or Measures, Project commissioning, and others as defined by this Agreement or by the documents incorporated by reference;

"Project Site" shall mean shall mean the Project Site as specified in Figure 1 herein;

"Project Start Date" shall mean the date specified as "Project Start Date" in Figure 1 herein.

2.0 **DOCUMENTS INCORPORATED BY REFERENCE:** The documents listed in Figure 5 are hereby incorporated by reference and made part of this Agreement as ANNEX A.

3.0 **ELIGIBILITY:** Program funding is limited and will be allocated by the Administrator in a manner that best serves the interests of the Program. Funds will be reserved for an approved Project, as described herein, only upon execution of this Agreement by both Parties. Proposed Projects must meet the following requirements to be eligible for approval and payment of Program Incentives ("Incentives"): (1) The Project Site must be a commercial or industrial facility now or to be located within the Administrator's service territory. (2) Projects must be for Electrical Energy Conservation Measures. (3) Electrical energy and demand savings from Project can not exceed the actual usage provided by the electric utility directly or indirectly serving the Project Site. Non-utility supply, such as cogeneration, self-generation or deliveries from another commodity supplier, does not qualify as usage from the utility. (4) Projects must meet all other Program requirements, terms and conditions contained herein.

4.0 **SUBMITTAL REQUIREMENTS FOR INCENTIVE PAYMENT APPROVAL:** The Customer must submit the documents described below in order to be eligible for incentive payments. Required documents include: (1) Complete engineering calculations to demonstrate energy and demand savings and documentation, if applicable; (2) Schematic drawings and/or manufacturer specification sheets ("cut sheets"), if applicable; (3) Any other documents related to the Project, Project Site, Measures, energy savings or other information deemed necessary by the Administrator to adequately review the payment request.

5.0 **INSPECTIONS:** The Customer must provide the Administrator with reasonable access to the Project and Project Site for all inspections, including: (1) Pre-installation inspection to verify the existing/baseline equipment; (2) Post-installation equipment inspection and (3) Inspection for any other reason that the Administrator deems necessary.

6.0 **PAYMENTS:** The Maximum Total Incentive is defined in Figure 4 and will be paid to the Payee in accordance with the schedule listed in Figure 4, pursuant to the terms and conditions of this Agreement:

6.1 Upon completion of Project or a Project Milestone, the Customer must request payment of Implementation Incentive by submitting the Program Implementation Incentive Claim form provided by the Administrator. Request for final incentive payment must include project measurement and verification results pursuant to ANNEX A.

6.2 After all required documents have been approved, and the appropriate inspection(s) have been completed, the Administrator will approve the applicable Incentive Payment. Incentive payments will be paid by cheque issued to Payee, within 45 days of approval.

6.3 The Administrator retains sole discretion to determine the appropriate baseline values and energy savings calculations used to determine incentive payments. The Administrator reserves the right to modify or cancel the incentive amount if the actual Project installed differs from the installation described in Figure 3 and ANNEX A, or if the installation was not consistent with generally accepted engineering practices.

6.4 The Administrator reserves the right to modify payment of the incentive amount if the actual Project annual electrical energy savings as determined using the measurement, verification and analysis methodologies pursuant to ANNEX A (the "Actual Annual Electrical Energy Savings"), are less than 85% of the Total Projected Annual Electrical Energy Savings defined in Figure 3. In such event, the Maximum Total Incentive for Project shall be adjusted by prorating as follows:

Adjusted Maximum Total Incentive Paid ($) =

$$\text{Maximum Total Incentive (\$, Figure 4)} \times \frac{\text{Actual Annual Electrical Energy Savings (kWh per year)}}{\text{Total Projected Annual Electrical Energy Savings (kWh per year)}}$$

The Administrator may require the Customer to return any incentive payments that the Administrator, at its sole discretion and based on the Adjusted Maximum Total Incentive, determines constitute overpayments for actual savings achieved by the project.

6.5 The Customer may authorize payment of the incentives to a third party Payee, as defined in Figure 2. Such authorization is at the Customer's sole discretion and the Customer may revoke or modify the authorization at any time by providing advance written notification to the Administrator. The Administrator shall not be responsible for any amounts paid to a Payee prior to the receipt by the Administrator of such notice. Should a dispute arise regarding the authorization, the most recently dated written communication or authorization shall govern.

6.6 If Customer fails to advise the Administrator that Project is complete, or fails to provide required post-installation documentation as described elsewhere in these terms and conditions, within 60 days of Project Completion Date, Payee may be denied incentive payment.

7.0 **PAYMENT DISQUALIFICATION:** Any incentives to be repaid to the Administrator, in whole or in part, shall be paid as follows:

7.1 If (1) the Project does not provide the Administrator with the related benefits specified in the Application for a period of three (3) years from the Project Completion Date, or (2) the energy benefit to the Administrator ceases in any way, including but not limited to the Customer and/or the Project Site ceases to receive electricity service directly or indirectly from Nova Scotia Power Inc., the measure, equipment and/or Project ceases to function, or the Customer ceases the use of the equipment, Measure or Project Site, the Customer shall refund to the Administrator any prorated amount of the incentive that the Administrator determines must be repaid, in its sole discretion, based on the actual period of time for which the Customer provided the energy benefit.

7.2 The Customer shall repay any amounts due to the Administrator within ninety (90) calendar days of receipt of notification from the Administrator. The Administrator shall be entitled to set off against payments owed to the Customer any amount due to the Administrator that remains unpaid one hundred and twenty (120) calendar days after the demand for payment.

8.0 **PERMITS AND LICENSES:** The Customer, at its own expense, shall obtain and maintain, or direct its contractors to obtain and maintain licenses and permits required by any relevant governing or regulatory bodies to perform its work. A failure to maintain necessary licenses and permits constitutes a material breach of the Customer's obligations under this Agreement.

9.0 **REMOVAL OF EQUIPMENT:** The Customer agrees, as a condition of participation in the Program, to remove, disable and dispose of the equipment being replaced by the Measures in accordance with all laws, rules, and regulations. The Customer agrees not to reinstall any of this equipment anywhere in the Province of Nova Scotia, or transfer it to any other party for installation in the Province of Nova Scotia.

10.0 **REVIEW AND DISCLAIMER:** THE ADMINISTRATOR'S AND/OR ITS CONSULTANTS' REVIEW OF THE DESIGN, CONSTRUCTION, OPERATION OR MAINTENANCE OF THE PROJECT OR ENERGY EFFICIENCY MEASURES SHALL NOT CONSTITUTE ANY REPRESENTATION AS TO THE ECONOMIC OR TECHNICAL FEASIBILITY, OPERATIONAL CAPABILITY, OR RELIABILITY OF THE PROJECT OR MEASURES, NOR SHALL THE CUSTOMER, IN ANY WAY, MAKE SUCH A REPRESENTATION TO A THIRD PARTY. THE CUSTOMER IS SOLELY RESPONSIBLE FOR THE ECONOMIC AND TECHNICAL FEASIBILITY, CONSTRUCTION, OPERATIONAL CAPABILITY AND RELIABILITY OF THE CUSTOMER'S PROJECT AND MEASURES. THE ADMINISTRATOR MAKES NO WARRANTY, WHETHER STATUTORY, EXPRESS OR IMPLIED, INCLUDING, WITHOUT LIMITATION, THE IMPLIED WARRANTIES OF MERCHANTABILITY AND FITNESS FOR ANY PARTICULAR PURPOSE, USE OR APPLICATION.

11.0 **TERM OF AGREEMENT:** The term of this Agreement shall commence on the last date that a Party executes this Agreement and shall run for a period of three (3) years unless earlier terminated pursuant to the terms of this Agreement. Notwithstanding the forgoing the Parties may mutually agree in writing to extend the term of Agreement.

12.0 **ASSIGNMENT:** The Customer consents to the Administrator's assignment of all of the Administrator's rights, duties and obligations under this Agreement. Such assignment shall relieve the Administrator of all rights, duties and obligations arising under this Agreement. Other than the Administrator's assignment, neither Party shall assign its rights or delegate its duties without the prior written consent of the other Party, except in connection with the sale or merger of a substantial portion of its properties. Any such assignment or delegation without written consent shall be null and void. Consent to assignment shall not be unreasonably withheld. If an assignment is requested by Customer, Customer is obligated to provide additional information if requested by the Administrator.

13.0 **ADVERTISING, MARKETING AND USE OF PARTY NAMES:** The Customer shall not use the Administrator's corporate name, trademark, trade name, logo, identity or any affiliation for any reason without the Administrator's prior written consent. The Customer shall make no representations to its customers on behalf of the Administrator. The Administrator may wish to publicize information relating to the Customer's participation in the program, including such data as: projected project energy savings, the incentive amount, and other information that does not compromise reasonable Customer expectations of confidentiality of proprietary or competitive information. In such instances, the Administrator will obtain Customer permission to make such information public.

14.0 **TAXES:** Incentives received by the Payee may be taxable by the federal, provincial, and local government. The Payee is responsible for declaring all incentives and paying all such taxes. The Administrator will not be responsible for any tax liability imposed on Payee or Customer as a result of any incentive given pursuant to this Agreement. Payee may not request incentive payment toward any tax amounts for which the Customer is or will be exempt from payment or is eligible for a refund.

15.0 **ELECTRIC SYSTEM CAPACITY CREDITS AND ENVIRONMENTAL CREDITS:** Measures purchased and installed in part through incentives provided by the Program are the property of the Customer, subject to any limitations contained within these Terms and Conditions.

(i) Not withstanding the above, the Administrator holds sole rights to any electric system capacity credits and environmental credits that may be associated with Measures for which Incentives were received, and the Administrator can dispose of these credits in any manner authorized by law or regulation.
(ii) In no event shall activity associated with any energy or environmental credits noted in Section 16.0(i) result in interference with the Customer's sole discretion to operate Measures as described in ANNEX A.

16.0 **INDEMNIFICATION:** The Customer shall indemnify, defend and hold harmless, and release the Administrator, its affiliates, subsidiaries, parent companies, officers, directors, agents and employees, from and against all claims, demands, losses, damages, costs, expenses, and liability (legal, contractual, or otherwise), which arise from or are in any way connected with any:

(i) injury to or death of persons, including but not limited to employees of the Administrator or the Customer;
(ii) injury to property or other interests of the Administrator, Customer, or any third party;
(iii) violation of local, provincial, or federal common law, statute, or regulation, including but not limited to environmental laws or regulations; or
(iv) strict liability imposed by any law or regulation; so long as such injury, violation, or strict liability (as set forth in (i) - (iii) above) arises from or is in any way connected with the Customer's performance of, or failure to perform, this Agreement, however caused, regardless of any strict liability or negligence of the Administrator whether active or passive, excepting only such loss, damage, cost, expense, liability, strict liability, or violation of law or regulation that is caused by the sole negligence or wilful misconduct of the Administrator, its officers, managers or employees.

17.0 The Customer acknowledges that any claims, demands, losses, damages, costs, expenses, and legal liability that arise out of, result from, or are in any way connected with the release or spill of any legally designated hazardous material or waste as a result of the work performed under this Agreement are expressly within the scope of this indemnity, and that the costs, expenses, and legal liability for environmental investigations, monitoring, containment, abatement, removal, repair, cleanup, restoration, remedial work, penalties, and fines arising from strict liability, or violation of any local, state, or federal law or regulation, attorney's fees, disbursements, and other response costs incurred as a result of such releases or spills are expressly within the scope of this indemnity.

18.0 The Customer shall, on the Administrator's request, defend any action, claim or suit asserting a claim that may be covered by this indemnity. The Customer shall pay all costs and expenses that may be incurred by the Administrator in enforcing this indemnity, including reasonable attorney's fees. This indemnity shall survive the termination of this Agreement for any reason.

19.0 If this Agreement is assigned pursuant to Section 13.0, the Customer agrees that this indemnification shall continue to apply to the Administrator and shall apply to the assignee.

20.0 **TERMINATION OF AGREEMENT:** If the Customer has either: (a) not engaged in installation of the approved project, (b) not applied for and been granted a Project extension in writing by NSPI prior to the Project Start Date, or (c) breached any of its obligations pursuant to this Agreement including but not limited to its obligations under Section 9, the Administrator may terminate this Agreement without notice and without any liability whatsoever to the Customer. The Administrator may cease incentive payments, require the return of incentive payments, and/or terminate this Agreement if the Project is not installed and fully operational ,and the Customer has not received, as appropriate, final drawings, operation and maintenance manuals, and operator training by Project Completion Date.

21.0 **LIMITATION OF LIABILITY:** The Administrator shall not be liable for any special, incidental, indirect, or consequential damages, including without limitation, loss of profits or commitments to subcontractors, and any special, incidental, indirect or consequential damages incurred by the Customer.

22.0 **WRITTEN NOTICE:** Any written notice, demand or request required or authorized in connection with this Agreement shall be deemed properly given if delivered in person or sent by facsimile, nationally recognized overnight courier, or first class mail, postage prepaid, to the address specified below, or to another address specified in writing by the Administrator.

NOVA SCOTIA POWER An Emera Company

ADMINISTRATOR

Nova Scotia Power Inc.
PO Box 910
Halifax, Nova Scotia Canada B3J 2W5
Attention: Corporate Secretary
Fax: (902) 428-6171

WITH A COPY TO:
Nova Scotia Power Inc.
P.O. Box 910
Halifax, Nova Scotia Canada B3J 2W5

Attention: Manager, Conservation and Efficiency
Fax: (902) 428-6102

CUSTOMER

As defined in Figure 1.

