Demand Side Management Incentives in Canada

Case Studies of
Aquila Networks (FortisBC) and
Enbridge Gas Distribution

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Preface

Over the past 20 years, utility demand side management (DSM) has helped to moderate electrical and gas load growth in Canada. BCHydro and Manitoba Hydro's Power Smart DSM programs have been operating strongly for 15 years, and many other utilities have begun new DSM programs in more recent years.

Very few gas or electric utilities in Canada, however, are regulated in a way that financially rewards them for achieving more efficiency among their customers. This paper describes the Shared Savings DSM Incentive Mechanism, and provides case studies for two Canadian utilities – one gas and one electric – that operate with such an incentive mechanism.

The paper is topical because it comes at a time when Canada's Council of Energy Ministers is discussing energy supply and demand strategies, and many stakeholders are calling for stronger incentives for DSM. It is hoped that the paper will illustrate how DSM incentive mechanisms can encourage energy distribution utilities in all Canadian provinces to play a major role in making Canada's economy more efficient while at the same time meeting regional and international environmental goals.

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Section 1: An Introduction to DSM Incentives

1.1 The Benefits of Energy Efficiency

End-use efficiency has the potential to play a key role in reducing the demand for energy services currently by distributed energy sources such as gas and electricity. By managing energy loads and maximizing the use of efficient technologies, demand for electricity and gas can be tempered and the need for new supply and distribution capacity reduced.

Many of energy efficiency measures and technologies are cost effective at today's energy prices and therefore provide real cost savings to energy users. If the full environmental and social cost of new electricity and gas supply options are taken into account, end-use efficiency is even more cost effective from society's point of view.

End-use energy efficiency provides multiple benefits:

- Financial Benefits — higher efficiency has direct and indirect financial benefits to consumers and society by reducing the need for additional supply and/or distribution facilities, thus lowering customer energy costs, reducing equipment maintenance, creating opportunities for reducing equipment size, and mitigating risks from future price fluctuations.
- Social Benefits — efficiency investments can stimulate economic development and local job opportunities, and improve the competitiveness of industry, energy security, and the quality of living and working conditions.
- Environmental Benefits — higher efficiency reduces both the direct emissions from on-site energy use, and the environmental impacts resulting from fossil fuel and electricity production and transmission.

1.2 Barriers to Energy Efficiency and Their Removal

While it is in consumer's and the public interest to use energy more efficiently, there are several market barriers that prevent energy users and utilities from making otherwise rational investments in efficient technologies and practices. For example, consumers often do not have access to new technologies, or cannot afford the extra cost of these improvements. In addition, utilities delivering electricity and gas often view efficiency in terms of loss of market share. As a result, when trying to meet a growing demand for energy, they tend to think first of new energy supply options.

It has often been left to governments, therefore, to put policies and programs in place that encourage both consumers and energy utilities to undertake energy efficient investments and programs. Table 1 illustrates some of the roles that government, utilities, private sector suppliers and consumers can each play in energy efficiency improvement programs.

TABLE 1: Typical Roles in Energy Efficiency Programs	
Stakeholder	**Roles**
Society (as Represented by Government)	• regulate utilities • set minimum efficiency standards/codes • develop protocols for labeling high efficiency products, • procure technologies to initiate market transformation • coordinate training • financing/revolving funds • assist low income consumers
Utilities	• design and deliver programs • utilize customer knowledge and billing systems • provide financing, and share in the cost of measure if financially viable.
Private Sector Suppliers	• provide energy efficiency services • deliver programs under contract (bidding/standing offers) • provide financing
Energy Users	• undertake energy management training • maximize use of low cost efficiency measures • finance higher cost efficiency measures from savings

Energy efficiency programs focus on reducing an energy user's overall energy requirements, without affecting the level of energy services they receive. An energy efficiency improvement typically results from installing an energy efficiency technology or adopting a more energy efficient practice. It can mean changing equipment use, building design, and management practices in ways that reduce the total cost of energy services over time. Measures that can increase energy efficiency include adding insulation in building walls and roofs, installing high-efficiency lighting, using high-efficiency industrial motors, retrofitting furnaces and hot water tanks, and sealing leaks in walls and around doors and windows to stop drafts and discourage heat losses.

1.3 Demand Side Management (DSM)

Demand side management (DSM) programs consist of the planning, implementing, and monitoring activities of electric and gas utilities designed to encourage consumers to reduce their level and modify their pattern of electricity (or gas) usage.[1] DSM programs typically promote the use of high-efficiency technology and facility design among customers. DSM programs can range from information or training programs that do not provide any actual financial assistance to end users, to financial incentive programs in which all or part of the cost of the efficient technology or design is paid for by the utility.

The costs of DSM programs include the cost of the efficient technology to the customer and the cost to the utility of the policy or program to encourage its use.

The benefits of DSM programs for consumers are reduced energy costs, capital requirements, and capital expenditures. The benefits to utilities include reductions in capital requirements and improve operating costs. When environmental and social costs of energy supply are factored in, DSM provides even further benefits. In sum, DSM

[1] Electronic Industries Alliance (EIA). Hwww.eia.doe.gov/cneaf/electricity/dsm/dsm_sum.htmlH

enhances social benefits and reduces the social costs arising from the provision of energy services. Utilities will normally undertake DSM programs if there are net financial benefits from doing so, or the net benefits are greater than those realized from using energy supply options when energy demand increases.

> Net benefits of a DSM program = Benefits from DSM – Cost of DSM
>
> Where
>
> Benefits from DSM = DSM savings x Avoided cost of new supply
> Cost of DSM = Estimated cost of DSM programming + Cost of efficient technology

The cost effectiveness of DSM can be assessed from several viewpoints — those of customers, utilities and society. Several tests have been developed to measure the costs and benefits to these different stakeholders.

- The Ratepayer Impact Measure (RIM) test measures the impact of a DSM program on customer billing rates due to changes in utility revenues and operating costs.
- The Total Resource Cost (TRC) test measures the net benefits of a DSM program as a resource option based on the supply side benefits and the total costs of the program, including costs to consumers and to utilities.
- The Societal Test is structurally similar to the TRC test, but it attempts to monetize the impact of a DSM program on emission reductions.

More detail on each of these tests is given in Appendix 1.

Use of DSM in the energy sector has evolved significantly over the past 20 years. DSM in energy utilities began as load management initiatives to reduce customer usage at time of peak demand, thereby avoiding supply problems and deferring the need to build new plants. During the 1980s and early 1990s, however, distribution utilities in North America began to design and deliver DSM programs as a service to their customers. Many state and provincial governments in North America also began to see DSM as a way of promoting energy efficiency, thereby helping to reduce the total social cost of providing energy services. Regulatory systems were put in place that required an integrated resource planning (IRP) approach to capacity expansion and tariff setting. This required DSM programs to be considered on an equal footing with supply options. Targeted DSM programs were designed to defer the need for new supply options.

In the mid-1990s, the deregulation of the energy sector and the breaking up of utilities into separate generation and distribution entities had a major impact on DSM. There were fewer incentives for utilities to invest in DSM and large energy users had access to lower-priced power supplies from competing sources. At the same time, however, governments still recognized the value of DSM in meeting environmental and development goals.

Since 1995, there has been a trend back towards the IRP approach with regulators focusing on retail distribution utilities, and using innovative market-based incentives, financing, and regulatory tools to level the playing field between supply and DSM resources.

1.4 Why are DSM Incentives Needed?

As providers of energy to the residential, commercial and industrial sectors, energy utilities have an inherent motive to increase revenues from the generation, transmission and/or distribution of their products. In many instances the total societal benefits accruing from energy-saving expenditures are greater than those from expenditures on new generation. However, utilities do not normally fully capture the benefits of energy efficiency in terms of revenues. Even if in most instances it is optimal for society as a whole to invest in energy efficiency, it is not optimal to do so from the point of view of the energy services provider.[2] Regulators have thus encountered resistance from most utility managers with respect to promoting energy efficiency.

Governments have recognized that, if the market does not encourage energy efficiency, then it is in the public interest to regulate it so that it does. Regulators, with a mandate to direct and evaluate resource plans of energy distribution utilities, have developed DSM mechanisms to decouple revenues from sales, enable utilities to recover the costs of DSM programs, and, as an incentive, allow utilities to share in the savings themselves. These mechanisms are designed to create opportunities for utilities to financially benefit from actions they take to reduce the amount of energy used by customers.

1.5 DSM and Energy Sector Regulation

DSM mechanisms and incentives can be implemented under one of two models currently used to regulate electric and gas utilities in Canada:

- *Rate-of-return (ROR) or cost-of-service (COS)* regulation essentially allows utilities to pass through those costs deemed necessary by the regulatory body to ensure an adequate level of service is provided to end users. New or adjusted costs are added to the rate base each year, and rates are set to allow the utility to make a reasonable rate of return.

  The cost of running DSM programs is one of the costs included each year in the setting of rates. While this is not an incentive to undertake more DSM programming, neither is it a disincentive.

- *Performance-based regulation (PBR)* involves establishing multi-year performance targets for manageable costs and revenues, such as operation and maintenance, wholesale power costs, quality of service, capital investment, and DSM. The aim is to encourage utilities to improve their productivity as well as make a reasonable return. An agreed upon formula can specify the planned annual growth rate of revenues and costs adjusted for inflation and productivity over the PBR period. Rates are adjusted periodically in order to reconcile the actual and allowed levels of revenue.

  PBR reduces micromanaging of utility operations by the regulator while at the same time providing incentives for the utility to do better over time. Targets can

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[2] Kushler, M. and M. Suozzo. 1999. *Regulating Electric Distribution Utilities As If Efficiency Mattered*. Washington, DC: American Council For An Energy-Efficient Economy. See p. 15.

be positive (e.g., increasing the savings achieved through DSM each year) or negative (e.g., reducing O&M costs or the cost of purchased wholesale energy).

PBR can therefore be used as an incentive for utilities to achieve more DSM benefits each year. More importantly, it provides the opportunity for regulators to add other incentives, such as utilities sharing in the savings achieved by their customers as a result of DSM.

More details are provided on the COS and PBR models in Appendix 2.

1.6 Types of DSM Mechanisms

There are a number of ways regulators can ensure utilities undertake DSM programs:

- Integrated Resource Planning (IRP): Requiring that investment decisions are based on full life cycle costs of supply and DSM options, and planning incorporates a least cost IRP approach.

