Comparison of Time Differentiated Pricing Pilots across the United States
Lessons Learned and What's Next?
Mike Messenger, Moderator
California Energy Commission
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This panel is designed to provide an overview of the different types of pricing experiments taking place in the United States and provide a detailed discussion of the lessons learned to date during the California Dynamic Pricing pilot and then discuss what is likely to happen next in the dynamic pricing field. This paper is organized as a series of one page abstracts that highlights the areas to be covered by each of the panelists. The topics to be treated by each panelist are summarized below;

Susan McNicoll- (PG&E)	Developing the Sample and Survey Design for the California Dynamic Pricing Pilot
Kristie Delius	Recruitment of Customers for Dynamic rate Pilot
Chris King	Metering Requirements to support Dynamic Pricing Pilot
Ahmad Faruqui	Preliminary Load Impact results from Pilot
Mike Messenger	Comparison Program Features for dynamic pricing experiments in Different States

Challenges of Developing Statewide Marketing Materials to Convince Customers to Participate in the Statewide Dynamic Pricing Rate

Kristie DeIuliis (for Julie Blunden)

We were in charge of recruiting over 1000 customers to fit specific cells in a multidimensional pilot of dynamic pricing within an 8 week time frame. What follows is a list of the strategic and tactical obstacles we faced and overcame to achieve the goal of gaining customer participation in the pilot by July 1, 2003.

1) Short Deadlines and a Large Stakeholder Group:
Logistics dictated the need for a large group to make several early marketing materials development decisions in two weeks. In addition, the large "consensus" style review panel resulted in conservative, factual messages; the least common denominator effect of copywriting.

2) Key Program Decisions In Flux During Materials Development:
Marketing messages to sell customers on specific rates were being developed before the final rates were adopted and the rates changed during the marketing period. Also, decisions on the types of technology to be offered to customers lagged the decisions related to the rates-only programs.

3) Statewide Messages Developed for 32 Variations of Price/Technology Offers:
Common statewide language was needed across three utilities, for 32 different rate/program offers, with the goal being to prevent marketing materials from becoming an obstacle to research analysis. It was critical to identify and negotiate among all stakeholders in the process what messages were to be common across materials so technology and rate effects could be measured according to the intended program design.

4) Opt-out Recruitment Design:
Customers were not being recruited per se, rather randomly selected to meet market research strata requirements and convinced not to drop out.

5) Revenue Neutral Rate Design:
Revenue neutral rate design by class meant that half of customers would be better off under new rates with no behavior change and the other half would need to change to get lower bills. Also, some higher peak use customers are in a position where “saving money by changing behavior” is close to impossible.

In addition to these materials development challenges, this campaign encountered several types of customer acceptance barriers to Dynamic Rates including:

1) Bills Too Small To Matter:
Residential electric bills are small enough that a DR (TOU/CPP) rate change has to be pretty darn extraordinary to make an impression on people. In CA we are testing super peak rates that are as much as 10x the average US residential electric rate, and yet the monthly bill impact for an average customer who doesn't change any behavior might

only be $10-20, well within the range of monthly variation, especially in the summer and especially in electric/gas utility service territories.

2) Low Involvement Customers
Most customers do not pay attention to their kWh usage each month, let alone each hour. It's a big effort to get customers interested and educated about high use times, rate categories and appliances use changes that will show a bill impact. There will always be some little segment of customers interested in such things, but to have a system impact, you need at least 20% of peoples' attention. It's expensive to get it, or you have to design rates to be very persuasive, probably politically unpalatable for residential customers.

3) Selling New Rates and Control Technologies Concurrently is Tough:
Doing so complicates a message that's already got several aspects: pricing/timing/notification/override/appliance use changes etc. Anytime technology that involves an interior house visit reduces demand due to the hassle factor of making the customer be home. Without a payoff that is imminent and quantifiable (we'll pay you $50 upon installation, or we'll guarantee savings of $5 a month on your bill) customer acceptance drops precipitously.

After completing this work, our team thought about some different types of information displays that might be just as effective as dynamic prices including:

- In-Your-Face, Real-Time Energy Displays that allow customers to view their system output as well as their load. An indoor meter located in a home might have the effect of actually changing behavior for some customers, who could view variations on any given day.

Metering Requirements to Support Dynamic Pricing Experiments- Panelist 3-
Chris King-eMeter Corporation

California's Statewide Pricing Pilot includes critical peak pricing (CPP) and time-of-use (TOU) pricing for residential and small commercial customers. The metering required to support these rates includes two areas of functionality: that which is needed at a minimum to bill the rates and that which is needed to provide customers with all of the data needed to benefit from the rates. This presentation will summarize the various considerations and resulting specifications.