Notices shall be deemed received (a) if personally or hand-delivered, upon the date of delivery to the address of the person to receive such notice if delivered before 4:30 p.m., or otherwise on the Business Day following personal delivery; (b) if mailed, three Business Days after the date the notice is postmarked; (c) if by facsimile, upon electronic confirmation of transmission, followed by telephone notification of transmission by the noticing Party; or (d) if by overnight courier, on the Business Day following delivery to the overnight courier within the time limits set by that courier for next-day delivery.

23.0 **CONFLICTS BETWEEN TERMS:** Should a conflict exist between the main body of this Agreement and the documents incorporated by reference, the main body of this Agreement shall control. Should a conflict exist in the documents incorporated by reference, the documents shall control in the order listed in Figure 5. Should a conflict exist between an applicable federal, provincial, or local law, rule, regulation, order or code and this Agreement, the law, rule, regulation, order or code shall control. Varying degrees of stringency among the main body of this Agreement, the documents incorporated by reference, and laws, rules, regulations, orders, or codes are not deemed conflicts, and the most stringent requirement shall control. Each Party shall notify the other immediately upon the identification of any conflict or inconsistency concerning this Agreement.

24.0 **MISCELLANEOUS:** This Agreement shall at all times be subject to such changes or modifications by the Nova Scotia Utility and Review Board as it may from time to time direct in the exercise of its jurisdiction. This Agreement shall be governed and construed in accordance with the laws of the Province of Nova Scotia, without regard to its conflict of laws provisions. If any provision of this Agreement shall be held by a court of competent jurisdiction to be illegal, invalid or unenforceable, the remaining provisions shall remain in full force and effect. This Agreement constitutes the entire agreement and understanding between the Parties as to the subject matter of this Agreement (other than any Agreement for Project financing, if applicable) and supersedes all prior agreements, representations, writings and discussions between the Parties, whether oral or written, with respect to the subject matter hereof. No amendment, modification or change to this Agreement shall be binding or effective unless expressly set forth in writing and signed by the Administrator's representative authorized to execute the Agreement.

25.0 **PROJECT FINANCING:** Terms and conditions for Project financing, if applicable, are detailed under a separate agreement between Customer and Administrator.

26.0 **SURVIVAL AND ENUREMENT:** All provisions of this Agreement which by their express terms or nature are continuing shall survive expiration or termination of this Agreement, including this provision, the provisions of Sections 7 and 15 and any provisions relating to indemnification, termination, as well as any provisions which are required to determine, or which exclude or limit, any liability or which are otherwise required to give effect to or interpret any such provisions which are continuing.

27.0 **FURTHER ASSURNACES:** The Customer will, from time to time, do, execute and deliver or shall cause to be done, executed and delivered all such further acts, documents or other instruments as may reasonably be requested by the Administrator in order to cure any defects in the execution and delivery of or to comply with or accomplish the covenants and agreements contained in this Agreement.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their duly authorized representatives as of the first date set forth above.

Customer:	**Administrator:**
Signature	Signature
Name (print)	Name (print)
Date (yyyy/mm/dd)	Date (yyyy/mm/dd)

Nova Scotia Utility and Review Board

Mailing address
PO Box 1692, Unit "M"
Halifax, Nova Scotia
B3J 3S3
uarb.board@gov.ns.ca
Web www.nsuarb.ca

Office
3rd Floor
1601 Lower Water Street
Halifax, Nova Scotia B3J 3P6
902 424-4448 t
902 424-3919 f

February 2, 2009

By Email: englisd@halifax.ca

Mr. Dan English
Chief Administrative Officer
Halifax Regional Municipality
PO Box 1749
Halifax NS B3J 3A5

Dear Mr. English:

Demand Side Management Program Application - P-884

Receipt is acknowledged of your letter dated January 30, 2009 and received February 2, 2009, outlining Halifax Regional Municipality's concerns regarding their inability to participate in NSPI's 2 year Demand Side Management program.

Your letter has been directed to the Board.

Yours very truly,

Nancy McNeil

Nancy McNeil
Regulatory Affairs Officer/Clerk

c	Andrew Younger, Chair, EUGS Advisory Committee, HRM	By Email
	Wayne Anstey, Deputy CAO of Operations	By Email
	Rene Gallant, NSPI	By Email
	S. Bruce Outhouse, Q.C., Board Counsel	By Email
	Formal Intervenors, NSPI P-884	By Email

BLOIS, NICKERSON & BRYSON

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Since 1864

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S. Bruce Outhouse, Q.C.
S. Bruce Outhouse Law Inc.
Telephone: 902-425-6000
Fax: 902-429-7347
bouthouse@bloisnickerson.com
www.bloisnickerson.com

February 13, 2009

VIA FAX (490-4044)
Mr. Dan English,
Chief Administrative Officer,
HALIFAX REGIONAL MUNICIPALITY,
P.O. Box 1749,
Halifax, NS B3J 3A5

Dear Mr. English:

**Re: Demand Side Management Program Application –
Your letter to the Board dated January 30, 2009**

I am counsel to the Nova Scotia Utility and Review Board.

After considering your letter of January 30, 2009, the Board asked me to confer with the parties and make arrangements to have the carbon credits issue dealt with as expeditiously as possible. I have conferred with counsel for HRM and NSPI in connection with this matter. As a result of those consultations, it was agreed that this issue be included in the list of issues to be dealt with in the upcoming DSM hearing. While the dates for the DSM hearing have not been officially set as yet, it is anticipated that the hearing will be held in early June.

Yours truly,

S. Bruce Outhouse

SBO:sw
fc: Ms. Nancy McNeil (424-3919)
fc: Ms. Mary Ellen Donovan (490-4232)
fc: Mr. Martin Ward, Q.C. (490-4232)
fc: Mr. Rene Gallant (428-6542)

Appendix E

DSM Cost Recovery Rider

NOVA SCOTIA POWER INCORPORATED

DEMAND SIDE MANAGEMENT COST RECOVERY RIDER

APPLICABILITY:

This schedule applies to all electric rate classes with the exception of the Wholesale Market Non-Dispatchable Supplier Spill Tariff and the Mersey System Tariff (i.e., Mersey Basic Block).

RESPONSIBILITIES OF INDEPENDENT DSM ADMINISTRATOR

It shall be the responsibility of the independent Demand Side Management Administrator (Administrator) to apply to the Nova Scotia Utility and Review Board (UARB) to seek approval of all demand side management and energy efficiency programs and to itemize and seek approval for all related costs.

On or before June 1 of the year preceding the implementation of the approved programs and program costs, the Administrator shall advise Nova Scotia Power Inc. of:

a. the program amount approved by the UARB to be recovered by this Rider,
b. the energy savings (reduction in kWh sales by program) anticipated by the approved programs,
c. the costs incurred and energy savings achieved by the prior year's programs.

RESPONSIBILITIES OF NOVA SCOTIA POWER INC.

On or before October 1 in the year preceding the implementation of the approved programs, Nova Scotia Power Inc. shall apply to the UARB to seek approval of the Demand Side Management (DSM) Cost Recovery Rider amounts. NSPI shall pay to the Administrator the amount approved by the UARB to fund the program costs, on a monthly basis as recovered by this Rider.

DEMAND SIDE MANAGEMENT COST RECOVERY:

The monthly amount computed under each of the rate schedules to which this DSM Cost Recovery Rider (DCRR) is applicable shall be increased or decreased by the DCRR at a class-specific rate per kilowatt hour of monthly consumption in accordance with the following formula:

DCRR = PCR + LCFC + BA

Where:

PCR = PROGRAM COST RECOVERY

The PCR includes all estimated costs for each upcoming twelve month period for demand side management and energy efficiency programs that have been requested by the Administrator and approved by the Board ("approved programs"). Such program costs shall include the cost of planning, developing, implementing, monitoring, and evaluating DSM programs, including but not limited to costs for consultants, employees and administrative expenses. For the

NOVA SCOTIA POWER INCORPORATED

DEMAND SIDE MANAGEMENT COST RECOVERY RIDER

calendar years 2010, 2011 and 2012, the PCR shall be computed for each rate schedule using the cost allocation methodology set out in Attachment 1 to this tariff. The cost allocation approach may be modified for use after 2012 as approved by the UARB.

LCFC = LOST CONTRIBUTION TO FIXED COSTS

The LCFC component does not apply to the following rate classes: Generation Replacement and Load Following Tariff, Extra High Voltage Time-of-Use Real Time Pricing Tariff, High Voltage Time-of-Use Real Time Pricing Tariff, Distribution Voltage Time-of-Use Real Time Pricing Tariff, Wholesale Market Backup/Top-up Service Tariff, and the Mersey System Tariff.

The fixed cost contribution associated with lost sales due to DSM programs implemented on and after the effective date of this tariff will be recovered as follows:

For each upcoming twelve month period, the estimated reduction in lost kWh sales in each applicable customer class and associated with anticipated program measures, shall be multiplied by the unit fixed costs associated with these lost kWh sales and for each applicable rate class. The unit fixed costs will be derived from the Cost of Service Study approved in the last general rate case. The estimated amount of foregone fixed costs for each applicable customer class for the upcoming twelve month period will be recovered through the class-specific LCFC component. Recovery of the foregone fixed cost contribution due to lost sales calculated for a twelve month period shall be included in the LCFC components in the subsequent year(s) until implementation of new rates pursuant to a general rate case at which time the LCFC components will be reset to zero.

LCFC amounts for each applicable rate class will be calculated based on estimates of energy savings associated with anticipated program measures, and estimated sales for the upcoming twelve month period. At the end of each such period, any difference between the billed and actual amounts shall be reconciled in future billings under the Balance Adjustment (BA) component.

BA = BALANCE ADJUSTMENT

The BA will be calculated for each rate class separately on a calendar year basis and is used to reconcile the difference between the amount of revenues actually billed through the PCR, LCFC and previous application of the BA and the revenues which should have been billed, as follows:

(1) For the PCR, the balance adjustment amount will be the difference between the amount billed in a twelve month period from the application of the PCR unit charges and the actual cost of the approved programs during the same twelve month period.

NOVA SCOTIA POWER INCORPORATED

DEMAND SIDE MANAGEMENT COST RECOVERY RIDER

(2) For the LCFC component, the balance adjustment amount would be the difference between the amount billed during the twelve month period through the application of the LCFC unit charge and the amount of the foregone recovery of fixed costs due to lost sales resulting from actual DSM measures implemented during the twelve month period.

(3) For the BA, the balance adjustment amount will be the difference between the amount billed in a twelve month period from application of the BA and the balance adjustment amount established for the same twelve month period.

Each change in the DCRR shall be placed into effect with bills rendered on and after the effective date of such change.

Attachment 1
DSM Cost Allocation Approach

There are 3 kinds of cost benefits resulting from DSM:

1. *System* - Avoided future infrastructure and related costs, reduced fuel costs, and contribution to achieving environmental and emissions restrictions. All customers receive these benefits.

2. *Class* - When customers within a class participate, the whole class benefits by a reduction in their cost of service allocation, even those who do not actively participate.

3. *Participation* - Customers who are able to participate in DSM programs can lower their own electricity usage and therefore their costs.

The recovery of DSM costs from customers should reflect the level of benefit received by customer classes. Those customer classes who receive the most benefit (i.e., in all three categories) would bear the most responsibility to contribute to the costs. A customer class that receives only system benefits would contribute to the costs accordingly despite not directly participating in programs. Given the nature of DSM programs and benefits it is not possible to precisely calculate and allocate costs based upon these various benefits.

Proposed Allocation of DSM Program Costs:

System benefits will be allocated to all customer classes, except for the Mersey System Rate (i.e., Basic Block), in accordance with the COSS methodology reflecting allocation of generation rate base as per the most recent rate case decision.

Once system benefits have been allocated, the remaining costs relate to the class and participant benefits. These costs will be assigned to the class(es) participating in the DSM programs in proportion to amounts invested in each class.

Method:

- Step 1 – Allocate the system benefits to all customer classes, except to the Mersey System Rate (i.e., Basic Block), allocating s x DT, in accordance with the COSS methodology per the most recent rate case decision, where “DT” represents the total approved DSM program costs and “s” represents the percentage of those costs that the parties agree to be system benefits. “S” will be equal to 25%.

- Step 2 – Directly assign to each class 75% (=1-s) of the DSM investment made for customers in that class. In the column 1 of the attached table for example, DSM expenditures for customers in the residential class could be labelled DC_{res}. The cost allocation approach showing allocation of system costs and proportionate participation costs by class for 2010 are shown on the attached table. If Bowater Mersey participates in DSM Programs, Step 2 will apply to the ELI -2P-RTP class (unless Bowater’s resultant demand drops below 42 MW in which case, it will apply to the Additional Energy served under the Mersey Agreement, to the extent below 42 MW).

- Step 3 – Add the amounts from Step 1 and Step 2 to obtain the total amount to be recovered from each class.

- Step 4 - Divide the total amount to be recovered from each class by the anticipated electricity sales for the class to derive the cost recovery surcharge for each class for the year.

- Step 5 – Annually, true up the forecasted participation by customer class based upon actual experience so that class and participation benefits are more accurately allocated to participating classes.

- Illustrative Cost Allocation Calculations for 2010: (see attached table for steps 1-3)

  DT = $22.89 million
  s = 25%
  DC for each separate class is set out in column 1 of the attached table.