- Cost Recovery: Allowing DSM program costs to be effectively recovered in rate of return and tariff calculations, and amortized over an extended period.

- Revenue Regulation: Eliminating the incentive to increase sales by having a mandatory revenue cap or by de-coupling sales from profits.

- Lost Revenue Adjustment: Allowing some portion of lost revenue to be recovered in the setting of rates.

- Shared Savings Incentives/Penalties: Allowing utilities to share in savings that are achieved. For example, adding an incentive if savings are over and above DSM targets, and applying penalties if the savings targets are not met.

- Environmental Standards: Requiring utilities to meet certain environmental performance standards.

- Quotas: Establishing quotas for the percent of new investment in end-use efficiency or on-site renewable power sources.

- Minimizing Transaction Costs: Requiring that utilities deliver DSM programs through the most effective means.

Regulators' and utilities' experiences with the application of DSM over the past 25 years have increasingly led to convergence on three financial mechanisms that together form an optimal strategy to encourage the cost-effective pursuit of energy efficiency options.

These are
- Recovery of program costs
- Compensation for net lost revenues
- Shared savings incentive mechanisms (SSM), also known as "shareholder incentives"

Used in conjunction, these mechanisms can effectively “decouple” revenues from sales, taking away the requirement to maximize sales in order to increase revenue, and making it financially worthwhile for utilities to undertake DSM programming.

1.6.1 Cost Recovery Mechanisms

Mechanisms that allow the utility to recover the actual amount it spends on DSM programs or activities are designed to eliminate the business incentive to under spend on DSM. These mechanisms assure the utility that it will recover its expenditures pursuant to DSM plans approved by regulators. The utility’s costs for DSM are usually “expensed,” but sometimes they are amortized over several years. Whatever the specific design of the mechanism, interest is charged on under- or over- recoveries. These mechanisms can be applied under either COS or PBR regulation.

1.6.2 Lost Revenue Mechanisms

Because it decreases the amount of energy needed to satisfy a given level of energy service or comfort, DSM reduces the volume of energy sold by the utility. Some portion of the resulting lost revenue is offset by a reduction or avoidance of variable costs (e.g., the cost of fuel for power plants). The portion of lost revenue not offset by variable cost reductions is a direct loss to the utility.

Lost revenue mechanisms allow utilities to recover all of the revenues that they would have recovered had they not promoted sales reductions through energy efficiency. Their principal purpose is to compensate for the fact that utility costs are spread over a smaller sales base as a result of DSM activities. These mechanisms are designed to make DSM a revenue-neutral activity and eliminate the incentive to minimize savings from DSM. This leaves the utility financially indifferent to the level of DSM that is achieved.

The Lost Revenue Adjustment Mechanism (LRAM) is the most common means to compensate for lost revenues and works as follows: In a given year the utility calculates the amount of volume or kWh losses due to its own DSM initiatives. (This must be calculated net of any efficiency trends occurring independently of DSM, since sales losses due to other factors would have been experienced anyway.)

Under either COS or PBR regulation, distribution rates are set by summing all costs, and then dividing by the revenues generated from services (volumes or kWh) delivered. If services delivered go down as a result of DSM activities, all other things being equal, rates will go up so that costs may be recovered. When actual results are available, differences in the lost revenues between forecast and actual DSM savings are recovered through a variance account that the utility can claim from ratepayers. These variance accounts, for approved amounts, are internal record-keeping tools that the company uses to keep track of claims to be recovered from, or refunded to, ratepayers. Lost revenue recovery is thus effected through the same procedure as is used for program cost recovery. As with cost recovery, the LRAM can be applied under COS or PBR regulation.

1.6.3 Shared Savings Incentive Mechanism (SSM) (Shareholder Incentives)

The third basic type of DSM financial mechanism provides rewards to utilities based on the effectiveness of their pursuit of cost-effective or otherwise socially beneficial DSM.

By its nature, energy efficiency cannot increase the utility's total revenues. A shared savings incentive mechanism (SSM) can, however, compensate for this by providing an opportunity for the utility to share in the customer savings that are achieved as a result of the DSM programs.

The basic goal of a DSM SSM is to encourage a utility to achieve more than DSM targets approved by the Regulator (e.g., targets agreed to under the multi-year PBR or annual COS target). This provides utilities with a positive incentive to continue to build and pursue energy efficiency, and also counters business disincentives to DSM by making it a source of revenue and profit. Penalties for underperformance can also be part of an SSM. This creates a business case for sustainable DSM initiatives that promote energy efficiency on an evolving, adaptive, multi-year basis.

An SSM provides the utility with a share of the net benefits from its DSM activities. It sends the signal to maximize resource savings per dollar spent on energy efficiency measures, and provides additional profits to the utility based on demonstrated DSM performance.[3] For example, a percentage of actual DSM net benefits over and above the target level can be allocated to the utility in the form of a positive rate adjustment. Alternatively, a penalty in the form of a reduced rate can be assessed for not meeting targets.

An SSM is best implemented as part of PBR regulation as this provides the framework for multi-year DSM targets. However, they can also be based on annual targets set under COS regulation.

1.7 Example: Applying a DSM SSM under a PBR Framework

Under a PBR framework a DSM SSM might be applied as follows:

i) <u>Agree on DSM Program Requirements</u>
At the beginning of each regulatory period (usually three years), the utility, regulator and other stakeholders, such as major energy users and environmental/consumer groups, agree on two things:

- the net benefit targets that should be achieved from DSM in the first year
- a formula that gradually increases the net benefits that accrue from DSM programming in subsequent years.

As noted above in section 1.2, net benefits from DSM programs are defined as the savings achieved (m^3, GWh, or MW) multiplied by the avoided cost of new supply, minus the cost of achieving the savings, summed in annual increments over the lifetime of the DSM programs. Net benefits of the DSM program are estimated using the TRC to value each GJ, kW, or kWh saved (see Appendix 1). This TRC is approved in a rate setting hearing before the start of the regulatory period.

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[3] Nichols, D. 1999. "Regulatory Incentives for Demand-Side Management" *Review for West Kootenay Power's DSM Incentive Committee*, Final Report.

A typical DSM PBR formula might be

Net benefits that must be achieved in Year 2 = Year 1 benefits x Productivity index – Year 1 costs x Cost of living index

Many utilities will prepare a multi-year DSM business plan to meet the DSM targets for each year (see case studies in sections 2 and 3).

ii) Include Estimated Cost of DSM in Rate Calculation

The estimated cost to the utility of implementing DSM programs during the regulatory period is included in the rate calculation for the period.

iii) Monitor DSM Results

As utilities implement their DSM plan, they undertake comprehensive monitoring and evaluation of program results, and use this information to assess the costs and benefits of the DSM program.

Utilities will use tools such as sectoral sales data analysis, customer bill analysis, and free rider/free driver surveys to estimate the savings that should be assigned to each DSM program. In some cases, third parties will be used to review results.

iv) Estimate the Additional Savings Achieved

At the end of each year in the regulatory period, the actual level of DSM savings is compared to the target level, and the value of these additional benefits or shortfall is calculated, using the same TRC to value each m^3, GWh, or MW saved that was approved in the rate setting hearing before the start of the regulatory period.

Actual program costs are the sum of the program administration costs, program participant costs, net of free riders and free drivers, and the utility's increased supply costs.

Both costs and benefits are evaluated over the life cycle of the program's impacts.

v) Calculate the SSM Incentive

Once the additional net benefits for the preceding period have been estimated, the SSM incentive is then calculated based on the savings achieved. Several different methods of calculation may be used. One method is to provide an incentive equal to a fraction of the additional savings. In some jurisdictions, if the actual net benefits are lower than planned, then a penalty may be assessed. The fractions are determined through negotiation during the setting up of the SSM and adjusted periodically if greater or lesser incentives are deemed necessary.

The incentive or penalty fractions usually vary between 2% and 18% of additional benefits or shortfalls, depending on the sector and the degree to which the planned benefits are exceeded or not met. In some cases penalties are not applied until actual benefits are less than 90 or 95% of targets.

vi) Add SSM Incentive to New Rate Base
The SSM incentive (positive or negative) is then added or subtracted from the rate base for the subsequent year, along with the LRAM, which is based on the actual reductions in sales versus the budgeted volumes, due to the DSM programs. Any unforeseen COS for DSM can also be claimed in the subsequent year.

vii) Repeat the Process Each Year
The process is repeated each year of the DSM plan, after which a new plan is prepared for the next PBR period.

1.8 DSM Incentives in Canada

Two provinces that utilize DSM incentive mechanisms are British Columbia and Ontario:

British Columbia:

Two of BC's utilities, Terasen[4] (gas) and FortisBC (formally Aquila Networks Canada,[5] electric), are currently operating under a PBR that includes DSM financial mechanisms and incentives. Targets are set for DSM savings and, if the utility exceeds these targets, it receives credit for a percent of total savings in its next rate decision. Both utilities are allowed to amortize DSM program costs over a multi-year period that provides a further incentive to operate DSM programs. Terasen also has a revenue stabilization adjustment that prevents the utility from benefiting from increased sales in the residential and commercial (but not industrial) sectors.

BC Hydro is currently under a rate freeze, and is therefore not yet operating under a PBR. The BC Utilities Commission (BCUC) is now holding hearings on the future regulatory regime for BC Hydro. BCUC published new resource planning guidelines in December 2003, requiring all utilities to file periodic resource plans that consider full social and environmental costs (i.e., an IRP approach).[6]

This paper provides a more detailed look at the DSM incentive regimes used by Enbridge Gas Distribution and FortisBC.

Ontario:

The Ontario Energy Board (OEB) Act of 1998 makes energy efficiency one of the prime objectives of utility regulation in Ontario.[7] DSM mechanisms have so far only been applied to the gas utilities in Ontario. Recovery of program costs and lost revenue adjustments have been approved by the OEB for both of the province's gas utilities — Enbridge Gas Distribution[8] and Union Gas.

[4] Formally BC Gas.
[5] Fortis acquired Aquila Networks Canada in April 2004. Aquila Networks was previously called West Kootenay Power and Utilicorp Networks.
[6] British Columbia Utilities Commission. 2003. *Resource Planning Guidelines*.
[7] The Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Schedule B, states that the board's objectives with regard to gas include, "To promote energy conservation and energy efficiency in a manner consistent with the policies of the Government of Ontario."
[8] Formally Consumer Gas and Enbridge Consumers Gas.