  Step 1 – Allocate 25% x $22.89 million = $5.7225 million to all customer classes except the Mersey System Rate

  Step 2 – Directly assign to each class 75% (=1-s) of the DC for each class

  Step 3 – Add the amounts for Step1 and Step 2 to obtain the total amount to be recovered from each class.

Conditions:

- The allocation of costs based on "benefits" in this approach does not create a precedent for future cost allocation methodologies.

- This approach applies to classes as a whole (not to individual customers). As a contract rate predicated on power production specifically from the Mersey Hydro System, the Mersey System Rate (i.e., Basic Block) is not affected by DSM energy savings. This proviso does not affect the interpretation of the Mersey Agreement as it relates to the Basic Block, Additional Energy or any other matter.

- This approach applies to total approved DSM program costs. As such, the attached table is illustrative, and final calculations will depend upon the final approved DSM programs and total program costs.

- This approach will be reviewed after three years (i.e., it applies to 2010, 2011 and 2012).

Illustration of Program Costs allocated to rate classes

Line #									
1									
2									
3	**COLUMN**	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**
4									
5	**FORMULA**							**C + E**	
6									
7		**Total Expenditure by Rate class before allocation. (DC)** [1]		**System Benefit Costs (25% of the total)**		**Participating Class benefit Costs (75% of the total)**		**Total Allocated Costs**	
8		**$ Amount**	**Relative Share**	**$ Amount**	**Relative Share**	**$ Amount**	**Relative Share**	**$ Amount**	**Relative Share**
9	**Rate Class**								
10	Residential	$7,722,093	33.7%	$2,330,369	40.7%	$5,791,570	33.7%	$8,121,938	35.5%
11	Small General	$1,566,313	6.8%	$137,212	2.4%	$1,174,735	6.8%	$1,311,947	5.7%
12	General Demand	$7,258,663	31.7%	$1,198,002	20.9%	$5,443,997	31.7%	$6,641,999	29.0%
13	Large General	$2,432,479	10.6%	$187,445	3.3%	$1,824,359	10.6%	$2,011,804	8.8%
14	Small Industrial	$272,956	1.2%	$112,524	2.0%	$204,717	1.2%	$317,241	1.4%
15	Medium Industrial	$1,334,208	5.8%	$257,143	4.5%	$1,000,656	5.8%	$1,257,799	5.5%
16	Large Industrial	$1,098,582	4.8%	$408,879	7.1%	$823,936	4.8%	$1,232,815	5.4%
17	ELI 2P-RTP	$3	0.0%	$861,097	15.0%	$2	0.0%	$861,099	3.8%
18	Municipal	$720,723	3.1%	$95,488	1.7%	$540,542	3.1%	$636,030	2.8%
19	Unmetered	$483,978	2.1%	$63,590	1.1%	$362,983	2.1%	$426,573	1.9%
20	Bowater Mersey (AE only)	$1	0.0%	$67,519	1.2%	$1	0.0%	$67,520	0.3%
21	GRLF	$4	0.0%	$3,232	0.1%	$3	0.0%	$3,235	0.0%
22	Wholesale Market Backup/Top-up	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%
23	1P-RTP	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%
24	Total [2]	$22,890,003	100.0%	$5,722,500	100.0%	$17,167,502	100.0%	$22,890,002	100.0%
25									
26									
27									

28 (1) DC = DSM expenditure by class
29 (2) DT = DSM Program Total Cost
30

Appendix F

Rider Calculations

TABLE 1 Allocation of 25% of program costs deemed to be associated with system benefits (Source: COSS, Compliance Filing 2009)

COLUMN A B C D E F G H

Program Cost Recovery by Benefits

System Benefits	25.0%	$5,722,500
Combined Class and Participant Benefits	75.0%	$17,167,500
Total	100.0%	$22,890,000

Functionalization of System Benefit DSM Costs

	Factors
Generation	100%
Transmission	0%
Distribution	0%
Retail	0%

Classification of System Benefit DSM Costs

	Factors[1]
Demand-related	32.9%
Energy-related	67.1%
Total	100.0%

Line #		Demand-related Costs			Energy-related Costs			Total	
18	Rate Class	3 CP kW Demands [2]	Demand-related	$ Amount	MWh Energy Requirement [3]	Energy-related	$ Amount	Relative Share	Total Amount
19	Residential Total [5]	3,200,476	48.7%	$916,620	4,683,148	36.8%	$1,413,749	40.7%	$2,330,369
20	Small General	179,891	2.7%	$51,521	283,859	2.2%	$85,691	2.4%	$137,212
21	General Demand	1,290,681	19.6%	$369,652	2,743,968	21.6%	$828,349	20.9%	$1,198,002
22	Large General	177,953	2.7%	$50,966	452,098	3.6%	$136,479	3.3%	$187,445
23	Small Industrial	109,669	1.7%	$31,409	268,699	2.1%	$81,115	2.0%	$112,524
24	Medium Industrial	249,246	3.8%	$71,384	615,341	4.8%	$185,759	4.5%	$257,143
25	Large Industrial	369,028	5.6%	$105,690	1,004,336	7.9%	$303,189	7.1%	$408,879
26	ELI 2P-RTP	749,730	11.4%	$214,723	2,141,160	16.8%	$646,373	15.0%	$861,097
27	Municipal	113,817	1.7%	$32,597	208,330	1.6%	$62,891	1.7%	$95,488
28	Unmetered	86,672	1.3%	$24,823	128,418	1.0%	$38,767	1.1%	$63,590
29	Bowater Mersey (AE only) [4]	42,861	0.7%	$12,275	182,999	1.4%	$55,244	1.2%	$67,519
30	Gen. Repl./ Load Foll.	(650)	-0.01%	($186)	11,322	0.1%	$3,418	0.1%	$3,232
31	Wholesale Market Backup/Top-up	-	0.00%	$0	-	0.0%	$0	0.0%	$0
32	1P-RTP	-	0.0%	$0	-	0.0%	$0	0.0%	$0
33	Total	**6,569,374**	**100.0%**	**$1,881,476**	**12,723,678**	**100.0%**	**$3,841,024**	**100.0%**	**$5,722,500**
35	Classification Breakdown		**32.9%**			**67.1%**			**100.0%**

(1) The proposed classification is a weighted average of the fully classified total generation plant portion of the rate base as shown under the heading "Fully Classified Rate Base" on line 6 of schedule 2b of the COSS.
(2) Source: Exh 9c line (14) 3 Coincident Peak (3CP) demands COS
(3) Source: Exh 9a Annual column (3) Energy Requirement
(4) Statistics for the AE class are predicated on the share of AE class in the total Bowater Mersey figures shown in Exh 9c line (14) and Exh 9a. The Bowater Mersey total include AE and Mersey Basic Block.
(5) All residential rate classes will use the same unit fixed cost estimate.

TABLE 2 Allocation of 75% of DSM Program Costs deemed to be associated with benefits realized by participating classes.

Line #													
1													
2	**COLUMN**	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**L**
3													
4	**FORMULA**											**Σ col A to J**	**K x 75%**
5													
6		**Program costs incurred on participating rate classes.**											**Program Costs Directly Assigned to Participating rate classes (75% of the total)**
7	**Program**	Efficient Products	Existing Homes	New Homes	Low Income	Prescriptive Rebate	Custom	New Construction	Small Business DI Lighting	Education & Outreach	Development & Research	All Program Costs Combined	
8													
9	**Rate Class**												
10	Residential	$890,489	$2,078,508	$2,029,487	$2,137,334	$0	$0	$0	$0	$360,785	$225,491	$7,722,093	$5,791,570
11	Small General	$724,817	$0	$0	$0	$0	$0	$0	$809,634	$19,608	$12,255	$1,566,313	$1,174,735
12	General Demand	$414,181	$0	$0	$0	$46,100	$1,923,913	$540,908	$4,318,046	$9,548	$5,967	$7,258,663	$5,443,997
13	Large General	$0	$0	$0	$0	$44,660	$1,863,790	$524,005	$0	$15	$9	$2,432,479	$1,824,359
14	Small Industrial	$0	$0	$0	$0	$0	$0	$0	$269,878	$1,892	$1,183	$272,953	$204,715
15	Medium Industrial	$0	$0	$0	$0	$24,491	$1,022,079	$287,358	$0	$173	$108	$1,334,208	$1,000,656
16	Large Industrial	$0	$0	$0	$0	$20,169	$841,712	$236,647	$0	$33	$21	$1,098,582	$823,936
17	ELI 2P-RTP	$0	$0	$0	$0	$0	$0	$0	$0	$2	$1	$3	$2
18	Municipal	$41,418	$42,419	$41,418	$43,619	$6,003	$250,509	$70,431	$224,898	$5	$3	$720,723	$540,542
19	Unmetered	$0	$0	$0	$0	$8,644	$360,734	$101,420	$0	$8,111	$5,069	$483,978	$362,983
20	Bowater Mersey (AE only)	$0	$0	$0	$0	$0	$0	$0	$0	$1	$1	$1	$1
21	GRLF	$0	$0	$0	$0	$0	$0	$0	$0	$2	$2	$4	$3
22	Wholesale Market Backup/Top-up	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	1P-RTP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	**Total**	**$2,070,905**	**$2,120,927**	**$2,070,905**	**$2,180,953**	**$150,066**	**$6,262,736**	**$1,760,769**	**$5,622,456**	**$400,175**	**$250,109**	**$22,890,000**	**$17,167,500**
25													
26													

32 Notes:

33 1 Education & Outreach and Development & Research costs were allocated based on Customer counts used in the Cost of Service Studies submitted in 2009 Compliance Filing

TABLE 2 a) Estimate of DSM Program participation by rate class

Line #	COLUMN	A	B	C	D	E	F	G	H
1									
2	**COLUMN**	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**
3									
4		**Program costs incurred on participating rate classes.**							
5	**Program**	Efficient Products	Existing Homes	New Homes	Low Income	C & I Prescriptive Rebate	C & I Custom	C & I New Construction	Small Business DI Lighting
6									
7	**Rate Class**								
8	Residential	43.0%	98.0%	98.0%	98.0%	0.0%	0.0%	0.0%	0.0%
9	Small General	35.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	14.4%
10	General Demand	20.0%	0.0%	0.0%	0.0%	30.7%	30.7%	30.7%	76.8%
11	Large General	0.0%	0.0%	0.0%	0.0%	29.8%	29.8%	29.8%	0.0%
12	Small Industrial	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	4.8%
13	Medium Industrial	0.0%	0.0%	0.0%	0.0%	16.3%	16.3%	16.3%	0.0%
14	Large Industrial	0.0%	0.0%	0.0%	0.0%	13.4%	13.4%	13.4%	0.0%
15	ELI 2P-RTP	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
16	Municipal	2.0%	2.0%	2.0%	2.0%	4.0%	4.0%	4.0%	4.0%
17	Unmetered	0.0%	0.0%	0.0%	0.0%	5.8%	5.8%	5.8%	0.0%
18	Bowater Mersey (AE only)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
19	GRLF	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
20	Wholesale Market Backup/Top-up	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
21	1P-RTP	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
22	**Total**	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
23									

Notes:

1 The Efficient Products participation is based on the program manager's estimate of class participation in 2008

2 The C&I programs participation is estimated based on the Q1 2009 C&I custom project list of committed and potential projects

3 Small Business Direct Install Lighting participation is based on the program manager's estimate of class participation in 2008

TABLE 3 Illustration of Calculations of Unit Program Costs by class

Line #	COLUMN	A	B	C	D	E	F	G	H	I	J	K	L	M
5	FORMULA	Table 2 Column K		Table 1 Column H		Table 2 Column L		C + E					I - K	G / L x 100
7		Total Expenditure by Rate class		System Benefit Costs (25% of the total expenditure allocated to classes using COS methodology)		Participating Class benefit Costs (75% of the total expenditure directly assigned to participating classes)		Total Allocated Costs[1]		KWhs				PCR[3]
8		$ Amount	Relative Share	$ Amount	Relative Share	$ Amount	Relative Share	$ Amount	Relative Share	Sales Forecast without DSM Program[4]	Engineering Estimate of DSM-related energy reduction at the generator's gate[5]	Engineering Estimate of DSM-related energy reduction at the meter[6]	Sales Forecast with DSM Program	cents/kWh
9	**Rate Class**													
10	Residential Subtotal [2]	$7,722,093	33.7%	$2,330,369	40.7%	$5,791,570	33.7%	$8,121,938	35.5%	4,137,936,205	18,082,975	16,162,830	4,121,773,375	0.197
11	Small General	$1,566,313	6.8%	$137,212	2.4%	$1,174,735	6.8%	$1,311,947	5.7%	249,149,437	5,115,358	4,597,661	244,551,776	
12	General Demand	$7,258,663	31.7%	$1,198,002	20.9%	$5,443,997	31.7%	$6,641,999	29.0%	2,464,731,011	26,415,831	24,662,338	2,440,068,673	0.272
13	Large General	$2,432,479	10.6%	$187,445	3.3%	$1,824,359	10.6%	$2,011,804	8.8%	420,518,622	13,469,659	12,703,630	407,814,993	0.493
14	Small Industrial	$272,953	1.2%	$112,524	2.0%	$204,715	1.2%	$317,239	1.4%	252,424,057	671,202	630,592	251,793,465	0.126
15	Medium Industrial	$1,334,208	5.8%	$257,143	4.5%	$1,000,656	5.8%	$1,257,799	5.5%	535,135,300	7,386,587	6,964,536	528,170,764	0.238
16	Large Industrial	$1,098,582	4.8%	$408,879	7.1%	$823,936	4.8%	$1,232,815	5.4%	960,514,559	6,083,072	5,843,489	954,671,070	0.129
17	ELI 2P-RTP	$3	0.0%	$861,097	15.0%	$2	0.0%	$861,099	3.8%	2,001,034,000	-	-	2,001,034,000	0.043
18	Municipal	$720,723	3.1%	$95,488	1.7%	$540,542	3.1%	$636,030	2.8%	197,534,384	2,838,287	2,702,873	194,831,512	0.326
19	Unmetered	$483,978	2.1%	$63,590	1.1%	$362,983	2.1%	$426,573	1.9%	112,811,452	2,607,031	2,347,619	110,463,833	0.386
20	Bowater Mersey (AE only)	$1	0.0%	$67,519	1.2%	$1	0.0%	$67,520	0.3%	178,920,000	-	-	178,920,000	0.038
21	GRLF	$4	0.0%	$3,232	0.1%	$3	0.0%	$3,235	0.0%	10,597,940	-	-	10,597,940	0.031
22	Wholesale Market Backup/Top-up	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	-	-	-	-	-
23	1P-RTP	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	-	-	-	-	-
24	Total	$22,890,000	100.0%	$5,722,500	100.0%	$17,167,500	100.0%	$22,890,000	100.0%	11,521,306,968	82,670,000	76,615,568	11,444,691,400	0.200

(1) NSPI is proposing to recover these costs in 2010.
28 (2) All residential rate classes will use the same unit fixed cost estimate.
29 (3) PCR is an acronym for DSM Program Cost Recovery.
(4) Accrued Sales based on Billed Sales Forecast Without Conservation filed with the UARB on April 30, 2009.
(5) An estimate of committed energy savings proposed to be used for LCFC calculations for 2010.
30 (6) DSM Sales effect is estimated using class line losses from the Cost of Service Studies submitted in 2009 Compliance Filing.