A shared savings DSM incentive has so far been applied only within Enbridge Gas Distribution.[9] Targets for energy efficiency are set, and a shared savings agreement is used to provide incentives to exceed these targets. When Enbridge applies for a rate adjustment, incentive amounts are applied if the target is surpassed. Targets and incentives are set by negotiation between the utility and stakeholders and are approved by the OEB. Enbridge is currently operating under a COS regulatory environment so that DSM targets are negotiated each year.

Discussions are underway as to how the shared savings approach could be used to encourage all Ontario's gas and electric utilities to participate in DSM. Enbridge and Union are exploring opportunities for improving incentive mechanisms, consultation, and audit processes. In electricity, discussions will soon be underway to explore ways to reduce disincentives to distributor demand management.

[9] *Decision with Reasons — Application by the Consumers Gas Company Ltd*. April 22, 1999

Section 2: Case Study — FortisBC (Aquila Networks Canada)

2.1 Background and Regulatory Framework

FortisBC is an investor-owned utility that provides electricity to the southern interior of British Columbia, directly and indirectly serving approximately 140,000 customers. Fortis Inc. acquired Aquila Networks Canada and renamed it FortisBC in early 2004 from Aquila Inc. The utility was formerly called Utilicorp Networks, and before that West Kootenay Power — one of the oldest independent utilities in Canada.

FortisBC has four hydroelectric generating plants with a combined capacity of 205 MW and 10,000 km of transmission and distribution power lines. The utility is regulated by the British Columbia Utilities Commission (BCUC) under a performance based regulation (PBR) established with Aquila in 1997. BCUC has a mandate to ensure that utility expenditures and associated rate changes are in the public interest. Rates are set on an annual basis under PBR using a public “negotiated settlement” process.

In 1995, the regulatory framework for Aquila Networks moved from cost of service (COS) to PBR (see Appendix 2 for more detail on these two frameworks). The first PBR planning period was for three years, from 1996 to1999. The second PBR period was initially set to extend from 2000 to 2002. This is still being negotiated. In the mean time, the original PBR was extended first to 2000) and then another year (to 2001).

The Aquila PBR inherited by Fortis BC includes three incentive mechanisms that allow the utility to benefit from improved performance:

1) If the utility reduces operation and maintenance costs below planned levels, the next year’s rate is reduced, but not as much as if all the operation and maintenance savings were rate based.
2) If the utility power purchase costs are lower than planned, the next year’s rate is reduced but not as much as if all the power purchase savings were rate based.
3) If the utility exceeds DSM net benefit targets, the next year’s rate is increased under a shared savings mechanism.

The PBR DSM targets are set as described in section 1.6 above. DSM benefits targets for each year are based on the 2000 benefits target plus a 3% productivity factor for each of 2001, 2002, and 2003. The DSM cost targets are based on the 2000 cost target plus a BC Consumers Price Index adjustment of 1.9% for each of 2001 and 2002, and 2.34% for 2003. These targets form the basis for the application of incentives or penalties (see section 2.4 below). For incentive purposes the utility’s DSM expenditures are capped at 110% of the target expenditure for program delivery. Planning and evaluation expenditures do not form part of the incentive calculation.

Table 2 shows the FortisBC/Aquila PBR DSM targets for 2004.

TABLE 2: Target Net Benefits 2004 (with maximum and minimum values of +/- 50% of plan)

Sector	Net Benefits ($000)	Minimum	Maximum
Residential	*$374*	*$187*	*$561*
General Service	*$1294*	*$647*	*$1941*
Industrial	*$249*	*$125*	*$374*
	$1917	*$959*	*$2876*

2.2 The History of DSM Incentives at Aquila

The DSM incentives negotiated with Aquila include a shared savings incentive mechanism (SSM), complete approved DSM cost recovery, and lost revenue recovery. The DSM planning process and incentives are discussed in more detail below, in sections 2.3 and 2.4.

Energy efficiency incentives at Aquila date back to 1989 when the company received permission to rate base DSM expenditures, provided the expenditures passed the Total Resource Cost (TRC) test. Revenue requirements for energy efficiency capital expenditures were filed with the BCUC based on planned levels; actual levels were then reconciled in the following year's rate application. In 1991 the BCUC mandated an extension of DSM activities that could be included in the revenue requirement, allowing targeted initiatives among FortisBC's wholesale power customers, which at the time was about 45,000 — half of its total customer base.

When the regulatory framework moved from COS to PBR in 1995 an additional DSM incentive was introduced that involved trying to achieve a lower cost per kWh than had been planned. For each service sector, a target total cost per kWh saved was determined; if the utility managed to bring about the targeted savings at less cost, the difference was shared equally among the utility's shareholders and its customers. For example, if the projected cost to achieve 20 GWh of electricity savings was $2 million, and the utility managed to achieve those savings at a cost of $1.5 million, the utility received half of the $500,000 difference by claiming the outstanding balance in its rates as an additional revenue requirement. Consumers received the remaining amount in the form of lower electricity bills brought about by the energy efficiency savings.

Initially this new targeted-saving incentive was skewed toward large industrial customers, where considerable variable cost reductions in attainable electricity savings were realized. However, stakeholder groups raised some objections to these large cost awards given to the utility in the first couple of years. There was pressure from stakeholders to move towards DSM initiatives targeted at the residential sector, and bring about a more equitable distribution of DSM programs among customer classes.

In 1997 and 1998 new DSM delivery options were considered, and in 1999 an SSM was put in place.[10] This effectively shifted the focus of DSM at Aquila from lowering costs to increasing net benefits.

[10] The SSM was adopted on the basis of recommendations in a report for the DSM Incentive Committee, Tellus Institute. 1999. *Regulatory Incentives for Demand-Side Management — Review for West Kootenay Power's DSM Incentive Committee*, Final Report.

2.3 The Aquila DSM Planning Process

DSM planning at Aquila has been on the basis of a multi-year program. Every year Aquila came forward with a DSM budget that is approved during the negotiated rate settlement process. The objective was to develop a DSM business plan that reflects the market potential in light of available cost-effective technologies and current economic conditions. The DSM plans for the general service and industrial sectors were based on a market potential review conducted for Aquila by Marbek Resource Consultants in the 1990s, updated with new information. The annual savings estimates were determined from “market potential reviews” conducted internally by Aquila that estimated end-use energy intensities. For the residential sector information from BC Hydro’s southern interior region was used, and discussions with their larger industrial and general service customers served as the update basis. The DSM savings potential from each program was established by estimating the effect on energy intensities of replacing stock with available technologies.

Actual DSM performance is monitored on the basis of actual participation levels and established savings values in engineering studies, which are periodically updated with customer billing reviews and surveys. Free riders are considered in the program evaluation process, but are excluded form the annual plans. Free ridership rates are incorporated in the evaluation results on the basis of surveys and commonly accepted rates in similar programs in other jurisdictions. Actual sales volumes are then broken down to different end users to determine savings per sector.

Aquila has also established an “energy management committee” (EMC) process for its larger customers. The purpose of the EMC is to help these customers consider and include energy efficiency as an integral part of their long-term capital plans. This information also gets incorporated into the DSM planning process. The utility hopes to eventually have 70 customers with separate EMCs. Thus far there are 30 active committees.

To assist it with DSM planning and to provide independent scrutiny of DSM performance, a DSM Incentive Committee was established by Aquila in 1996. The committee has representation from eight stakeholder groups, including representatives from municipalities in south-central BC, such as Kelowna and Penticton, Princeton Light and Power, the BC Public Interest Advocacy Center (BCPIAC), the Kootenay-Okanagan Electric Consumers Association, and one member each from Aquila and the BCUC. The committee’s role is to review and comment on annual DSM activities and results and to approve the DSM incentive amount based on the company’s performance. The committee meets one to three times per year and attends at the company’s Annual Review where the PBR negotiated settlement process takes place.

Any issues the committee wishes to raise are discussed, and the utility and the committee work together to try to resolve any issues regarding DSM budgets, programs, and results. Once there is agreement as to actual DSM performance for the previous year and the planned DSM performance and budgets for the upcoming year, the recommendations are forwarded for ratification in the negotiated settlement process. When a formal settlement agreement is reached it must be approved by the BCUC. Any issues that cannot be resolved must go to a settlement hearing at the BCUC. However, it is in the interest of both parties to come to an agreement since hearings are time-consuming and costly in lawyers' fees.

In its DSM planning role, the DSM Incentive Committee also makes suggestions for innovations or strategic considerations. It is not a regulatory requirement to have annual DSM plans approved by the committee, but the utility takes what the committee says seriously, and when recommendations are made the company tries to act upon them. For example, in 2002 it was agreed that the DSM Incentive Committee would contract out a review of North American DSM experience and evaluation of options for new DSM programs in the utility's territory. This report was completed in 2003 and will provide the basis for future DSM plans.

In the 2003 fiscal year the DSM Incentive Committee expressed some concern when the redrafting of a new PBR was postponed for two years. DSM targets are still being based on 2000 benefits and costs adjusted for cost and productivity changes. There is a need to "re-base" DSM targets to put them more in line with actual market conditions.

2.4 The Current Aquila/FortisBC DSM Mechanisms and Incentives

Program Cost Recovery:

Once agreement on planned DSM expenditures has been reached at the negotiated settlement process, a total revenue requirement value for DSM is calculated and these revenues are included in the new rate base. All of Aquila's DSM is funded through this revenue requirement. At present, Aquila spends approximately 1% of gross revenue on DSM expenditures. Annual expenditures are added to the outstanding balance of accumulated DSM costs. These costs are amortised over eight years, and the company earns a normal rate of return on the unamortised balance.

Lost Revenue Adjustment Mechanism (LRAM):

Aquila can recover lost revenue from sales reductions due to DSM, as follows: Lost revenues are estimated by preparing annual sectoral forecasts projecting the decreases in sales brought about by the DSM programs. These revenue losses are estimated net of any avoided variable costs from energy they must purchase from BC Hydro.[11] The lost revenues are incorporated in the utility's total sales forecast for the upcoming year. To determine its rate charged per kWh, total costs plus return on investment are divided by projected sales. Thus the rate charged (and thus the revenue requirement) increases when DSM is factored in, because projected sales in the denominator will fall and increase the rate to be charged.

For example, if forecasted sales without DSM are 3000 GWh, and DSM is forecast to reduce this by 20 GWh, the forecast net of DSM is 2980, and the revenue required to cover the utility's costs will increase — in this respect it is the same procedure as that outlined in section 1.5.2 above. However, if the utility's actual DSM losses turn out to be above or below the forecast, the utility does not recover or pay for the rate difference in subsequent years (i.e., there is no variance account).

[11] The avoided variable cost is based on BC Hydro's rate 3808 — a rate category that has been frozen since 1993.

Shared Savings Incentive Mechanism (SSM):

The shared savings incentive mechanism (SSM) at Aquila, adopted in 1999, provides the company with a share of the net benefits from DSM. As described in section 1.6 above, net benefits are defined as program benefits minus program costs. [12]

Program benefits are defined as the value of avoided energy and capacity costs (deferred capital expenditures) (i.e.,) the same benefits included in Total Resource Cost Test (see Appendix 1). The present avoided cost at Aquila is valued at 2.6 cents for each kWh of energy savings, $29.68 for each annual kW of capacity savings, and $36 for each annual kW saved from peak (deferred capital expenditures). The benefits from DSM programs are estimated over the lifetimes of the DSM measures put in place, which are typically between 5 and 20 years. The benefit values (avoided costs) have remained the same since 1999, however they may change soon as a new DSM planning period is set to begin for the 2005 fiscal year.

Program costs are defined as all utility DSM program costs and the customer costs of energy efficiency.

Every year the utility receives a share of the net present value of the net benefits from DSM in the form of an adjustment to the new standard rate during the negotiated settlement process. Different incentives or penalties are assessed based on FortisBC's actual performance in each customer sector — residential, general service, and industrial. The incentive allocations are presented in Table 3 below. Incentives for the sectors are calculated for performances of 100% to 150% of the PBR target net benefits. Incentives are only allocated up to and including 150% of target, and any benefits above this threshold are not rewarded with a dollar value. There is no penalty for performance between 90% and 100% of target net benefits for all sectors. The maximum penalty is applied to performances of less than 50% of target net benefits.

TABLE 3: Aquila/FortisBC Incentives (+) or Penalties (-) at Selected Performance

% of PBR Target Net Benefits	<50%	<70%	<90%	90-100%	>100%	>110%	>120%
Residential	-6.0%	-4.5%	-3.0%	0.0%	3.0%	4.5%	6.0%
General Service	-4.0%	-3.0%	-2.0%	0.0%	2.0%	3.0%	4.0%
Industrial	-3.0%	-2.0%	-1.0%	0.0%	1.0%	2.0%	3.0%

The incentive payouts are then allocated to the utility and go into the same DSM account as DSM program costs and lost revenues. The balances in this account are amortized and recovered from ratepayers in the form of the rate adjustment.

2.5 Results from SSM Incentives 2001-–2003

The results of the application of the SSM incentive are shown in Table 4. The incentive payouts in 2002 and 2003 were larger than in 2001 because more of the DSM savings occurred in the residential sector where percentage incentives are higher.

[12] The basis of these benefit and cost categories for the calculation of net benefits is the Total Resource Cost (TRC) test, as outlined in section 1.3 and Appendix 1.

Table 4: Aquila Networks Shared Savings Results 2001–2003			
	2001	2002	2003
PBR Target DSM Savings (GWh)	12.5	14.1	15.6
Actual DSM Savings (GWh)	16.9	16.3	18.5
PBR Target DSM Net Benefits	$1,744,000	$1,820,000	$1,968,000
Actual DSM Net Benefits	$2,143,000	$2,063,000	$2,301,000
Favourable Variance	$399,000	$243,000	$333,000
DSM SSM Incentives	$28,100	$61,810	$69,240

Although the incentives received were not insignificant, actual rate impacts accruing from DSM incentives during this period were minimal. The other incentives (O&M and power purchases) were much larger. For example, in 2003 rates were actually decreased by 1.8%. While application of the DSM incentive would have increased rates, the adjustments from the other two incentives were both negative (costs were less than target). The net impact from all three incentives was therefore negative.

2.6 The Business Case for Aquila/FortisBC

The addition of the SSM has improved the business case for DSM at Aquila/FortisBC. The process of applying the SSM during the negotiated settlement process is now relatively straightforward, with the DSM Incentive Committee providing the technical input needed to satisfy BCUC PBR requirements.

Current incentive levels are considered adequate by utility staff and not excessive by BCUC. However, utility DSM staff have suggested it would be positive to remove the threshold or cap on DSM incentives currently set at a maximum of 150% of target. In 2002 Aquila/FortisBC exceeded the cap in residential DSM programs but were not rewarded for this increase.

Even though DSM is still a small part of the organization's capital expenditure level, DSM staff feel that the SSM has brought about more involvement and interest in DSM among management than was previously present, because it conveys a bonus return to the company. The SSM has enhanced the focus of DSM programs to not only consider cost control, but also to concentrate on programs that have a higher benefit-to-cost ratio.

Utility staff feel that DSM can be delivered more easily under a PBR framework with an SSM incentive. DSM can be a challenging proposition within a traditional utility because the emphasis is on minimizing costs, including those of DSM. By shifting the focus from costs to DSM benefits the company becomes more aware that expenditures in DSM provide real benefits to customers. Once this reality is accepted, the company can be more innovative, broadening the nature and scope of DSM so that more customers from each sector can participate and benefit from these programs. This creates customer equity and promotes long term DSM program sustainability.

An important lesson learned by the company is to establish a relationship of trust with its stakeholders and use stakeholder input to support initiatives. The PBR process is also stakeholder-driven, and brings together many groups, such as wholesalers, industrial customers, public interest advocacy groups, and people representing small businesses. Thus it is also customer-driven, which can only improve the utility's service to its customers.

Utility staff recommend that other Canadian utilities adopt the SSM as it offers ways to improve customer responsiveness and increase utility productivity.

2.7 The Business Case for Major Users

The City of Kelowna along with four other municipalities (cities of Grand Forks, Nelson, Penticton and District of Summerland) operate their own retail power utilities and all purchase power from FortisBC. Rod Carle, Electrical Utility Manager of the City of Kelowna, intervenes on behalf of the collective of municipalities and at the same time sits on the DSM Incentive Committee. Since 1995, the City of Kelowna has allowed its customers to participate in all of Aquila's DSM programs. The city has saved over 3,785,000 kWh and received over $192,000 in incentives/rebates from the utility. Kelowna believes that the new SSM has motivated the utility to undertake more DSM as compared to when only cost recovery and lost-revenue adjustments were used.

The City of Kelowna and the other four municipalities all feel that the DSM Incentive Committee has made utility staff listen more closely to its customers/stakeholders, who in turn support current utility DSM policies.

Overall the City of Kelowna is happy with the results of its DSM and the achievements brought about by Aquila.

2.8 The Societal Case: British Columbia Utilities Commission

British Columbia Utilities Commission (BCUC) represents public interest in the regulation of utilities in BC. The commission uses the TRC test to assess the costs and benefits of DSM programs proposed by Aquila/FortisBC (see Appendix 1).

Staff at the BCUC do not feel that the SSM process is difficult to implement — especially if the incentive level is modest and requires little negotiation. If the BCUC had to review the results of the evaluation and monitoring at Aquila in more detail to verify the accuracy of savings estimated by contractors this would increase costs and make the process more complex. In the past BCUC has generally accepted Aquila's independent contractor findings.

Willis Energy does some of the monitoring and evaluation reporting and the results have to be approved by the DSM Incentive Committee. The incentives have remained relatively modest making it a simple process overall.

BCUC staff believe that the SSM has been seen as a modest business case improvement by senior utility management, who also seem satisfied with the delegation of much of the work to the DSM Incentive Committee.

Furthermore, staff at the BCUC see some scope for improvement in the application of the SSM. The utility carries out a number of DSM program evaluations in-house, rather than using independent monitoring and evaluation companies such as Willis Energy. It is acknowledged, however, that the more contracting out that is done, the higher the costs.

Overall BCUC staff perceive more potential for significant savings in the commercial and residential sectors. Overall, using the current SSM, the success of DSM to date in bringing about significant new capacity deferrals has been modest. To a large extent BCUC sees this as a wider problem of market transformation in energy efficiency provision services in BC as a whole — both in utilities and independent providers of energy efficiency services. The SSM therefore can play a part in achieving higher efficiency, but is not the only measure required.

2.9 Conclusions

The defining features of Aquila/FortisBC's DSM promotion framework are DSM program cost recovery, some recovery of lost revenue, and an SSM. The SSM involves modest incentive percentages for the surpassing of DSM targets up to a ceiling of 150% of target benefits. SSM payouts are provided in the form of a rate adjustment. There are penalties for performance at less than 90% of DSM targets. SSM incentives are divided into customer classes, and incentive percentages are highest for the residential sector. This is because in the early days of the utility's DSM programming (in the early to mid-1990s), most programs targeted the industrial sector, while the residential sector was largely untapped.

Overall the SSM has improved the business case for Aquila/FortisBC, but the modest incentive payouts are a small portion of total revenue — currently about 1%. All parties agree that the SSM has helped raise interest and acceptability of DSM in the utility and among stakeholders. Total net benefits, measured by the TRC, accruing from DSM from 2001–2003 alone total $6,507,000, based on the annual reviews published by FortisBC and verified by Willis Energy.

There is general agreement among stakeholders on actual DSM program results achieved. However, staff at the BCUC have pointed out that there is room for more scrutiny of results. This would be even more important if incentives were higher.

Given that the SSM payouts are modest, and that Aquila/FortisBC is a relatively small utility, all parties agree that DSM implementation is simple and straightforward, a fact reinforced by the BC Hydro rate freeze that has simplified the "avoided cost" measurement. The process has also been streamlined by the "negotiated settlement" for coming to agreement on DSM targets and budgets.

The DSM committee has created active and positive stakeholder involvement by interested parties. The Energy Management Committee organized by the utility to help large customers plan for efficiency upgrades exemplifies the cooperation that has evolved between the utility and its customers. Major users like the City of Kelowna are happy with the savings they have accrued from reduced electricity payments. However, one important sticking point is the need for a new multi-year PBR plan, which would re-establish new targets for net benefits. In part the delay in re-basing the PBR formula has been due to the utility undergoing ownership changes since 2000, but the DSM committee still feels that more effort should be made to re-base every three years.

A modest concern raised by stakeholders is that there is a potential for much higher DSM savings in the area. Barriers to the widespread adoption of energy efficiency technologies could be overcome by more comprehensive market transformation of DSM programs.