TABLE 4 Illustrative Summary of PCR Calculations for Program Costs in years 2010-2014

Line #	COLUMN	A	B	C	D	E

Table 4.1 Forecast of Allocated DSM Program costs[1]

Line #	Rate Class	2010	2011	2012	2013	2014
8	Residential Subtotal	$8,121,938	$8,870,619	$10,644,743	$12,418,866	$14,192,990
9	Small General	$1,311,947	$1,432,883	$1,719,459	$2,006,036	$2,292,612
10	General Demand	$6,641,999	$7,254,259	$8,705,110	$10,155,962	$11,606,814
11	Large General	$2,011,804	$2,197,253	$2,636,703	$3,076,154	$3,515,604
12	Small Industrial	$317,239	$346,482	$415,779	$485,075	$554,371
13	Medium Industrial	$1,257,799	$1,373,744	$1,648,492	$1,923,241	$2,197,990
14	Large Industrial	$1,232,815	$1,346,456	$1,615,747	$1,885,039	$2,154,330
15	ELI 2P-RTP	$861,099	$940,475	$1,128,570	$1,316,665	$1,504,760
16	Municipal	$636,030	$694,659	$833,591	$972,523	$1,111,455
17	Unmetered	$426,573	$465,894	$559,073	$652,252	$745,431
18	Bowater Mersey (AE)	$67,520	$73,743	$88,492	$103,241	$117,989
19	Gen. Repl./ Load Foll.	$3,235	$3,533	$4,240	$4,946	$5,653
20	Wholesale Market Backup/Top-up	$0	$0	$0	$0	$0
21	1P-RTP	$0	$0	$0	$0	$0
22	Total	$22,890,000	$25,000,000	$30,000,000	$35,000,000	$40,000,000

Table 4.2 Forecast kWh sales reflecting DSM effect

Line #	Rate Class	2010	2011	2012	2013	2014
29	Residential non ETS	3,957,309,244	3,981,548,400	3,947,922,855	4,018,654,045	3,982,960,466
30	Residential ETS	164,464,131	165,471,500	164,074,036	167,013,595	165,530,185
31	Residential Subtotal	4,121,773,375	4,147,019,900	4,111,996,891	4,185,667,640	4,148,490,651
33	Small General	244,551,776	246,049,695	243,971,721	248,342,731	246,136,957
34	General Demand	2,440,068,673	2,455,014,486	2,434,281,045	2,477,893,750	2,455,885,164
35	Large General	407,814,993	410,312,925	406,847,691	414,136,796	410,458,444
36	Small Industrial	251,793,465	253,335,740	251,196,233	255,696,678	253,425,587
37	Medium Industrial	528,170,764	531,405,895	526,917,989	536,358,279	531,594,359
38	Large Industrial	954,671,070	960,518,584	952,406,674	969,470,041	960,859,234
39	ELI 2P-RTP	2,001,034,000	2,013,290,655	1,996,287,724	2,032,053,318	2,014,004,674
40	Municipal	194,831,512	196,024,886	194,369,389	197,851,721	196,094,407
41	Unmetered	110,463,833	111,140,442	110,201,822	112,176,204	111,179,858
42	Bowater Mersey (AE)	178,920,000	178,920,000	178,920,000	178,920,000	178,920,000
43	Gen. Repl./ Load Foll.	10,597,940	10,662,854	10,572,803	10,762,225	10,666,636
44	Wholesale Market Backup/Top-up	-	-	-	-	-
45	1P-RTP	-	-	-	-	-
46	Total	11,444,691,400	11,513,696,062	11,417,969,983	11,619,329,383	11,517,715,971

Table 4.3 Estimated PCR Components in cents per kWh

Line #	Rate Class	2010	2011	2012	2013	2014
53	Residential non ETS	0.19705	0.21390	0.25887	0.29670	0.34212
54	Residential ETS	0.19705	0.21390	0.25887	0.29670	0.34212
55	Residential Subtotal	0.19705	0.21390	0.25887	0.29670	0.34212
57	Small General	0.53647	0.58235	0.70478	0.80777	0.93144
58	General Demand	0.27221	0.29549	0.35760	0.40986	0.47261
59	Large General	0.49331	0.53551	0.64808	0.74279	0.85651
60	Small Industrial	0.12599	0.13677	0.16552	0.18971	0.21875
61	Medium Industrial	0.23814	0.25851	0.31286	0.35857	0.41347
62	Large Industrial	0.12914	0.14018	0.16965	0.19444	0.22421
63	ELI 2P-RTP	0.04303	0.04671	0.05653	0.06479	0.07471
64	Municipal	0.32645	0.35437	0.42887	0.49154	0.56680
65	Unmetered	0.38617	0.41919	0.50732	0.58145	0.67047
66	Bowater Mersey (AE)	0.03774	0.04122	0.04946	0.05770	0.06595
67	Gen. Repl./ Load Foll.	0.03052	0.03313	0.04010	0.04596	0.05299
68	Wholesale Market Backup/Top-up	0.00000	0.00000	0.00000	0.00000	0.00000
69	1P-RTP	0.00000	0.00000	0.00000	0.00000	0.00000

Notes:

1 Forecast Program Costs for 2010 are as anticipated. Forecast Program Costs for years 2011-2014 are hypothetical.

TABLE 5 Illustration of Hypothetical DSM Balance Adjustments to the PCR Components in years 2010-2014

Line #	Column	A	B	C	D	E	F	G	H	I	J
2											
3	**Formula**	**Table 4.2**	**Table 4.3**			**B x C / 100**	**(Prior 2 Year Col D - Prior 2 yr Col E) x (1 + WACC)^2**	**Col F / Col A x 100**	**Col C x Col G**	**(Prior 2 Year Col F - Col H) x (1 + WACC)^2**	**Col I / Col A x 100**
4											
5	**Year**	**Forecast**		**Actual**			**BA-PCR Adjustment**		**BA-BA-PCR Adjustment**		
6		kWh Sales net of DSM	PCR Components in cents per kWh	kWh Sales	DSM Program Costs allocated among rate classes[1]	Collected DSM Program Costs	Actual Adjustment Amount (Prior 2 Year)	PCR (Cents / kWh)	Balance Adjustment Amount collected (Prior 2 year)	Balance adjustment amount	DSM Balance Adjustment on BA (cents/kWh)
7		**Total for all rate classes**									
8	2010	11,444,691,400		11,827,728,166	$20,008,132	$23,616,123	$0				
9	2011	11,513,696,062		11,507,555,325	$30,105,853	$24,896,906	$0				
10	2012	11,417,969,983		11,370,130,416	$28,010,580	$29,631,727	($4,226,304)				
11	2013	11,619,329,383		12,045,201,143	$35,990,012	$36,341,318	$6,101,621				
12	2014	11,517,715,971		11,335,120,769	$39,005,010	$39,316,425	($1,898,968)		($4,172,753)	($62,728)	
13		**Residential (Non-ETS and ETS Combined)**									
14	2010	4,121,773,375	0.19705	4,324,989,783	$7,099,381	$8,522,375		**-**			
15	2011	4,147,019,900	0.21390	4,231,751,619	$10,682,302	$9,051,863		**-**			
16	2012	4,111,996,891	0.25887	4,109,384,517	$9,938,847	$10,637,980	($1,666,858)	**(0.040536)**			
17	2013	4,185,667,640	0.29670	4,479,231,311	$12,770,147	$13,289,869	$1,909,853	**0.045628**			
18	2014	4,148,490,651	0.34212	4,041,882,821	$13,839,943	$13,828,259	($818,945)	**(0.019741)**	($1,665,799)	($1,240)	**(0.000030)**
19		**Small General**									
20	2010	244,551,776	0.53647	249,103,485	$1,146,772	$1,336,366		**-**			
21	2011	246,049,695	0.58235	242,431,840	$1,725,526	$1,411,814		**-**			
22	2012	243,971,721	0.70478	236,070,670	$1,605,435	$1,663,774	($222,085)	**(0.091029)**			
23	2013	248,342,731	0.80777	256,572,542	$2,062,779	$2,072,514	$367,474	**0.147971**			
24	2014	246,136,957	0.93144	235,631,349	$2,235,584	$2,194,759	($68,337)	**(0.027764)**	($214,893)	($8,425)	**(0.003423)**
25		**General Demand**									
26	2010	2,440,068,673	0.27221	2,527,605,641	$5,805,767	$6,880,279		**-**			
27	2011	2,455,014,486	0.29549	2,385,361,833	$8,735,826	$7,048,444		**-**			
28	2012	2,434,281,045	0.35760	2,346,094,991	$8,127,840	$8,389,753	($1,258,655)	**(0.051705)**			
29	2013	2,477,893,750	0.40986	2,559,243,537	$10,443,234	$10,489,385	$1,976,554	**0.079768**			
30	2014	2,455,885,164	0.47261	2,338,607,817	$11,318,097	$11,052,547	($306,798)	**(0.012492)**	($1,213,058)	($53,411)	**(0.002175)**

TABLE 5 Illustration of Hypothetical DSM Balance Adjustments to the PCR Components in years 2010-2014

Line #											
1	**Column**	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**
2											
3	**Formula**	**Table 4.2**	**Table 4.3**			**B x C / 100**	**(Prior 2 Year Col D - Prior 2 yr Col E) x (1 + WACC)^2**	**Col F / Col A x 100**	**Col C x Col G**	**(Prior 2 Year Col F - Col H) x (1 + WACC)^2**	**Col I / Col A x 100**
4											
5	**Year**	**Forecast**		**Actual**			**BA-PCR Adjustment**		**BA-BA-PCR Adjustment**		
6		kWh Sales net of DSM	PCR Components in cents per kWh	kWh Sales	DSM Program Costs allocated among rate classes[1]	Collected DSM Program Costs	Actual Adjustment Amount (Prior 2 Year)	PCR (Cents / kWh)	Balance Adjustment Amount collected (Prior 2 year)	Balance adjustment amount	DSM Balance Adjustment on BA (cents/kWh)
31		**Large General**									
32	2010	407,814,993	0.49331	414,091,362	$1,758,517	$2,042,767		**-**			
33	2011	410,312,925	0.53551	407,341,678	$2,646,007	$2,181,341		**-**			
34	2012	406,847,691	0.64808	391,898,638	$2,461,853	$2,539,821	($332,963)	**(0.081840)**			
35	2013	414,136,796	0.74279	401,788,864	$3,163,166	$2,984,435	$544,296	**0.131429**			
36	2014	410,458,444	0.85651	418,314,098	$3,428,155	$3,582,889	($91,330)	**(0.022251)**	($320,728)	($14,331)	**(0.003491)**
37		**Small Industrial**									
38	2010	251,793,465	0.12599	254,175,297	$277,298	$320,240		**-**			
39	2011	253,335,740	0.13677	248,640,744	$417,246	$340,061		**-**			
40	2012	251,196,233	0.16552	235,531,786	$388,207	$389,851	($50,301)	**(0.020024)**			
41	2013	255,696,678	0.18971	242,276,204	$498,796	$459,615	$90,412	**0.035359**			
42	2014	253,425,587	0.21875	241,673,924	$540,582	$528,665	($1,926)	**(0.000760)**	($47,164)	($3,674)	**(0.001450)**
43		**Medium Industrial**									
44	2010	528,170,764	0.23814	531,445,310	$1,099,442	$1,265,598		**-**			
45	2011	531,405,895	0.25851	531,700,576	$1,654,309	$1,374,505		**-**			
46	2012	526,917,989	0.31286	525,997,318	$1,539,174	$1,645,612	($194,631)	**(0.036938)**			
47	2013	536,358,279	0.35857	562,493,115	$1,977,642	$2,016,954	$327,754	**0.061107**			
48	2014	531,594,359	0.41347	555,674,431	$2,143,315	$2,297,554	($124,678)	**(0.023454)**	($194,291)	($398)	**(0.000075)**
49		**Large Industrial**									
50	2010	954,671,070	0.12914	955,052,907	$1,077,603	$1,233,308		**-**			
51	2011	960,518,584	0.14018	938,794,679	$1,621,449	$1,316,004		**-**			
52	2012	952,406,674	0.16965	1,028,577,923	$1,508,601	$1,744,971	($182,389)	**(0.019150)**			
53	2013	969,470,041	0.19444	1,020,733,851	$1,938,359	$1,984,716	$357,790	**0.036906**			
54	2014	960,859,234	0.22421	1,045,993,778	$2,100,742	$2,345,209	($276,878)	**(0.028816)**	($196,976)	$17,087	**0.001778**