All parties recommend that DSM incentives be used in other jurisdictions, and note that DSM at Aquila/FortisBC has altogether been a win–win situation for the utility and for stakeholders, offering customers reduced bills, enhancing customer-utility relationships, and increasing productivity at the utility.

Section 3: Case Study — Enbridge Gas Distribution

3.1 Background and Regulatory Framework

Enbridge Gas Distribution, formerly Enbridge Consumers Gas, is an investor-owned natural gas distributor serving 1.7 million residential, commercial and industrial customers in South-Eastern Ontario. It is the largest distributor of natural gas in Canada. Enbridge is regulated by the Ontario Energy Board (OEB), which has a mandate to ensure that Ontario's gas and electric utilities set just and reasonable rates for their services.

From 2000 to 2002 Enbridge operated under a limited O&M performance based regulation (PBR) framework. Since 2003 the company has been under cost of service (COS) regulation pending further consideration on a more comprehensive PBR that targets capital as well as O&M costs. The COS regulation regime means that all costs for the upcoming year are estimated by the firm, forwarded for agreement with intervenors and stakeholders through an Alternative Dispute Resolution (ADR) process, then approved by the OEB. Approved costs and expenses are then incorporated into revenue requirements that can then be claimed from ratepayers (See Appendix 2 for more detail on COS and PBR regimes).

The DSM mechanisms at Enbridge include program cost recovery, a DSM variance account, lost revenue adjustment, and a shared savings incentive mechanism (SSM) beyond target levels. DSM program performance and the DSM SSM are based on target net benefits, based on the TRC test, being attained or exceeded (see section 3.4 below). A percentage of the actual net benefits arising from savings above target are rewarded to the utility in the form of a rate adjustment.

The SSM has been applied in the same way since its inception, regardless of whether the utility operates under PBR or COS.

3.2 The History of DSM Incentives at Enbridge

The guiding principles for energy efficiency programs at Enbridge were set out in the OEB's report of the Board E.B.O. 169-III in 1993. The report established guidelines for the implementation of DSM of natural gas in Ontario, covering issues such as cost-effectiveness screening and the monitoring and evaluation of DSM.[13]

EBO 169-III also gave suggestions as to the regulatory treatment of DSM investments. To the degree possible, it suggested that there should be consistency in the regulatory treatment of supply-side and DSM costs, and that the eligible costs of long-term DSM programs (those with a duration of more than one year), including "hardware," longer-term incentive rebates and loans, labour, overhead and administrative costs, should be put forward by the company for addition in the rate base — provided they are approved.[14]

[13] E.B.O. 169-III Report of the Board, July 23,1993.
[14] The rate base is the value of a regulated public utility and its operations as defined by its regulators, and on which the company is allowed to earn a particular rate of return.

Enbridge implemented its first DSM initiatives in its 1995 fiscal year. At this time the enabling mechanisms only included approved DSM cost recovery allowances. The DSM variance account (DSMVA) was established in which any variance between the forecast and actual costs or benefits of a DSM program are recorded for disposition at the utility's next rate case.

Starting in the 1997 fiscal year the OEB approved the addition of a lost revenue adjustment mechanism (LRAM), which permitted Enbridge to capture volumetric-related revenue variances from the DSM Plan. This is justified on the basis that Enbridge would have gained, in that year, the revenue from selling the gas if it had not saved it through improved energy efficiency. In November 1998 the board approved an SSM for Enbridge that was put into effect starting in its1999 fiscal year.

3.3 The Enbridge DSM Planning Process

Because Enbridge is not currently operating under a PBR framework, annual DSM savings targets, and business plans to achieve them, are set by Enbridge in an iterative process with intervenors and stakeholders. In the first stage, on-staff DSM program marketing staff and sales consultants look at the portfolio of ongoing DSM programs and determine the level of program performance on a year-to-year basis. Forecasts of savings in potential new initiatives are also taken into consideration at this stage. These forecasts are then presented in meetings with intervenors or stakeholders, who bring forward their own views and suggestions. If agreement is not reached, the targets are then negotiated through the ADR process sponsored by the OEB. If agreement is still not reached, the issue goes before the OEB in a formal hearing.

DSM stakeholders meet formally with Enbridge as the DSM Consultative Committee, convened in EBO 169-III described above. The DSM Consultative Committee is usually composed of about ten members. Members have included Canadian Manufacturers and Exporters, the Vulnerable Energy Consumers Coalition, the Consumers Association of Canada, Energy Probe Foundation, the Green Energy Coalition, the Heating, Ventilation, and Air Conditioning Contractors Coalition, the Industrial Gas Users Association, the Ontario Association of School Board Officials, and Pollution Probe. The plan goes back and forth between intervenors and Enbridge in an effort to reach agreement.

The last stage is OEB approval. With regard to DSM plans, the board approves the ratemaking implications of investments and expenditures made by the utility to pursue DSM programs.

To facilitate the DSM review, the Board encourages the parties to reach consensus and reduce the scope and number of contentious issues to be dealt with at the hearing. Thus most of the discussions regarding planned DSM savings targets happen outside of formal hearings. If there is no agreement on certain aspects of DSM the OEB will conduct a hearing (within the issues of a current rate case). However the objective is to come to agreement on as many aspects of DSM as possible to save time and money spent in formal board hearings. The aspects of the DSM plan that the committee have agreed upon are normally straightforwardly approved by the OEB — the board wants to avoid micromanaging DSM.

As part of its annual DSM planning process, the company will file a comprehensive monitoring and evaluation plan that sets out the methods of verifying DSM results. At the end of the year the company must file a comprehensive evaluation report. Every year, as required in the settlement agreement that inaugurated the SSM in 1999, the company puts out a call for third party auditors to certify the DSM Evaluation Report.

After data on actual levels of DSM activity have been obtained, Enbridge estimates actual savings for residential customers. Per unit savings estimates are derived from a combination of engineering estimates, load research, billing analysis, end-use metering, and secondary research. Further adjustments are then made for free ridership, persistence, and so on. The savings claims are constantly questioned, re-assessed, and validated. Actual savings are measured on a customized, individual basis for each of the larger industrial projects by highly experienced, trained Energy Solutions Consultants with the assistance of various savings calculation tools and engineering analysis.

More details on how the SSM is applied at Enbridge are provided below.

3.4 Current Enbridge DSM SSM

The SSM at Enbridge is awarded if the actual net benefits of DSM, as estimated by the TRC test, exceed the board-approved DSM target, or “pivot point,” in millions of dollars. This dollar amount will vary from year to year, depending on the DSM targets, the mix of energy savings measures included in the DSM plan, and the costs of the programs. At the end of the year the actual results are screened and verified and the net benefits are calculated. The net benefit, or saving, over and above the pivot point is then determined to be the eligible amount upon which the shared savings incentive will be calculated.

The SSM at Enbridge currently states that the company is eligible to claim SSM when the actual savings valued at the TRC exceed targeted (budgeted) savings:

- first 10% over budget = reward of 18% of savings
- second 10% over budget = reward of 15% of savings
- third 10% over budget = reward of 12% of savings
- fourth 10% over budget = reward of 9% of savings
- in excess of 40% over budget = reward of 6% of savings.

There is no penalty for under-budget DSM performance. In fiscal 2003, Enbridge successfully argued against a penalty, because they didn’t feel it was appropriate. The argument was that DSM programs undertaken at Enbridge bring about many millions of dollars of resource savings to customers even when the target is under-achieved, and extensive consultations with stakeholders as well as pre-program program cost-effectiveness testing ensure an adequate amount of DSM activity by the company. The company feels it has to bear an undue amount of risk if a penalty is in place when actual DSM savings do not reach forecasted levels. The idea is to incent appropriate behaviour, rather than punish less than optimal achievements.

3.5 Results for 2000–2004

Results for Enbridge's DSM programming from 1995 to 2002, including program expenditures, net benefits, and annual gas savings, are presented in Table 5. Results for 2003 and 2004 have not been finalized.

TABLE 5: Enbridge Gas Distribution DSM Program Results, 1995–2002[15]

Fiscal Year	DSM Program Spending (Constant 2003 dollars)	Financial Net Benefits (TRC) (Constant 2003 dollars)	Annual Gas Saved ($10^6 m^3$)	TRC Savings/ O&M Spending
1995	$2,564,082	$5,595,800	3.9	2.18
1996	$3,348,722	$28,021,257	18.8	8.37
1997	$3,337,571	$27,176,074	18.6	8.14
1998	$4,044,945	$62,058,181	36.2	15.34
1999	$7,268,495	$60,929,686	45.7	8.38
2000	$10,097,721	$63,192,936	48.6	6.26
2001	$13,051,140	$83,212,168	68.0	6.38
2002	$11,415,079	$145,300,433	77.6	12.73

Information on Enbridge's DSM targets, results, expenditures and earned SSM incentives is shown in Table 6.

TABLE 6: Enbridge Shared Savings Incentives Results 2000–2003

	2000	2001	2002	2003
DSM Volume Target (million m^3)	42	67.9	92.5	72.5
DSM Savings Achieved (million m^3)	58.8	82.4	92.4	N/A
DSM Expenditures (million $)	9.3	12.4	10.9	10.85 (budget)
DSM SSM Earned (million $)	3.5	4.6	0	N/A

Table 7 presents cost effectiveness results for the DSM programs, provided by Enbridge earlier this year, based on audited results.[16] As shown, the TRC net benefits have been continually increasing over the years, but the benefit-cost ratio has fluctuated.

Table 7: Cost Effectiveness results (1995–2002)

Year	Gas Saved ($10^6 m^3$)	Target Savings ($10^6 m^3$)	Variance (gas savings versus target)	Total Benefits[17] (millions$)	Total Costs (millions$)	TRC Net Benefits (millions$)	Benefit-Cost Ratio
1995	3.9	12.8	-70%	N/A	N/A	4.7	N/A
1996	18.8	29	-35%	N/A	N/A	24	N/A
1997	18.6	47.3	-61%	N/A	N/A	23.8	N/A
1998	36.2	44.6	-19%	72.9	18.1	54.8	4.03
1999	52	31.2	67%	107.1	50	57.1	2.1
2000	58.9	42	40%	98.8	24.2	74.6	4.1
2001	82.4	67.9	21%	210.3	37.8	172.5	5.56
2002	92.4	92.5	0%	219.4	48.4	171.1	4.53

3.6 The Business Case for Enbridge

Enbridge sees the SSM as having put DSM on the same footing as other revenue generating activities at Enbridge. This has allowed for a greater company focus on DSM

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[15] From the OEB's RP-2003-0203 Exhibit L, Tab 11, Schedule 1, prepared by Chris Neme for the Vermont Energy Investment Corporation. Values for 2003 and 2004 are from the post-ADR DSM plans.
[16] Enbridge Gas Distribtion. 2004. *A Recommended Response to the Minister's Directive on DSM/DR for the OEB*.
[17] Total benefits are based on the wholesale cost of the avoided gas and the avoided costs of any associated electricity and water savings over the lifetime of the measures implemented.

and created an awareness of the importance of DSM at all levels of the company. The presence of the SSM has also encouraged the company to focus on programs that generate large volume savings (that are cost-effective from a societal point of view) and also to develop rigorous monitoring and tracking procedures.