TABLE 5 Illustration of Hypothetical DSM Balance Adjustments to the PCR Components in years 2010-2014

Line #											
1	**Column**	A	B	C	D	E	F	G	H	I	J
2											
3	**Formula**	Table 4.2	Table 4.3			B x C / 100	(Prior 2 Year Col D - Prior 2 yr Col E) x (1 + WACC)^2	Col F / Col A x 100	Col C x Col G	(Prior 2 Year Col F - Col H) x (1 + WACC)^2	Col I / Col A x 100
4											
5	Year	Forecast		Actual			BA-PCR Adjustment		BA-BA-PCR Adjustment		
6		kWh Sales net of DSM	PCR Components in cents per kWh	kWh Sales	DSM Program Costs allocated among rate classes[1]	Collected DSM Program Costs	Actual Adjustment Amount (Prior 2 Year)	PCR (Cents / kWh)	Balance Adjustment Amount collected (Prior 2 year)	Balance adjustment amount	DSM Balance Adjustment on BA (cents/kWh)
55		**ELI 2P-RTP**									
56	2010	2,001,034,000	0.04303	2,074,124,011	$752,686	$892,552		-			
57	2011	2,013,290,655	0.04671	2,031,959,328	$1,132,552	$949,196		-			
58	2012	1,996,287,724	0.05653	2,001,595,434	$1,053,730	$1,131,571	($163,835)	**(0.008207)**			
59	2013	2,032,053,318	0.06479	2,026,373,072	$1,353,908	$1,312,984	$214,779	**0.010570**			
60	2014	2,014,004,674	0.07471	1,955,664,438	$1,467,329	$1,461,171	($91,180)	**(0.004527)**	($164,270)	$510	**0.000025**
61		**Municipal**									
62	2010	194,831,512	0.32645	189,256,527	$555,954	$617,831		-			
63	2011	196,024,886	0.35437	192,302,189	$836,533	$681,467		-			
64	2012	194,369,389	0.42887	190,436,034	$778,313	$816,722	($72,481)	**(0.037290)**			
65	2013	197,851,721	0.49154	203,152,271	$1,000,032	$998,578	$181,639	**0.091806**			
66	2014	196,094,407	0.56680	196,959,622	$1,083,808	$1,116,359	($44,992)	**(0.022944)**	($71,014)	($1,718)	**(0.000876)**
67		**Unmetered**									
68	2010	110,463,833	0.38617	111,770,250	$372,867	$431,618		-			
69	2011	111,140,442	0.41919	111,266,932	$561,046	$466,425		-			
70	2012	110,201,822	0.50732	114,012,158	$521,999	$578,404	($68,819)	**(0.062448)**			
71	2013	112,176,204	0.58145	107,729,921	$670,702	$626,399	$110,837	**0.10**			
72	2014	111,179,858	0.67047	117,348,232	$726,889	$786,788	($66,071)	**(0.06)**	($71,199)	$2,787	**0.002507**
73		**Bowater Mersey (AE)**									
74	2010	178,920,000	0.03774	184,761,081	$59,019	$69,725		-			
75	2011	178,920,000	0.04122	175,161,620	$88,804	$72,194		-			
76	2012	178,920,000	0.04946	180,205,411	$82,624	$89,128	($12,541)	**(0.007009)**			
77	2013	178,920,000	0.05770	175,135,357	$106,161	$101,057	$19,456	**0.010874**			
78	2014	178,920,000	0.06595	177,051,287	$115,054	$116,757	($7,619)	**(0.004258)**	($12,631)	$106	**0.000059**

TABLE 5 Illustration of Hypothetical DSM Balance Adjustments to the PCR Components in years 2010-2014

Line #											
1	Column	A	B	C	D	E	F	G	H	I	J
2											
3	Formula	Table 4.2	Table 4.3			B x C / 100	(Prior 2 Year Col D - Prior 2 yr Col E) x $(1 + WACC)^2$	Col F / Col A x 100	Col C x Col G	(Prior 2 Year Col F - Col H) x $(1 + WACC)^2$	Col I / Col A x 100
4											
5	Year	Forecast		Actual			BA-PCR Adjustment		BA-BA-PCR Adjustment		
6		kWh Sales net of DSM	PCR Components in cents per kWh	kWh Sales	DSM Program Costs allocated among rate classes[1]	Collected DSM Program Costs	Actual Adjustment Amount (Prior 2 Year)	PCR (Cents / kWh)	Balance Adjustment Amount collected (Prior 2 year)	Balance adjustment amount	DSM Balance Adjustment on BA (cents/kWh)
79		**Generation Replacement / Load Following**									
80	2010	10,597,940	0.03052	11,352,513	$2,827	$3,465		-			
81	2011	10,662,854	0.03313	10,842,288	$4,254	$3,592		-			
82	2012	10,572,803	0.04010	10,325,535	$3,958	$4,140	($747)	**(0.007064)**			
83	2013	10,762,225	0.04596	10,471,100	$5,086	$4,812	$776	**0.007206**			
84	2014	10,666,636	0.05299	10,318,971	$5,512	$5,468	($213)	**(0.001999)**	($729)	($20)	**(0.000192)**
		Wholesale Market Backup/Top-up									
	2010	-	-	-	$0	$0		-			
	2011	-	-	-	$0	$0		-			
	2012	-	-	-	$0	$0	$0	-			
	2013	-	-	-	$0	$0	$0	-			
	2014	-	-	-	$0	$0	$0	-	$0	$0	-
85		**1P-RTP**									
86	2010	-	-	-	$0	$0		-			
87	2011	-	-	-	$0	$0		-			
88	2012	-	-	-	$0	$0	$0	-			
89	2013	-	-	-	$0	$0	$0	-			
90	2014	-	-	-	$0	$0	$0	-	$0	$0	-

Note:
(1) The actual DSM Program costs are allocated among rate classes using the same methodology and coefficients as presented in tables 1, 2 and 3.

TABLE 6 Calculation of Unit Fixed Costs in cents per kWh recovered under kWh and kW/kVA Charges (Source: COSS Compliance Filing 2009)

Line #																
1																
2																
3	COLUMN	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
4																
5	FORMULA					C - D					F + G + H + I	J x A	K / K (line 22)	L x J (line 22)	E - M	N / B
6																
7				Revenues			Variable Costs from COS (1)					Variable Cost adjusted for R/C Ratio			Fixed Costs recovered through energy and demand charges	
8	Rate Class	R/C Ratio	kWhs Sales	Total	Customer Charge	Net of Customer Charges	Fuel	O&M	Purchased Power	Export Revenues (2)	Total	Unbalanced	Relative Share	Balanced	Total	cents per kWh
9	Residential non ETS		4,028,924,217	$529,237,480	$53,986,792	$475,250,688										
10	Residential ETS		156,814,823	$13,591,853	$1,288,191	$12,303,661										
11	Residential Subtotal (3)	98.9%	4,185,739,040	$542,829,333	$55,274,983	$487,554,350	$185,893,097	$5,436,690	$9,294,700	($1,710,857)	$198,913,630	$196,735,666	37.1%	$197,704,754	$289,849,596	6.925
12																
13	Small General	102.3%	255,123,322	$33,579,417	$3,643,048	$29,936,369	$11,277,981	$329,583	$563,378	($103,700)	$12,067,243	$12,347,021	2.3%	$12,407,841	$17,528,528	6.871
14	General Demand	107.2%	2,561,920,799	$276,550,575		$276,550,575	$108,981,921	$3,185,531	$5,445,986	($1,002,432)	$116,611,007	$124,971,598	23.6%	$125,587,188	$150,963,387	5.893
15	Large General	98.7%	426,405,529	$38,039,305		$38,039,305	$17,958,819	$524,769	$897,284	($165,161)	$19,215,711	$18,963,843	3.6%	$19,057,256	$18,982,049	4.452
16	Small Industrial	102.0%	252,430,586	$26,106,536		$26,106,536	$10,674,259	$311,900	$533,290	($98,162)	$11,421,287	$11,649,624	2.2%	$11,707,009	$14,399,528	5.704
17	Medium Industrial	100.8%	580,177,520	$53,164,297		$53,164,297	$24,438,466	$714,429	$1,221,275	($224,798)	$26,149,372	$26,356,644	5.0%	$26,486,473	$26,677,824	4.598
18	Large Industrial	97.5%	964,779,220	$71,050,464		$71,050,464	$39,909,375	$1,166,031	$1,993,318	($366,906)	$42,701,818	$41,651,836	7.9%	$41,857,006	$29,193,457	3.026
19	ELI 2P-RTP	91.0%	2,098,260,493	$130,325,730	$496,800	$129,828,930	$84,959,427	$2,485,692	$4,249,586	($782,213)	$90,912,492	$82,721,698	15.6%	$83,129,171	$46,699,759	2.226
20	Municipal	99.8%	198,399,410	$17,611,752		$17,611,752	$8,274,287	$241,827	$413,475	($76,108)	$8,853,482	$8,838,940	1.7%	$8,882,479	$8,729,273	4.400
21	Unmetered (4)	100.0%	115,632,849	$12,101,303		$12,101,303	$5,097,138	$148,987	$254,873	($46,914)	$5,454,083	$5,454,083	1.0%	$5,480,949	$6,620,354	5.725
22	Total / Average	100.0%	11,638,868,769	$1,201,358,713	$59,414,831	$1,141,943,881	$497,464,769	$14,545,440	$24,867,166	($4,577,250)	$532,300,125	$529,690,954	100.0%	$532,300,125	$609,643,756	5.238

23 (1) Variable costs are made up of the following items in the cost of service studies:

24 1 Fuel costs (line 1, page 3, exh 6);

25 2 Variable Purchased Power (lines 4 and 6, page 3, exh 6);

26 3 Variable O&M costs (16% of O&M - Steam (line 7, page 1, exh 5) allocated among rate classes using distribution pattern of O&M - Steam Energy-related (line 7, page 3, exh 6)

27 4 Export sales (line 14, page 3, exh 6);

28 (2) Export Revenues were inadvertently excluded from the variable cost calculations in the 2008 DSM submission.

29 (3) All residential rate classes will use the same unit fixed cost estimate.

30 (4) The unmetered class revenue relfects only electric service costs. It does not reflect the maintanance and capital costs associated with unmetered fixtures such as lamp posts.

TABLE 7 Illustration of Calculations of Hypothetical LCFC Components in years 2010-2014