The SSM percentage incentive of 18% is making a positive impact on profits and this has increased upper management's interest in DSM. However, DSM still takes up a very small percentage of the company's revenue requirements — approximately 0.3–0.5% of Enbridge's gross revenues.

The DSM planning process has its challenges. There are some parties that would like to see more DSM, while others are concerned about budget impacts. Too much back and forth on the DSM plan could lead to Enbridge having to re-write their DSM plans and budgets multiple times. Evaluation and documentation also takes a lot of time and there is considerable scrutiny by some stakeholders. Disagreements can occur due to the differentials between planned and actual results. An important lesson that has been learned is that "rules of engagement" and calculation methodologies on DSM planning and assessment need to be clear and articulated at the outset.

There is agreement among DSM managers at Enbridge that the process of deriving and coming to agreement on a DSM target and budget, and then coming to agreement on reconciling actual DSM results, could be simplified. For example DSM staff suggest that monetizing the value of each m^3 of gas saved, and then agreeing on the planned and actual levels of gas saved, could save time and money. In this scenario it would take more time upfront to identify an acceptable procedure to monetize the value of gas savings, but in subsequent years the "gas value" formula could be easily updated and the company would only have to apply for deviations from the planned level. This simplification would bring gas DSM incentive mechanisms in line with electricity DSM incentives (like FortisBC) where an avoided cost per kWh saved is used to value DSM savings.

The form of the future SSM is still a subject of discussion between Enbridge and the intervenors.

Enbridge DSM staff also emphasize that a supportive regulatory framework is an essential prerequisite to the development of DSM in a utility context. The framework should include the following:

- recognition that different areas can have different needs and objectives - there's no magic bullet
- appreciation that DSM needs to live where the customers are
- clearly defined requirements, guidelines and success measures
- guidelines regarding selection of DSM programs (offered to all rate classes, cost-effective from a societal point of view)
- financial mechanisms that keep the utility "whole" with respect to DSM (cost recovery and recovery of lost revenue through rates)
- a DSM variance account that provides the utility with additional resources and flexibility to maintain continuity and leverage successful programs from year to year

- a financial incentive mechanism that enables DSM to contribute to the profitability of the utility thereby increasing management focus and driving the appropriate behaviours

3.7 The Business Case for Major Users

The Industrial Gas Users Association (IGUA) is an association of about 45 industrial companies with plants located in Manitoba, Ontario and Québec. Most members are processors of natural resources, including metals companies Alcan and Dofasco, mining companies such as Cameco and Inco, and pulp and paper companies such as Abitibi-Consolidated and Domtar. Its members are large users of natural gas in their manufacturing and processing operations, typically either as a process fuel or feedstock.

The IGUA acknowledges that there is still a significant cost-effective energy-efficiency potential in Ontario that the market will not capture on its own due to market barriers. The SSM increases the DSM activities at Enbridge to overcome these barriers. The team at Enbridge is large enough to provide energy-efficiency measurement assistance to industry and has programs in place where, if needed, they can assist an industry with financing such measures.

One of the IGUA's concerns regarding DSM incentives is that the SSM payments be kept to a reasonable limit, so that industry can also benefit from the savings achieved.[18] This issue is important to the IGUA because of the high gas costs faced by members; prevailing prices range from $4.00 to $4.50, when earlier, in the late 1990s, gas prices averaged $1.50 to $2.00.

3.8 The Societal Case: The Ontario Energy Board

The OEB has provided guiding principles for the management and regulatory treatment of DSM activities by gas distributors. In E.B.O. 169-III, the OEB recommended an iterative screening process for the utilities to follow when developing their DSM portfolios. Cost effectiveness tests suggested in this report include the Societal Cost Test (SCT) and Rate Impact Measure (RIM) test.[19] The recommended screening process for DSM programs provided by the OEB in its report is shown in Figure 1. As shown, programs passing the SCT test but failing the RIM test would have to pass a third test to ensure that any related rate impacts are not excessive, and that indirect costs do not exceed the net benefits of a program. Programs failing the third test would be evaluated once more before being discarded or deferred. In general the OEB suggested that all prospective programs should pass the SCT, but failure to pass the RIM test would not necessarily eliminate a program.

As part of monitoring and evaluation, the OEB also suggested that a utility submit to intervenors an overview of its DSM plan that describes (1) The goals of its DSM portfolio and how these would be achieved; (2) The objectives for resource planning and customer service; (3) Specific DSM savings objectives by class of customer; and (4) A discussion of the alternative implementation strategies considered.

[18] See IGUA president P. Fournier's testimony before the board in RP 2002-0133 Vol. 15, April 15, 2003.
[19] The Societal Cost Test (SCT) is a variant of the Total Resource Cost (TRC) test, the main difference being that monetized environmental externality values are included in the SCT. See Appendix 1.

The OEB is of the opinion that the use of DSM incentives has intensified consultations between Enbridge and stakeholders during and outside the annual gas distribution rate review proceedings. Incentive mechanisms (specifically LRAM and SSM) have increased the sensitivity of stakeholders to monitoring and evaluation, and regulatory reporting of DSM program details and results.

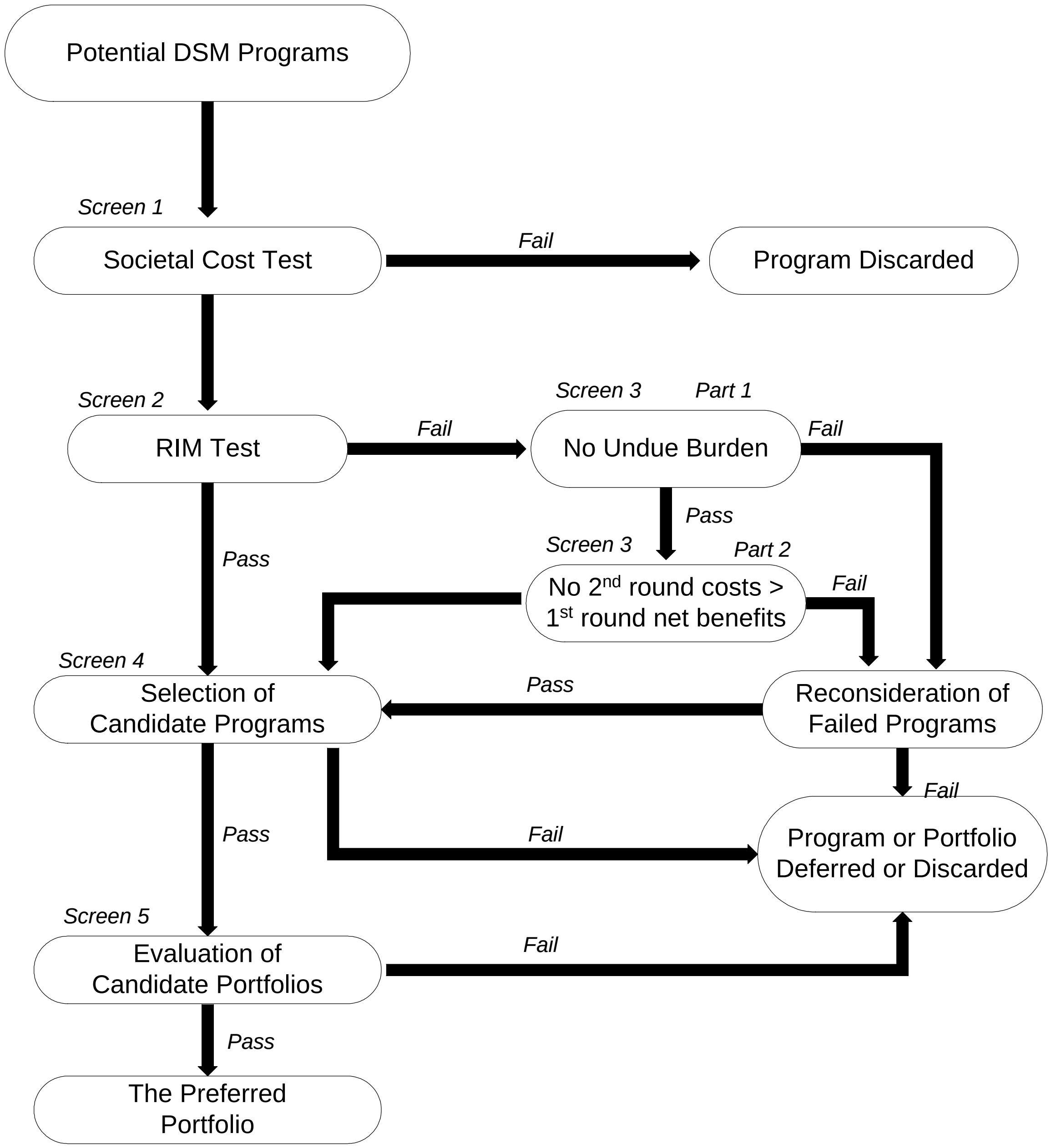
Despite these positive developments, however, the OEB has recently stated that DSM mechanisms for gas utilities in Ontario could be improved.[20] It considers that consistency and clarity are important, and notes that the two gas distribution companies operating in Ontario (Union and Enbridge) have different incentive frameworks. Further, improved regulation of DSM activities is necessary to better manage the regulatory process. Specific areas for improvement could include

- regulatory instruments (including revenue protection and incentives)
- verification (monitoring and evaluation, compliance, and audit)
- commonality (consistency of framework between distributors).

The OEB has stated its intent to review the regulation of DSM activities by gas distributors. In the meantime, it continues to oversee gas DSM in individual rate cases.

[20] See Report of the Board to the Minister of Energy. 2004. *Demand-Side Management and Demand Response in the Ontario Electricity Sector*.