Line #	Column	A	B	C	D	E	F	G	H	I	J	K
2												
3												
4		Fixed Unit Costs in cents per kWh (Source: Table 6; Col N)	Table 7.1 Forecast engineering estimates of DSM-induced kWh reduction					Table 7.2 Forecast forgone recovery of fixed costs due to the DSM-effect				
5												
6			2010	2011	2012	2013	2014	2010	2011	2012	2013	2014
7	**Rate Class**											
8	Residential non ETS	6.92	15,517,942	17,216,150	21,267,008	24,305,152	28,356,011	$1,074,570	$1,192,166	$1,472,675	$1,683,057	$1,963,567
9	Residential ETS	6.92	644,888	715,462	883,806	1,010,064	1,178,408	$44,657	$49,544	$61,201	$69,944	$81,601
10	Small General	6.87	4,597,661	5,100,806	6,300,996	7,201,138	8,401,328	$315,887	$350,457	$432,917	$494,762	$577,222
11	General Demand	5.89	24,662,338	27,361,264	33,799,208	38,627,666	45,065,611	$1,453,250	$1,612,286	$1,991,647	$2,276,168	$2,655,530
12	Large General	4.45	12,703,630	14,093,853	17,410,053	19,897,204	23,213,404	$565,520	$627,408	$775,033	$885,752	$1,033,378
13	Small Industrial	5.70	630,592	699,601	864,213	987,672	1,152,284	$35,971	$39,908	$49,298	$56,340	$65,730
14	Medium Industrial	4.60	6,964,536	7,726,701	9,544,748	10,908,283	12,726,331	$320,245	$355,291	$438,888	$501,587	$585,184
15	Large Industrial	3.03	5,843,489	6,482,971	8,008,376	9,152,430	10,677,835	$176,819	$196,170	$242,327	$276,945	$323,103
16	ELI 2P-RTP	2.23	-	-	-	-	-	$0	$0	$0	$0	$0
17	Municipal	4.40	2,702,873	2,998,662	3,704,229	4,233,405	4,938,972	$118,922	$131,937	$162,980	$186,263	$217,307
18	Unmetered	5.73	2,347,619	2,604,531	3,217,361	3,676,985	4,289,815	$134,409	$149,118	$184,204	$210,519	$245,606
19	Bowater Mersey (AE)	-	-	-	-	-	-	$0	$0	$0	$0	$0
20	Gen. Repl./ Load Foll.	-	-	-	-	-	-	$0	$0	$0	$0	$0
	Wholesale Market Backup/Top-up	-	-	-	-	-	-	$0	$0	$0	$0	$0
21	1P-RTP	-	-	-	-	-	-	$0	$0	$0	$0	$0
22	Total		76,615,568	85,000,000	105,000,000	120,000,000	140,000,000	$4,240,250	$4,704,282	$5,811,172	$6,641,339	$7,748,229
23												
24												
25		Fixed Unit Costs in cents per kWh (Source: Table 6; Col N)	Table 7.3 Actual engineering estimates of DSM-induced kWh reduction					Table 7.4 Actual forgone recovery of fixed costs due to the DSM-effect				
26												
27			2010	2011	2012	2013	2014	2010	2011	2012	2013	2014
28	**Rate Class**											
29	Residential non ETS	6.92	15,905,800	17,048,930	20,730,915	23,193,957	31,214,296	$1,101,428	$1,180,586	$1,435,552	$1,606,110	$2,161,494
30	Residential ETS	6.92	656,660	657,052	905,946	873,631	1,205,375	$45,472	$45,499	$62,734	$60,496	$83,468
31	Small General	6.87	4,221,242	4,780,735	6,424,308	7,430,890	8,837,977	$290,025	$328,466	$441,389	$510,547	$607,223
32	General Demand	5.89	24,352,337	26,759,536	33,990,336	37,711,717	43,210,433	$1,434,982	$1,576,829	$2,002,910	$2,222,195	$2,546,212
33	Large General	4.45	12,570,413	14,080,042	18,254,282	19,138,903	22,676,035	$559,590	$626,793	$812,615	$851,995	$1,009,456
34	Small Industrial	5.70	667,273	692,071	825,934	924,019	1,157,973	$38,064	$39,478	$47,114	$52,709	$66,055
35	Medium Industrial	4.60	6,595,269	7,808,677	9,186,124	10,164,808	12,394,861	$303,265	$359,060	$422,398	$467,400	$569,943
36	Large Industrial	3.03	6,121,790	7,143,409	8,291,846	9,731,378	10,891,029	$185,241	$216,154	$250,905	$294,464	$329,554
37	ELI 2P-RTP	2.23	-	-	-	-	-	$0	$0	$0	$0	$0
38	Municipal	4.40	2,656,695	2,976,241	3,779,749	3,971,435	4,863,950	$116,891	$130,950	$166,303	$174,737	$214,006
39	Unmetered	5.73	2,436,333	2,611,810	2,964,934	3,628,727	3,972,327	$139,488	$149,535	$169,752	$207,756	$227,429
40	Bowater Mersey (AE)	-	-	-	-	-	-	$0	$0	$0	$0	$0
41	Gen. Repl./ Load Foll.	-	-	-	-	-	-	$0	$0	$0	$0	$0
	Wholesale Market Backup/Top-up	-	-	-	-	-	-	$0	$0	$0	$0	$0
42	1P-RTP	-	-	-	-	-	-	$0	$0	$0	$0	$0
43	Total		76,183,812	84,558,502	105,354,373	116,769,464	140,424,255	$4,214,444	$4,653,349	$5,811,673	$6,448,412	$7,814,840

TABLE 7 Illustration of Calculations of Hypothetical LCFC Components in years 2010-2014

Line #	Column	A	B	C	D	E	F	G	H	I	J	K
44			Table 7.5 Forecast cumulative engineering estimates of DSM-induced kWh reduction					Table 7.6 Forecast cumulative forgone recovery of fixed costs due to the DSM-effect				
46			2010	2011	2012	2013	2014	2010	2011	2012	2013	2014
47	**Rate Class**											
48	Residential non ETS		15,517,942	32,734,092	54,388,958	78,526,891	106,346,809	$1,074,570	$2,266,736	$3,766,269	$5,437,746	$7,364,190
49	Residential ETS		644,888	1,360,350	2,255,927	3,207,581	4,408,128	$44,657	$94,200	$156,216	$222,115	$305,249
50	Small General		4,597,661	9,698,467	15,623,044	22,504,111	31,028,751	$315,887	$666,344	$1,073,398	$1,546,170	$2,131,864
51	General Demand		24,662,338	52,023,602	85,512,808	123,538,747	168,795,486	$1,453,250	$3,065,536	$5,038,916	$7,279,627	$9,946,419
52	Large General		12,703,630	26,797,482	44,074,319	63,957,712	88,015,345	$565,520	$1,192,928	$1,962,031	$2,847,169	$3,918,128
53	Small Industrial		630,592	1,330,193	2,231,087	3,211,229	4,325,235	$35,971	$75,879	$127,269	$183,180	$246,727
54	Medium Industrial		6,964,536	14,691,237	23,866,718	34,856,978	47,224,684	$320,245	$675,535	$1,097,444	$1,602,800	$2,171,494
55	Large Industrial		5,843,489	12,326,460	20,613,138	30,426,005	41,387,310	$176,819	$372,989	$623,737	$920,667	$1,252,347
56	ELI 2P-RTP		-	-	-	-	-	$0	$0	$0	$0	$0
57	Municipal		2,702,873	5,701,535	9,359,586	13,570,570	18,585,061	$118,922	$250,859	$411,808	$597,084	$817,715
58	Unmetered		2,347,619	4,952,150	8,258,226	11,942,490	15,979,877	$134,409	$283,527	$472,810	$683,746	$914,900
59	Bowater Mersey (AE)		-	-	-	-	-	$0	$0	$0	$0	$0
60	Gen. Repl./ Load Foll.		-	-	-	-	-	$0	$0	$0	$0	$0
	Wholesale Market Backup/Top-up		-	-	-	-	-	$0	$0	$0	$0	$0
61	1P-RTP		-	-	-	-	-	$0	$0	$0	$0	$0
62	Total		76,615,568	161,615,568	266,183,812	385,742,314	526,096,687	$4,240,250	$8,944,531	$14,729,898	$21,320,304	$29,069,034

Line #	Column	A	B	C	D	E	F	G	H	I	J	K
63			Table 7.7 Forecast kWh sales reflecting DSM-effect					Table 7.8 Forecast LCFC components by class and year (cents/kWh)				
65			2010	2011	2012	2013	2014	2010	2011	2012	2013	2014
66	**Rate Class**											
67	Residential non ETS		3,957,309,244	3,981,548,400	3,947,922,855	4,018,654,045	3,982,960,466	0.02715	0.05693	0.09540	0.13531	0.18489
68	Residential ETS		164,464,131	165,471,500	164,074,036	167,013,595	165,530,185	0.02715	0.05693	0.09521	0.13299	0.18441
69	Small General		244,551,776	246,049,695	243,971,721	248,342,731	246,136,957	0.12917	0.27082	0.43997	0.62260	0.86613
70	General Demand		2,440,068,673	2,455,014,486	2,434,281,045	2,477,893,750	2,455,885,164	0.05956	0.12487	0.20700	0.29378	0.40500
71	Large General		407,814,993	410,312,925	406,847,691	414,136,796	410,458,444	0.13867	0.29074	0.48225	0.68749	0.95457
72	Small Industrial		251,793,465	253,335,740	251,196,233	255,696,678	253,425,587	0.01429	0.02995	0.05067	0.07164	0.09736
73	Medium Industrial		528,170,764	531,405,895	526,917,989	536,358,279	531,594,359	0.06063	0.12712	0.20828	0.29883	0.40849
74	Large Industrial		954,671,070	960,518,584	952,406,674	969,470,041	960,859,234	0.01852	0.03883	0.06549	0.09497	0.13034
75	ELI 2P-RTP		2,001,034,000	2,013,290,655	1,996,287,724	2,032,053,318	2,014,004,674	-	-	-	-	-
76	Municipal		194,831,512	196,024,886	194,369,389	197,851,721	196,094,407	0.06104	0.12797	0.21187	0.30178	0.41700
77	Unmetered		110,463,833	111,140,442	110,201,822	112,176,204	111,179,858	0.12168	0.25511	0.42904	0.60953	0.82290
78	Bowater Mersey (AE)		178,920,000	178,920,000	178,920,000	178,920,000	178,920,000	-	-	-	-	-
79	Gen. Repl./ Load Foll.		10,597,940	10,662,854	10,572,803	10,762,225	10,666,636	-	-	-	-	-
	Wholesale Market Backup/Top-up		-	-	-	-	-	-	-	-	-	-
80	1P-RTP		-	-	-	-	-	-	-	-	-	-
81	Total		11,444,691,400	11,513,696,062	11,417,969,983	11,619,329,383	11,517,715,971					

82 **LCFC CALCULATIONS**

83 (1) For each year and each rate class the forecast forgone recovery of fixed costs due to the DSM-effect (Table 7.2) are calculated by multiplying Forecast engineering estimates of DSM-induced kwh reduction (Table 7.1) by Fixed Unit Costs in cents/kWh (column A).

84 (2) For each year and each rate class Actual forgone recovery of fixed costs due to the DSM effect (Table 7.4) are calculated by multiplying Actual engineering estimates of DSM-induced kwh reduction (Table 7.3) by Fixed Unit Costs in cents/kWh (column A) Note that fixed unit costs used here are the same as in step 1.

85 (3) For each year and rate class Forecast cumulative forgone recovery of fixed costs due to the DSM effect (Table 7.6) are calculated by adding Actual forgone recovery of fixed cost due to the DSM effect (Table 7.4) to Forecast forgone recovery of fixed costs due to the DSM effect from the current and next year (Table 7.2).

86 (4) LCFC charges for each year and each class are calculated by dividing Forecast cumulative forgone recovery of fixed costs due to the DSM-effect (Table 7.6) by Forecast kWh sales reflecting DSM-effect (Table 7.7).

TABLE 8 Illustration of Hypothetical DSM Balance Adjustments to the LCFC Components in years 2010-2014

Line #														
1	Column	A	B	C	D	E	F	G	H	I	J	K	L	M
2														
3	Formula	Table 7.7	Table 5 Column N	Table 7.8		B X D / 100			C X G / 100	(Prior 2 Year Col F - Prior 2 yr Col H) x $(1 + WACC)^2$	Col I / Col A x 100	Col G x Col J	(Prior 2 Year Col I - Col K) x $(1 + WACC)^2$	Col L / Col A x 100
6	Year	Forecast			Actual					BA-LCFC Adjustment		BA-BA-LCFC Adjustment		
7			Cents per kWh		Forgone recovery of fixed costs			Collected forgone fixed costs						
8		kWh Sales net of DSM	Fixed Unit Costs	LCFC components	DSM-induced reduction in kWh Sales	Amount	Cumulative Amount	kWh Sales	Amount	Actual Adjustment Amount	LCFC (Cents / kWh)	Balance Adjustment Amount collected	Balance adjustment amount	DSM Balance Adjustment on BA (Cents/kWh)
9														
10		Total for all rate classes												
11														
12	2010	11,444,691,400			76,183,812	$4,214,444	$4,214,444	11,827,728,166	$4,362,732	$0				
13	2011	11,513,696,062			84,558,502	$4,653,349	$8,867,793	11,507,555,325	$8,873,451	$0				
14	2012	11,417,969,983			105,354,373	$5,811,673	$14,679,466	11,370,130,416	$14,486,036	($173,700)				
15	2013	11,619,329,383			116,769,464	$6,448,412	$21,127,878	12,045,201,143	$22,028,501	($6,627)				
16	2014	11,517,715,971			140,424,255	$7,814,840	$28,942,718	11,335,120,769	$28,633,188	$226,579		($168,354)	($6,262)	
17		Residential Non-ETS												
18														
19	2010	3,957,309,244	6.925	0.02715	15,905,800	$1,101,428	$1,101,428	4,137,592,060	$1,123,524		-			
20	2011	3,981,548,400	6.925	0.05693	17,048,930	$1,180,586	$2,282,014	4,061,152,196	$2,312,055		-			
21	2012	3,947,922,855	6.925	0.09540	20,730,915	$1,435,552	$3,717,566	3,936,121,857	$3,755,011	($25,883)	**(0.000656)**			
22	2013	4,018,654,045	6.925	0.13531	23,193,957	$1,606,110	$5,323,677	4,293,570,320	$5,809,743	($35,189)	**(0.000876)**			
23	2014	3,982,960,466	6.925	0.18489	31,214,296	$2,161,494	$7,485,171	3,875,036,607	$7,164,647	($43,861)	**(0.001101)**	($25,805)	($91)	**(0.000002)**
24		Residential ETS												
25														
26	2010	164,464,131	6.925	0.02715	656,660	$45,472	$45,472	187,397,723	$50,884		-			
27	2011	165,471,500	6.925	0.05693	657,052	$45,499	$90,970	170,599,423	$97,119		-			
28	2012	164,074,036	6.925	0.09521	905,946	$62,734	$153,704	173,262,660	$164,965	($6,339)	**(0.003864)**			
29	2013	167,013,595	6.925	0.13299	873,631	$60,496	$214,201	185,660,991	$246,915	($7,203)	**(0.004313)**			
30	2014	165,530,185	6.925	0.18441	1,205,375	$83,468	$297,669	166,846,215	$307,676	($13,190)	**(0.007968)**	($6,694)	$416	**0.000251**
31	Small General													
32														
33	2010	244,551,776	6.871	0.12917	4,221,242	$290,025	$290,025	249,103,485	$321,767		-			
34	2011	246,049,695	6.871	0.27082	4,780,735	$328,466	$618,491	242,431,840	$656,546		-			
35	2012	243,971,721	6.871	0.43997	6,424,308	$441,389	$1,059,880	236,070,670	$1,038,636	($37,181)	**(0.015240)**			
36	2013	248,342,731	6.871	0.62260	7,430,890	$510,547	$1,570,427	256,572,542	$1,597,408	($44,577)	**(0.017950)**			
37	2014	246,136,957	6.871	0.86613	8,837,977	$607,223	$2,177,650	235,631,349	$2,040,872	$24,884	**0.010110**	($35,977)	($1,410)	**(0.000573)**
38	General Demand													
39														
40	2010	2,440,068,673	5.893	0.05956	24,352,337	$1,434,982	$1,434,982	2,527,605,641	$1,505,385		-			
41	2011	2,455,014,486	5.893	0.12487	26,759,536	$1,576,829	$3,011,811	2,385,361,833	$2,978,561		-			
42	2012	2,434,281,045	5.893	0.20700	33,990,336	$2,002,910	$5,014,721	2,346,094,991	$4,856,372	($82,467)	**(0.003388)**			
43	2013	2,477,893,750	5.893	0.29378	37,711,717	$2,222,195	$7,236,916	2,559,243,537	$7,518,619	$38,948	**0.001572**			
44	2014	2,455,885,164	5.893	0.40500	43,210,433	$2,546,212	$9,783,128	2,338,607,817	$9,471,442	$185,485	**0.007553**	($79,480)	($3,499)	**(0.000142)**

TABLE 8 Illustration of Hypothetical DSM Balance Adjustments to the LCFC Components in years 2010-2014

Line #		A	B	C	D	E	F	G	H	I	J	K	L	M
1	Column	A	B	C	D	E	F	G	H	I	J	K	L	M
2														
3	Formula	Table 7.7	Table 5 Column N	Table 7.8		B X D / 100			C X G / 100	(Prior 2 Year Col F - Prior 2 yr Col H) x (1 + WACC)^2	Col I / Col A x 100	Col G x Col J	(Prior 2 Year Col I - Col K) x (1 + WACC)^2	Col L / Col A x 100
6	Year	Forecast			Actual					BA-LCFC Adjustment		BA-BA-LCFC Adjustment		
7			Cents per kWh		Forgone recovery of fixed costs			Collected forgone fixed costs						
8		kWh Sales net of DSM	Fixed Unit Costs	LCFC components	DSM-induced reduction in kWh Sales	Amount	Cumulative Amount	kWh Sales	Amount	Actual Adjustment Amount	LCFC (Cents / kWh)	Balance Adjustment Amount collected	Balance adjustment amount	DSM Balance Adjustment on BA (Cents/kWh)
9														
45		**Large General**												
46														
47	2010	407,814,993	4.452	0.13867	12,570,413	$559,590	$559,590	414,091,362	$574,224		-			
48	2011	410,312,925	4.452	0.29074	14,080,042	$626,793	$1,186,383	407,341,678	$1,184,290		-			
49	2012	406,847,691	4.452	0.48225	18,254,282	$812,615	$1,998,998	391,898,638	$1,889,939	($17,142)	**(0.004213)**			
50	2013	414,136,796	4.452	0.68749	19,138,903	$851,995	$2,850,994	401,788,864	$2,762,277	$2,452	**0.000592**			
51	2014	410,458,444	4.452	0.95457	22,676,035	$1,009,456	$3,860,450	418,314,098	$3,993,116	$127,749	**0.031124**	($16,512)	($738)	**(0.000180)**
52		**Small Industrial**												
53														
54	2010	251,793,465	5.704	0.01429	667,273	$38,064	$38,064	254,175,297	$36,311		-			
55	2011	253,335,740	5.704	0.02995	692,071	$39,478	$77,542	248,640,744	$74,473		-			
56	2012	251,196,233	5.704	0.05067	825,934	$47,114	$124,656	235,531,786	$119,333	$2,052	**0.000817**			
57	2013	255,696,678	5.704	0.07164	924,019	$52,709	$177,365	242,276,204	$173,565	$3,595	**0.001406**			
58	2014	253,425,587	5.704	0.09736	1,157,973	$66,055	$243,420	241,673,924	$235,286	$6,236	**0.002461**	$1,924	$150	**0.000059**
59		**Medium Industrial**												
60														
61	2010	528,170,764	4.598	0.06063	6,595,269	$303,265	$303,265	531,445,310	$322,230		-			
62	2011	531,405,895	4.598	0.12712	7,808,677	$359,060	$662,325	531,700,576	$675,910		-			
63	2012	526,917,989	4.598	0.20828	9,186,124	$422,398	$1,084,723	525,997,318	$1,095,526	($22,215)	**(0.004216)**			
64	2013	536,358,279	4.598	0.29883	10,164,808	$467,400	$1,552,123	562,493,115	$1,680,898	($15,913)	**(0.002967)**			
65	2014	531,594,359	4.598	0.40849	12,394,861	$569,943	$2,122,065	555,674,431	$2,269,858	($12,655)	**(0.002381)**	($22,176)	($45)	**(0.000009)**
66		**Large Industrial**												
67														
68	2010	954,671,070	3.026	0.01852	6,121,790	$185,241	$185,241	955,052,907	$176,890		-			
69	2011	960,518,584	3.026	0.03883	7,143,409	$216,154	$401,394	938,794,679	$364,553		-			
70	2012	952,406,674	3.026	0.06549	8,291,846	$250,905	$652,299	1,028,577,923	$673,622	$9,781	**0.001027**			
71	2013	969,470,041	3.026	0.09497	9,731,378	$294,464	$946,763	1,020,733,851	$969,350	$43,155	**0.004451**			
72	2014	960,859,234	3.026	0.13034	10,891,029	$329,554	$1,276,317	1,045,993,778	$1,363,308	($24,977)	**(0.002599)**	$10,564	($916)	**(0.000095)**
73		**ELI 2P-RTP**												
74														
75	2010	2,001,034,000	2.226	-	-	$0	$0	2,074,124,011	$0		-			
76	2011	2,013,290,655	2.226	-	-	$0	$0	2,031,959,328	$0		-			
77	2012	1,996,287,724	2.226	-	-	$0	$0	2,001,595,434	$0	$0	-			
78	2013	2,032,053,318	2.226	-	-	$0	$0	2,026,373,072	$0	$0	-			
79	2014	2,014,004,674	2.226	-	-	$0	$0	1,955,664,438	$0	$0	-	$0	$0	-

TABLE 8 Illustration of Hypothetical DSM Balance Adjustments to the LCFC Components in years 2010-2014

Line #		A	B	C	D	E	F	G	H	I	J	K	L	M
1	Column	A	B	C	D	E	F	G	H	I	J	K	L	M
3	Formula	Table 7.7	Table 5 Column N	Table 7.8		B X D / 100			C X G / 100	(Prior 2 Year Col F - Prior 2 yr Col H) x (1 + WACC)^2	Col I / Col A x 100	Col G x Col J	(Prior 2 Year Col I - Col K) x (1 + WACC)^2	Col L / Col A x 100
6	Year	Forecast			Actual					BA-LCFC Adjustment		BA-BA-LCFC Adjustment		
7			Cents per kWh		Forgone recovery of fixed costs			Collected forgone fixed costs						
8		kWh Sales net of DSM	Fixed Unit Costs	LCFC components	DSM-induced reduction in kWh Sales	Amount	Cumulative Amount	kWh Sales	Amount	Actual Adjustment Amount	LCFC (Cents / kWh)	Balance Adjustment Amount collected	Balance adjustment amount	DSM Balance Adjustment on BA (Cents/kWh)
80		**Municipal**												
82	2010	194,831,512	4.400	0.06104	2,656,695	$116,891	$116,891	189,256,527	$115,519		-			
83	2011	196,024,886	4.400	0.12797	2,976,241	$130,950	$247,841	192,302,189	$246,095		-			
84	2012	194,369,389	4.400	0.21187	3,779,749	$166,303	$414,144	190,436,034	$403,474	$1,606	**0.000826**			
85	2013	197,851,721	4.400	0.30178	3,971,435	$174,737	$588,881	203,152,271	$613,081	$2,045	**0.001034**			
86	2014	196,094,407	4.400	0.41700	4,863,950	$214,006	$802,887	196,959,622	$821,322	$12,498	**0.006374**	$1,574	$38	**0.000019**
87		**Unmetered**												
89	2010	110,463,833	5.725	0.12168	2,436,333	$139,488	$139,488	111,770,250	$135,998		-			
90	2011	111,140,442	5.725	0.25511	2,611,810	$149,535	$289,023	111,266,932	$283,849		-			
91	2012	110,201,822	5.725	0.42904	2,964,934	$169,752	$458,775	114,012,158	$489,158	$4,088	**0.003709**			
92	2013	112,176,204	5.725	0.60953	3,628,727	$207,756	$666,531	107,729,921	$656,645	$6,060	**0.005402**			
93	2014	111,179,858	5.725	0.82290	3,972,327	$227,429	$893,959	117,348,232	$965,659	($35,590)	**(0.032011)**	$4,229	($166)	**(0.000149)**
94		**Bowater Mersey (AE)**												
96	2010	178,920,000	-	-	-	$0	$0	184,761,081	$0		-			
97	2011	178,920,000	-	-	-	$0	$0	175,161,620	$0		-			
98	2012	178,920,000	-	-	-	$0	$0	180,205,411	$0	$0	-			
99	2013	178,920,000	-	-	-	$0	$0	175,135,357	$0	$0	-			
100	2014	178,920,000	-	-	-	$0	$0	177,051,287	$0	$0	-	$0	$0	-
101		**Generation Replacement / Load Following**												
103	2010	10,597,940	-	-	-	$0	$0	11,352,513	$0		-			
104	2011	10,662,854	-	-	-	$0	$0	10,842,288	$0		-			
105	2012	10,572,803	-	-	-	$0	$0	10,325,535	$0	$0	-			
106	2013	10,762,225	-	-	-	$0	$0	10,471,100	$0	$0	-			
107	2014	10,666,636	-	-	-	$0	$0	10,318,971	$0	$0	-	$0	$0	-
108		**Wholesale Market Backup/Top-up**												
110	2010	-	-	-	-	$0	$0	-	$0		-			
111	2011	-	-	-	-	$0	$0	-	$0		-			
112	2012	-	-	-	-	$0	$0	-	$0	$0	-			
113	2013	-	-	-	-	$0	$0	-	$0	$0	-			
114	2014	-	-	-	-	$0	$0	-	$0	$0	-	$0	$0	-
115		**1P-RTP**												
117	2010	-	-	-	-	$0	$0	-	$0		-			
118	2011	-	-	-	-	$0	$0	-	$0		-			
119	2012	-	-	-	-	$0	$0	-	$0	$0	-			
120	2013	-	-	-	-	$0	$0	-	$0	$0	-			
121	2014	-	-	-	-	$0	$0	-	$0	$0	-	$0	$0	-

TABLE 9 Illustration of Hypothetical DSM Rider Components (in cents per kWh) in years 2010-2014