Figure 1: OEB Recommended Screening Process for DSM Programs and Portfolios



3.9 The Societal Case: Environmental and Consumer Interests

Pollution Probe, a member of the DSM Consultative Committee since its inception, believes DSM incentives at other utilities are essential to bring about energy efficiency savings. Few incentives for DSM occur unless there are financial mechanisms, namely the LRAM and SSM, because they create an overall framework to make it profitable for utilities to decrease customers' bills. This is a view echoed by the DSM managers at Enbridge.

Pollution Probe also points out that the DSM committee has played an important role in bringing about over $700 million in customer bill reductions from DSM since 1995. This is partly because stakeholders have a forum, through the ADR, to make sure the utility achieves the highest possible volume savings at the lowest possible budget. Furthermore, the role of the SSM has been important in motivating the utility to meet volume targets. Before the SSM was in place, the utility continually failed to meet its volume target, whereas afterwards it consistently met or exceeded it (see Table 6). In addition to customer bill reductions, Pollution Probe points out that the energy savings brought about by DSM also help increase competitiveness, create new jobs in the energy efficiency industry, reduce smog, and improve Canada's ability to meet Kyoto targets.

Other environmental groups on the DSM committee have pointed out that, although DSM savings have been considerable, there is still a lot of room remaining for market penetration of energy efficient technologies. Chris Neme, on behalf of the Green Energy Coalition (GEC), presenting in an OEB hearing on April 15, 2003, cited a study commissioned by Enbridge showing that the current market share for high-efficiency condensing boilers is only 4 to 7 percent.[21] This view is echoed by Pollution Probe, which points out that energy efficiency opportunities implemented to date are only scratching the surface, and that technological advances can continually create new opportunities. It argues that, as opposed to a lack of technologies, barriers to DSM opportunities occur due to inadequate "market transformation" incentives in the provision of energy efficiency services.

3.10 Conclusions

The current DSM incentive mechanisms at Enbridge Gas Distribution operate on an annual rather than a multi-year basis. This is because the utility operates under a COS rate setting regime pending agreement on PBR (see section 3.1 above). It appears that the SSM and other DSM mechanisms can be implemented equally well under COS as under PBR. However, the PBR framework, if agreed upon and properly designed, could streamline the regulatory process by using multi-year DSM targets.

The Enbridge DSM SSM features between 6 and 18% of DSM savings greater than the DSM targets set by a consensus of stakeholders and approved by the OEB. Incentive percentages start at 18% for DSM benefits greater that 10% over the target, dropping to 6% for any DSM benefits more than 40% over target. The same percentages are

[21] From the OEB's RP 2002-0133 Vol. 15, April 15, 2003. The study is referred to as the "The Jacques Whitford Study."

assigned to all customer classes. No penalties are incurred by the utility for not meeting agreed DSM targets. The incentives totalled $3.3 million in 2000 and $4.6 million in 2001.

In addition Enbridge is provided with a cost recovery allowance and an LRAM.

There is active stakeholder involvement in DSM through a DSM Consultative Committee. Members are committed to ensuring that Enbridge meets a maximum volume target at minimum possible cost. Membership includes major gas users and environmental groups. The consensus process incorporating ADR works well to keep many disputes away from formal hearings. However, stakeholders have raised concerns about the length of time taken up by the regulatory process in dealing with rate application settlements.

Overall, the SSM payouts do increase the business case for the utility. For example, in 2001 SSM revenue totalled $4.6 million. However, at 0.3–0.5% of gross revenues, this is still a small fraction of total revenues at Enbridge. This fact may ultimately temper the size and type of DSM measures implemented at the utility, particularly as newer efficient gas technologies may involve increased investment risk.

All stakeholders agree that the incentive mechanism has raised awareness of and support for DSM programming and efficiency among energy users and regulators. The utility, OEB and most stakeholders also agree that the SSM incentive approach would be worthwhile to apply to other utilities.

Some industrial stakeholders on the committee who are major gas users have expressed concern that the incentive percentages are too high, and provide fewer incentives on the user side (penalizing their efficiency efforts). Coupled with the recent rising price of gas, earned incentives will become even higher. The rise in gas prices inevitably raises the value of avoided cost of new gas supply in the TRC, and thus total net benefits of DSM are higher. However, environmental interests on the committee are still happy with DSM SSM results at Enbridge, and have cited the important benefits that continually increasing gas savings levels have brought about (see Tables 4 and 6). Another point of contention is the cost of redrafting the DSM business plan and targets multiple times as a consensus is reached among stakeholders. This would be lessened if a multi-year PBR approach were used.

There are some difficulties in finding third parties to verify the DSM savings achieved every year, and in the past Enbridge has had to go to the US to find DSM auditors.

There have been proposals by both the utility and stakeholders for streamlining and improving the DSM incentive process. Enbridge has recommended that valuing gas savings per unit of energy (like electricity) could streamline the process further.

Section 4: Comparative Analysis of DSM Incentives

This section provides a comparative analysis of the DSM incentive mechanisms applied at Aquila/FortisBC and Enbridge. The similarities and differences between the DSM incentives themselves are described, as well as the ways they are applied, and the participation and views of stakeholders. Finally, the application of incentives in gas versus electricity distribution is addressed, as well as the use of DSM incentives in monopoly or competitive distribution markets.

4.1 Regulatory Framework

The experience at both Aquila/FortisBC and Enbridge has shown that the application of DSM programming and SSM incentives is similar, regardless of whether the regulatory framework is performance based regulation (PBR) or cost of service (COS). The major difference is that under PBR (at Aquila/FortisBC), multi-year DSM targets are set, while under COS (at Enbridge) targets are set annually.

Both Aquila/FortisBC and Enbridge use three DSM mechanisms — DSM program cost recovery, a lost revenue adjustment mechanism (LRAM), and a shared savings incentive mechanism (SSM).

Transaction costs of DSM incentives are lower if implemented under PBR because targets are set each year by application of a formula agreed to by utility and stakeholders at the beginning of the, typically three-year, PBR period. This provides cost savings as targets do not have to be agreed upon every year as they do under COS.

This explains the considerable number of concerns expressed in Ontario about the time it takes to apply SSM incentives (using COS at Enbridge) as compared to the far fewer concerns expressed in BC (using PBR at Aquila/FortisBC since 2000). The good stakeholder-utility relationship at Aquila/FortisBC, the smaller SSM incentive percentages, and the stable avoided cost calculation are also factors that may make the Aquila/FortisBC DSM incentive process less costly and controversial.

4.2 Size of Incentive Percentage

The larger the incentive percentage, the more savings are provided to the utility in the form of a higher rate. This, of course, lowers the benefits to participating energy users. The optimum percentage would provide a high enough incentive to the utility to improve its business case, while not penalizing energy users.

The percentages used at Aquila/FortisBC appear quite low. They are not low enough to make the incentive mechanism cease to be worthwhile, but probably low enough to leave potential savings untapped. At Enbridge, the percentages appear to be too high for some large industrial and residential gas users who feel they are unfairly penalized — especially as gas prices rise. A compromise in the 10–12% range might be optimal. The percentage could be varied among sectors depending where the largest untapped savings exists. The avoided cost of electricity and gas would also need to be taken into account, as energy users would want a higher share of savings in an increasing price environment.

Higher percentages also mean that more stringent verification of savings is demanded by stakeholders, which increases the transaction costs of the DSM incentive.

Aquila/FortisBC operates under an SSM with a penalty for not meeting targets, and also has different reward and penalty levels for each major user sector — industrial, commercial, and residential. Enbridge has one incentive regime for all sectors and no penalty. Both utilities have increasing percentages for increased DSM savings over targets with a cap beyond which rewards are not provided. There is some basis for Enbridge's argument that incentives should only reward success and not penalize failure because any DSM brings about benefits. However, this is only reasonable if DSM targets are met most years. Each utility has only failed to meet its target once in the past five years.

The additional flexibility of the Aquila/FortisBC system is well liked by the utility and stakeholders as it allows fine-tuning of incentives depending on where the greatest DSM potential lies. However, British Columbia Utilities Commission (BCUC) is not supportive of changing incentive percentages on an annual basis.

4.3 Avoided Cost

Both utilities use the total resource cost (TRC) to value benefits from DSM. There appears to be support for this approach among all stakeholders as it measures DSM on a level playing field with the cost of new supply. Here there is one difference between the two utilities: At Aquila/FortisBC DSM savings targets and actual savings are set and measured in kWh/year and avoided cost in $/kWh is used. At Enbridge targets are set in $/year. Enbridge has suggested using volumetric savings (m^3/year) and an avoided cost per m^3 to simplify the current process in Ontario.

4.4 Target Setting and Verification of Savings

Both Aquila/FortisBC and Enbridge utilize stakeholder committees to administer their SSM. Both committees involve major energy users and environmental and consumer groups, as well as the utility itself and the provincial regulator. The committees carry out several important roles, including

- providing advice on DSM programming and (in the case of Aquila/FortisBC) undertaking long-term DSM planning and evaluation reviews
- setting annual DSM targets or PBR multi-year DSM targets on consensus basis
- evaluating savings reports
- overseeing the application of the SSM incentive formula
- recommending targets and incentives to the regulator.

All of these roles reduce the time taken during the annual regulatory hearings when the DSM incentive is applied to the rate base. In Ontario the consensus process is called an Alternative Dispute Resolution (ADR) process. While some stakeholders feel the process is too long, regulators in both Ontario and BC are pleased that these deliberations occur outside the official hearings (see section 4.7 below).

Verification of actual DSM program savings can be a time-consuming process, and it can be difficult to find acceptable independent auditors. Enbridge had to retain US auditors to verify savings to the satisfaction of all stakeholders. Aquila/FortisBC, on the other hand, carries out its own DSM program monitoring or uses a BC consultant (Willis Energy) that also serves as technical support to the DSM Incentive Committee. This approach to verification appears to have the confidence of the committee.

4.5 The Business Case

Both Aquila/FortisBC and Enbridge view the DSM incentive mechanism as having a positive effect on its revenue, therefore improving its business case. DSM is now seen as “good for business” by upper management. This is due more to the DSM incentive framework itself than the actual revenue, as in both cases the additional revenue from DSM is less than 1% of total revenue. This is an important conclusion, as it means that incentive percentage levels can be set on the basis of fair share between utility and user rather than the size of the actual revenue.