Line #										
1										
2	COLUMN	A	B	C	D	E	F	G	H	I
	FORMULA	Table 4.3	Table 7.8	Table 5 Column G	Table 8 Column J	Table 5 Column J	Table 8 Column M	E + F	C + D + G	A + B + H
3										
4						2010				
5		PCR	LCFC	BA						DCRR
6	Rate Class			PCR	LCFC	BA			Total	
7						PCR	LCFC	Total		
8	Residential non ETS	0.19705	0.02715	-	-	-	-	-	-	**0.22420**
9	Residential ETS	0.19705	0.02715	-	-	-	-	-	-	**0.22420**
10	Small General	0.53647	0.12917	-	-	-	-	-	-	**0.66564**
11	General Demand	0.27221	0.05956	-	-	-	-	-	-	**0.33176**
12	Large General	0.49331	0.13867	-	-	-	-	-	-	**0.63198**
13	Small Industrial	0.12599	0.01429	-	-	-	-	-	-	**0.14028**
14	Medium Industrial	0.23814	0.06063	-	-	-	-	-	-	**0.29878**
15	Large Industrial	0.12914	0.01852	-	-	-	-	-	-	**0.14766**
16	ELI 2P-RTP	0.04303	-	-	-	-	-	-	-	**0.04303**
17	Municipal	0.32645	0.06104	-	-	-	-	-	-	**0.38749**
18	Unmetered	0.38617	0.12168	-	-	-	-	-	-	**0.50784**
19	Bowater Mersey (AE)	0.03774	-	-	-	-	-	-	-	**0.03774**
20	GRLF.	0.03052	-	-	-	-	-	-	-	**0.03052**
21	W.M. Backup/Top-up	-	-	-	-	-	-	-	-	**-**
22	1P-RTP	-	-	-	-	-	-	-	-	**-**
23						2011				
24		PCR	LCFC	BA						DCRR
25	Rate Class			PCR	LCFC	BA			Total	
26						PCR	LCFC	Total		
27	Residential non ETS	0.21390	0.05693	-	-	-	-	-	-	**0.27083**
28	Residential ETS	0.21390	0.05693	-	-	-	-	-	-	**0.27083**
29	Small General	0.58235	0.27082	-	-	-	-	-	-	**0.85317**
30	General Demand	0.29549	0.12487	-	-	-	-	-	-	**0.42036**
31	Large General	0.53551	0.29074	-	-	-	-	-	-	**0.82624**
32	Small Industrial	0.13677	0.02995	-	-	-	-	-	-	**0.16672**
33	Medium Industrial	0.25851	0.12712	-	-	-	-	-	-	**0.38563**
34	Large Industrial	0.14018	0.03883	-	-	-	-	-	-	**0.17901**
35	ELI 2P-RTP	0.04671	-	-	-	-	-	-	-	**0.04671**
36	Municipal	0.35437	0.12797	-	-	-	-	-	-	**0.48235**
37	Unmetered	0.41919	0.25511	-	-	-	-	-	-	**0.67430**
38	Bowater Mersey (AE)	0.04122	-	-	-	-	-	-	-	**0.04122**
39	GRLF.	0.03313	-	-	-	-	-	-	-	**0.03313**
40	W.M. Backup/Top-up	-	-	-	-	-	-	-	-	**-**
41	1P-RTP	-	-	-	-	-	-	-	-	**-**
42						2012				
43		PCR	LCFC	BA						DCRR
44	Rate Class			PCR	LCFC	BA			Total	
45						PCR	LCFC	Total		
46	Residential non ETS	0.25887	0.09540	(0.04054)	(0.00066)	-	-	-	(0.04119)	**0.31308**
47	Residential ETS	0.25887	0.09521	(0.04054)	(0.00386)	-	-	-	(0.04440)	**0.30968**
48	Small General	0.70478	0.43997	(0.09103)	(0.01524)	-	-	-	(0.10627)	**1.03848**
49	General Demand	0.35760	0.20700	(0.05171)	(0.00339)	-	-	-	(0.05509)	**0.50951**
50	Large General	0.64808	0.48225	(0.08184)	(0.00421)	-	-	-	(0.08605)	**1.04428**
51	Small Industrial	0.16552	0.05067	(0.02002)	0.00082	-	-	-	(0.01921)	**0.19698**
52	Medium Industrial	0.31286	0.20828	(0.03694)	(0.00422)	-	-	-	(0.04115)	**0.47998**
53	Large Industrial	0.16965	0.06549	(0.01915)	0.00103	-	-	-	(0.01812)	**0.21702**
54	ELI 2P-RTP	0.05653	-	(0.00821)	-	-	-	-	(0.00821)	**0.04833**
55	Municipal	0.42887	0.21187	(0.03729)	0.00083	-	-	-	(0.03646)	**0.60427**
56	Unmetered	0.50732	0.42904	(0.06245)	0.00371	-	-	-	(0.05874)	**0.87762**
57	Bowater Mersey (AE)	0.04946	-	(0.00701)	-	-	-	-	(0.00701)	**0.04245**
58	GRLF.	0.04010	-	(0.00706)	-	-	-	-	(0.00706)	**0.03303**
59	W.M. Backup/Top-up	-	-	-	-	-	-	-	-	**-**
60	1P-RTP	-	-	-	-	-	-	-	-	**-**

TABLE 9 Illustration of Hypothetical DSM Rider Components (in cents per kWh) in years 2010-2014

Line #										
1										
2	**COLUMN**	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**
	FORMULA	**Table 4.3**	**Table 7.8**	**Table 5 Column G**	**Table 8 Column J**	**Table 5 Column J**	**Table 8 Column M**	**E + F**	**C + D + G**	**A + B + H**
3										
61		**2013**								
62		**PCR**	**LCFC**	**BA**						**DCRR**
63	**Rate Class**			**PCR**	**LCFC**	**BA**			**Total**	
64						**PCR**	**LCFC**	**Total**		
65	Residential non ETS	0.29670	0.13531	0.04563	(0.00088)	-	-	-	0.04475	**0.47677**
66	Residential ETS	0.29670	0.13299	0.04563	(0.00431)	-	-	-	0.04132	**0.47101**
67	Small General	0.80777	0.62260	0.14797	(0.01795)	-	-	-	0.13002	**1.56038**
68	General Demand	0.40986	0.29378	0.07977	0.00157	-	-	-	0.08134	**0.78498**
69	Large General	0.74279	0.68749	0.13143	0.00059	-	-	-	0.13202	**1.56230**
70	Small Industrial	0.18971	0.07164	0.03536	0.00141	-	-	-	0.03677	**0.29811**
71	Medium Industrial	0.35857	0.29883	0.06111	(0.00297)	-	-	-	0.05814	**0.71554**
72	Large Industrial	0.19444	0.09497	0.03691	0.00445	-	-	-	0.04136	**0.33076**
73	ELI 2P-RTP	0.06479	-	0.01057	-	-	-	-	0.01057	**0.07536**
74	Municipal	0.49154	0.30178	0.09181	0.00103	-	-	-	0.09284	**0.88616**
75	Unmetered	0.58145	0.60953	0.09881	0.00540	-	-	-	0.10421	**1.29519**
76	Bowater Mersey (AE)	0.05770	-	0.01087	-	-	-	-	0.01087	**0.06858**
77	GRLF.	0.04596	-	0.00721	-	-	-	-	0.00721	**0.05316**
78	W.M. Backup/Top-up	-	-	-	-	-	-	-	-	**-**
79	1P-RTP	-	-	-	-	-	-	-	-	**-**
80		**2014**								
81		**PCR**	**LCFC**	**BA**						**DCRR**
82	**Rate Class**			**PCR**	**LCFC**	**BA**			**Total**	
83						**PCR**	**LCFC**	**Total**		
84	Residential non ETS	0.34212	0.18489	(0.01974)	(0.00110)	(0.00003)	(0.00000)	(0.00003)	(0.02087)	**0.50614**
85	Residential ETS	0.34212	0.18441	(0.01974)	(0.00797)	(0.00003)	0.00025	0.00022	(0.02749)	**0.49904**
86	Small General	0.93144	0.86613	(0.02776)	0.01011	(0.00342)	(0.00057)	(0.00400)	(0.02165)	**1.77592**
87	General Demand	0.47261	0.40500	(0.01249)	0.00755	(0.00217)	(0.00014)	(0.00232)	(0.00726)	**0.87036**
88	Large General	0.85651	0.95457	(0.02225)	0.03112	(0.00349)	(0.00018)	(0.00367)	0.00520	**1.81628**
89	Small Industrial	0.21875	0.09736	(0.00076)	0.00246	(0.00145)	0.00006	(0.00139)	0.00031	**0.31642**
90	Medium Industrial	0.41347	0.40849	(0.02345)	(0.00238)	(0.00007)	(0.00001)	(0.00008)	(0.02592)	**0.79604**
91	Large Industrial	0.22421	0.13034	(0.02882)	(0.00260)	0.00178	(0.00010)	0.00168	(0.02973)	**0.32481**
92	ELI 2P-RTP	0.07471	-	(0.00453)	-	0.00003	-	0.00003	(0.00450)	**0.07021**
93	Municipal	0.56680	0.41700	(0.02294)	0.00637	(0.00088)	0.00002	(0.00086)	(0.01743)	**0.96637**
94	Unmetered	0.67047	0.82290	(0.05943)	(0.03201)	0.00251	(0.00015)	0.00236	(0.08908)	**1.40429**
95	Bowater Mersey (AE)	0.06595	-	(0.00426)	-	0.00006	-	0.00006	(0.00420)	**0.06175**
96	GRLF.	0.05299	-	(0.00200)	-	(0.00019)	-	(0.00019)	(0.00219)	**0.05080**
97	Wholesale Market Backup/Top-up	-	-	-	-	-	-	-	-	**-**
98	1P-RTP	-	-	-	-	-	-	-	-	**-**

Note: DCRR is an acronym for DSM Cost Recovery Rider

Appendix G

DSM Cost Allocation Approach

DSM Cost Allocation Approach

There are 3 kinds of cost benefits resulting from DSM:

1. *System* - Avoided future infrastructure and related costs, reduced fuel costs, and contribution to achieving environmental and emissions restrictions. All customers receive these benefits.

2. *Class* - When customers within a class participate, the whole class benefits by a reduction in their cost of service allocation, even those who do not actively participate.

3. *Participation* - Customers who are able to participate in DSM programs can lower their own electricity usage and therefore their costs.

The recovery of DSM costs from customers should reflect the level of benefit received by customer classes. Those customer classes who receive the most benefit (i.e., in all three categories) would bear the most responsibility to contribute to the costs. A customer class that receives only system benefits would contribute to the costs accordingly despite not directly participating in programs. Given the nature of DSM programs and benefits it is not possible to precisely calculate and allocate costs based upon these various benefits.

Proposed Allocation of DSM Program Costs:

System benefits will be allocated to all customer classes, except for the Mersey System Rate (i.e., Basic Block), in accordance with the COSS methodology reflecting allocation of generation rate base as per the most recent rate case decision.

Once system benefits have been allocated, the remaining costs relate to the class and participant benefits. These costs should be assigned to the class(es) participating in the DSM programs in proportion to amounts invested in each class.

Method:

- Step 1 – Allocate the system benefits to all customer classes, except to the Mersey System Rate (i.e., Basic Block), allocating s x DT, in accordance with the COSS methodology per the most recent rate case decision, where “DT” represents the total approved DSM program costs and “s” represents the percentage of those costs that the parties agree to be system benefits. “S” will be equal to 25%.

- Step 2 – Directly assign to each class 75% (=1-s) of the DSM investment made for customers in that class. In the column 1 of the attached table for example, DSM expenditures for customers in the residential class could be labelled DC_{res}. The cost allocation approach showing allocation of system costs and proportionate participation costs by class for 2010 are shown on the attached table. If Bowater Mersey participates in DSM Programs, Step 2 will apply to the ELI -2P-RTP class (unless Bowater’s resultant demand drops below 42 MW in which case, it will apply to the Additional Energy served under the Mersey Agreement, to the extent below 42 MW).

- Step 3 – Add the amounts from Step 1 and Step 2 to obtain the total amount to be recovered from each class.

- Step 4 - Divide the total amount to be recovered from each class by the anticipated electricity sales for the class to derive the cost recovery surcharge for each class for the year.

- Step 5 – Annually, true up the forecasted participation by customer class based upon actual experience so that class and participation benefits are more accurately allocated to participating classes.

- Illustrative Cost Allocation Calculations for 2010: (see attached table for steps 1-3)

  DT = $22.89 million
  s = 25%
  DC for each separate class is set out in column 1 of the attached table.

  Step 1 – Allocate 25% x $22.89 million = $5.7225 million to all customer classes except the Mersey System Rate

  Step 2 – Directly assign to each class 75% (=1-s) of the DC for each class

  Step 3 – Add the amounts for Step1 and Step 2 to obtain the total amount to be recovered from each class.

Conditions:

- The allocation of costs based on “benefits” in this approach does not create a precedent for future cost allocation methodologies.

- This proposal applies to classes as a whole (not to individual customers). As a contract rate predicated on power production specifically from the Mersey Hydro System, the Mersey System Rate (i.e., Basic Block) is not affected by DSM energy savings. This proviso does not affect the interpretation of the Mersey Agreement as it relates to the Basic Block, Additional Energy or any other matter.

- This proposal applies to total approved DSM program costs. As such, the attached table is illustrative, and final calculations will depend upon the final approved DSM programs and total program costs.

- This approach will be reviewed after three years (i.e., it applies to 2010, 2011 and 2012).

- The UARB should adopt a DSM Cost Recovery Rider that will recover DSM program costs as allocated in the manner described above, including true-up for actual: costs, energy sales and participation levels for each customer.

Illustration of Program Costs allocated to rate classes

COLUMN	A	B	C	D	E	F	G	H
FORMULA							C + E	
	Total Expenditure by Rate class before allocation. (DC) [1]		System Benefit Costs (25% of the total)		Participating Class benefit Costs (75% of the total)		Total Allocated Costs	
	$ Amount	Relative Share	$ Amount	Relative Share	$ Amount	Relative Share	$ Amount	Relative Share
Rate Class								
Residential	$7,722,093	33.7%	$2,330,369	40.7%	$5,791,570	33.7%	$8,121,938	35.5%
Small General	$1,566,313	6.8%	$137,212	2.4%	$1,174,735	6.8%	$1,311,947	5.7%
General Demand	$7,258,663	31.7%	$1,198,002	20.9%	$5,443,997	31.7%	$6,641,999	29.0%
Large General	$2,432,479	10.6%	$187,445	3.3%	$1,824,359	10.6%	$2,011,804	8.8%
Small Industrial	$272,956	1.2%	$112,524	2.0%	$204,717	1.2%	$317,241	1.4%
Medium Industrial	$1,334,208	5.8%	$257,143	4.5%	$1,000,656	5.8%	$1,257,799	5.5%
Large Industrial	$1,098,582	4.8%	$408,879	7.1%	$823,936	4.8%	$1,232,815	5.4%
ELI 2P-RTP	$3	0.0%	$861,097	15.0%	$2	0.0%	$861,099	3.8%
Municipal	$720,723	3.1%	$95,488	1.7%	$540,542	3.1%	$636,030	2.8%
Unmetered	$483,978	2.1%	$63,590	1.1%	$362,983	2.1%	$426,573	1.9%
Bowater Mersey (AE only)	$1	0.0%	$67,519	1.2%	$1	0.0%	$67,520	0.3%
GRLF	$4	0.0%	$3,232	0.1%	$3	0.0%	$3,235	0.0%
Wholesale Market Backup/Top-up	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%
1P-RTP	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%
Total [2]	$22,890,003	100.0%	$5,722,500	100.0%	$17,167,502	100.0%	$22,890,002	100.0%

(1) DC = DSM expenditure by class
(2) DT = DSM Program Total Cost