It also means that DSM incentives can be applied to both small utilities like Aquila/FortisBC and large utilities like Enbridge. The framework and reward system provide the right business environment for DSM irrespective of the financial resources that the utility might have to invest in DSM. This is important when considering extending DSM incentives in provinces like Ontario that have a large number of small utilities. Aquila/FortisBC feels that the DSM framework they use would be acceptable and beneficial to other utilities. Enbridge has stated that smaller electric utilities in Ontario could also use DSM incentive mechanisms within their service territories, and be able to contract out the design, delivery, implementation and evaluation of DSM programs if they do not have the capacity to deliver them.[22]

Economies of scale and the size of the utility as well as the regulatory structure (competition versus non-competition, see below) will have an effect on the level of risk, and thus the types of DSM programs that can and will be implemented by a utility. As a matter of policy and fairness, utilities should bear only “normal” business risk — that is, their reward should be contingent upon effective program management.

4.6 Other Stakeholders

Most stakeholders on Aquila/FortisBC and Enbridge DSM incentive committees, both energy user and environmental/consumer groups, agree that their DSM SSM incentive mechanisms have raised interest and acceptability for DSM within utilities and among energy users.

Both sets of stakeholders also say there is a lot more DSM potential that can be achieved in their respective areas, and that SSM incentives could play a major role in achieving them by encouraging utilities to take part in more comprehensive and expensive “market transformation” programs coordinated by federal or provincial governments.

[22] See *Principles and Frameworks for DSM in Ontario: A Policy Paper by Enbridge Gas Distribution*, November 17, 2003.

4.7 Regulatory Bodies/Provincial Government

The provincial bodies in BC and Ontario regulating Aquila/FortisBC and Enbridge see their respective DSM incentive mechanisms as being in the public interest and raising the level of DSM activity and general interest in DSM. While both BCUC and the OEB suggest improvements in the application of the SSM incentives, they both appear relatively happy with the process and the fact that, in most cases, the utility brings targets and verified savings to rate hearings already accepted by all stakeholders.

In both BC and Ontario, the incentive mechanisms were negotiated between the utility and regulator without involvement of the province. The provincial legislation governing the regulators provides the effective enabling conditions for the use of DSM incentives.

In both BC and Ontario, however, new governments have recently made some changes that could affect these enabling conditions. The new BCUC resource planning guidelines[23] require that all utilities (including BC Hydro) submit a multi-year integrated resource plan treating supply and demand resources on an equal basis. Hearings are currently being held to determine how rates will be regulated at BC Hydro. The impact of these changes on the current FortisBC PBR and DSM incentives are not yet known.

In Ontario, the new government has tabled new legislation governing the power sector. Its impact on DSM incentive mechanisms at gas utilities like Enbridge is as yet unknown.

Both FortisBC and Enbridge currently operate in markets without retail competition. Their experience, therefore, cannot be used to compare the way that DSM incentive mechanisms would operate in a competitive market environment. Some observations can be made, however. Volumetric savings targets and SSM for gas (m^3) and electricity (kWh) could be used just as easily in a competitive retail market such as in Alberta. If a utility lost market share to a competitor, higher efficiency levels would be required to meet or exceed DSM targets. Conversely, increased market share would make it easier to exceed targets.

There do not appear to be many differences between Aquila/FortisBC and Enbridge that could be linked directly to the fact that one distributes electricity, the other natural gas. In the case of a gas utility like Enbridge, the avoided cost of new supply is dependent only on the wholesale price of gas (as long as new pipeline capacity is not needed). For Aquila/FortisBC, the avoided cost includes both consumption (kWh) and capacity (MW) terms and therefore the application of the DSM incentive is slightly more complex.

The only other difference might relate to the complexity of the gas and electric DSM markets themselves. Gas DSM markets involve fewer end uses and technologies, and therefore the potential savings are easier to identify. However, the savings may be more difficult to obtain beyond conventional efficient technologies. This may explain the higher incentive percentages at Enbridge to reflect the higher risk.

[23] British Columbia Utilities Commission. 2003. *Resource Planning Guidelines.*

Appendix 1: DSM Cost Effectiveness Tests

Demand side management (DSM) cost effectiveness tests are used to compare the costs and benefits of DSM programs and to estimate the unit cost of energy savings from using the program. Two of these tests are the Total Resource Cost (TRC) test and the Ratepayers Impact Measure (RIM) test.

Total Resource Cost Test[24]

The Total Resource Cost (TRC) test is used to evaluate DSM programs from society's point of view. As such, it looks at the net benefits to society, allowing costs to one group of stakeholders to be cancelled out by benefits to others. The TRC is a measure of change in cost of service across all customers as a result of the DSM program. The TRC is therefore a screening tool used when the broader public interest is being considered. It allows a DSM program to be compared as a "resource" against energy supply options.

The costs of the DSM program used in the TRC test include

- costs to program participants (normally the additional cost of the efficient technology
- the costs to the utility of running the program

The benefits used in the TRC test are the avoided supply costs over the life of the efficiency measure (this is usually longer than the length of the DSM program). The avoided supply costs are the marginal transmission, distribution, generation, and capacity costs for the periods when there is an impact from the efficiency measure.

Both costs and benefits are expressed in Net Present Value (NPV), and the net cost or benefit calculated. If benefits exceed costs, the program is beneficial from societal view. The TRC can also be expressed as a benefit–cost ratio, where a ratio >1 shows a benefit to society. Finally if the NPV costs are annualized over the life of the efficient measure and divided by the annual savings in kWh or GJ, the levelized cost in cents per kWh or GJ can be determined to compare against supply options.

As noted above, the costs in the TRC test are the program and technology costs paid by both the utility and the participants. This includes all equipment costs, installation, operation and maintenance, cost of removal (less salvage value), and administration costs, regardless of who pays for them. For example, while a government or utility may provide a sales tax rebate for a residential appliance, this will not affect the TRC as the total cost of the program to society has not changed

A variant on the TRC test is the Societal Test. This test is structurally similar to the TRC test, but it attempts to quantify the change in the total resource costs to society as a whole rather than to only the service territory (the utility and its ratepayers). The societal test differs from the TRC test in that it includes the effects of environmental externalities, excludes tax credit benefits, and uses a different societal discount rate. Many economists have pointed out that use of a market discount rate in social cost-benefit analysis undervalues the interests of future generations. In order to correct for this the societal test a lower discount rate than in the TRC. Marginal costs used in the Societal

[24] The California Public Utilities Commission (CPUC) developed the tests discussed. See CPUC. 2001. California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.

Test would contain externality costs of power generation not captured by the market system. These external costs include environmental damage caused by electricity or natural gas use, including that from sulphur oxides, nitrogen oxides, volatile organic compounds, small particulate matter, and carbon. Other externalities can include avoided transmission and distribution costs, and the benefit of increased system reliability.

Ratepayer Impact Measure (RIM) Test

The Ratepayer Impact Measure (RIM) test measures what happens to customer bill or rates due to changes in utility revenues and operating costs as a result of a DSM program. Rates will go down if the change in revenues from the program is greater than the change in utility costs. Conversely, rates or bills will go up if revenues collected after the program implementation are less than the total costs incurred by the utility in implementing the program. This test thus indicates the direction and magnitude of the expected change in customer bills or rate levels.

The costs used in the RIM test include

- costs to the utility of the running the program including initial and annual administrative costs, additional operation and maintenance, installation (if paid for by the utility), and customer dropout.
- share of the cost of the efficiency measure paid by the utility (if any)
- revenue lost by the utility as a result of the program over the life of the efficiency measure

The benefits used in the RIM test are the same avoided supply costs used in the TRC test, above. The avoided supply costs are marginal transmission, distribution, generation, and capacity costs for the periods when there is an impact from the efficiency measure (i.e., the life of the efficiency measure).

The primary measure used in the RIM test is the NPV of the benefits minus costs. A net benefit shows that utility revenue is increased, and therefore customer rates can be reduced. The RIM test can also provide a measure of the net change in revenue per kWh or GJ saved, a utility benefit–cost ratio, and rate impacts on individual customer classes.

Appendix 2: Utility Regulation Frameworks

Rate of Return (ROR) or Cost of Service (COS)

This approach is basically a procedure whereby approved revenue requirements are added to the rate base. Rate of Return (ROR) regulation is also called Cost of Service (COS) regulation in that it essentially allows companies to pass through those costs deemed necessary by the regulatory body to ensure that an adequate level of service is provided to end users. During periodic regulatory reviews, expenditures deemed appropriate by the regulator are added to the rate base. To ensure that appropriate levels of capital investment are undertaken, appropriate rates of return are calculated for the regulated utility, based in part on the cost of capital to the utility.

COS regulation has both its virtues and its weaknesses. It allows representation of the public in matters regarding utility price setting, rates of return, and investment so that utilities cannot restrain supply and realize monopoly profits. However, COS has been criticized on the basis that (1) it offers utilities few financial incentives to aggressively restrain or reduce operating costs or undertake DSM initiatives; (2) it lacks incentives for productivity improvement; (3) it involves costly regulatory procedures; and (4) it is inconsistent with trends towards deregulation and increased competition.[25]

Other criticisms of traditional COS regulation arise from the fact that it tends to influence the prices charged by regulated companies only by looking backwards at the decisions of management, and focusing on the costs associated with those decisions, rather than setting prices with a forward perspective on the market.

Performance Based Regulation (PBR)

PBR is an alternative form of regulation that has been adopted as a simpler, lower cost means of regulation. In this framework multi-year performance targets are established based on an agreed formula that specifies that annual growth rate of target revenues, costs, or rates based on agreed rates for inflation and productivity. It may also include adjustments for quality of service, and the rate of growth of other costs such as increases in number of customers.

A typical PBR formula would be

Performance target = Base year target x [1 + (customer growth – productivity) x [1 + inflation] +/- Z-factors

Where

Z-factors are agreed upon positive or negative costs deemed uncontrollable by the utility.

PBR has been promoted as more effective than COS because it can reduce micro-command and control by regulators by giving utilities incentives to manage their operations within specified performance constraints. It reduces regulatory costs by streamlining updates to performance targets through the use of the agreed upon

[25] See the Symposium on price-cap regulation, *Rand Journal of Economics, 20* (3).

formula, most importantly the base year target. This base target forms the basis for performance targets in subsequent years, and it is not until the end of the PBR period (typically three to five years) that the target is updated.

> For example, the general PBR formula used at Enbridge for its overall O&M for the 2000–2002 period, agreed upon in November 1998, was
>
> Current year O&M = Base year O&M x [1 + (customer growth – productivity) x [1 + inflation] +/- Z-factors