The rate design drives the first set of functional requirements. California's small customer TOU rates include peak and off-peak rates that differ between winter and summer. CPP rates include a TOU component; that is, the CPP rates are a TOU rate with peak and off-peak periods combined with a dispatchable critical, or "Super", peak rate. The critical peak is dispatched approximately 15 days a year. Some customers are on a "fixed" CPP, wherein the length and timing of the critical peak period are fixed, and notice of the CPP event is provided by 5 p.m. a day ahead of the event. Other customers are on a "variable" CPP, wherein the length and timing of the critical peak period vary, and notice is provided between one day and four hours ahead of the event. California's pilot does not include a "pure" CPP rate, which would be a non-TOU rate but include critical peak events.

The other set of functional requirements is driven by the Commission's desire that participating customers are able to understand and benefit from the rates. These requirements include making detailed load data to customers not only available, but in a format and vehicle that is useful to customers. These needs are affected by the desirability of rapid feedback, flexibility, privacy, and other considerations.

Preliminary Impact Evaluation of California's Pricing Pilot

Ahmad Faruqui and Stephen S. George

To measure the impact of a variety of time-differentiated pricing designs on customer usage patterns, the state of California has implemented a scientifically designed pilot program that is being run by the state's three major investor-owned utilities. The pilot, called the statewide pricing pilot (SPP), is focused on residential and small commercial and industrial customers who are under 200 kW in demand. It includes several types of rate and information treatments, including two types of critical-peak pricing (CPP) rates, a time-of-use (TOU) rate, and an information only rate.

The design encompasses three tracks, one of which (Track A) is designed to be representative of the state's population across four climate zones, another one of which (Track B) is designed to measure the impact of time-varying rates in a community faced with an environmental hazard, and a third one (Track C) where customers have price-sensitive thermostats.[1]

This paper will present preliminary impact estimates from the SPP for selected pilot treatments for the first two months of July and August. Estimates will be reported as changes in kWh usage for the peak and off-peak periods, where the peak period is defined as 2 pm to 7 pm on non-holiday weekdays and the off-peak period is defined as all other hours on the same days. In addition, it will include estimates of the impact of time-varying prices on coincident peak demand (kW).

Preliminary analysis of the July data seems to suggest that customers are responding to the time-differentiated price signals by reducing peak electricity usage in all but one climate zone (zone 1). The energy and peak impacts per household vary by climate zone and rate type. The strongest impacts are observed for the CPP-F rate on critical days for zones 2, 3 and 4. However, not all impact estimates are statistically significant. The impact of the new rates on off-peak usage is also negative or insignificant in most cases, suggesting that overall conservation of electricity usage is taking place. Finally, impacts are larger for high usage customers than for lower usage customers.

These estimates are likely to change as additional explanatory variables pertaining to appliance ownership and socio-demographic characteristics are introduced in the regression models and as August data is analyzed.

[1] For additional details, see Ahmad Faruqui and Stephen S. George, "Dynamic pricing for the mass market: California experiment," *Public Utilities Fortnightly*, July 1, 2003, pp. 33-35.

Comparison of Dynamic Pricing and Time of Use Program/ Experiment Results Across Different States --Mike Messenger

This section presents an overview and comparison of results from different dynamic pricing experiments. Table 1 provides an overview of the key aspects of the various dynamic pricing experiments to be discussed during the panel.

Table 1
Survey of Time differentiated Price Offers and Experiments
Residential Sector

Characteristics	**Gulf Power**	**Com Edison-Chicago**	**California IOU Pilot**	**Puget Sound**	**SMUD**
Rates offered	CPP/ TOU	Day ahead forecast of hourly gener prices	TOU, CPP/TOU	TOU	CPP/TOU
Targeting Strategy	To high use customers	available to all COOP members	Stratified random sample	all customers with PEM systems	Upper 50% usage for SF HH with computer and Internet
Recruitment Method	Direct mail-voluntary	COOP recruits via phone/network	Direct mail-phone follow	Direct mail	Direct Mail/Telephone
# of Customers on rates	4200	780	2000	300,000	75
Ratio of On Peak/ Critical Price	3.1 to 1	based on day ahead forecast prices	varies; range from 2.7 to 3.2	1.35 to 1	2.1 to 1
Length of CPP period	1-4 hours-variable	NA	5 hours-fixed	no CPP rates-just time of use	4 hours
Notification Period	2 hours ahead	day ahead	day ahead and four hours	NA	Day ahead
% reduction in peak use during CPP events- participants	15-20%	10 to 20%	to be announced	3 to 5%	10-25%
Key	CPP= Critical Peak Price Rate	TOU= Time of Use	NA= Not available		

* Differential became even smaller during course of experiment.

Lessons Learned from a comparison of the experimental results from Dynamic Pricing

1. Most customers are attracted initially to dynamic rates by the prospect of energy savings or bill savings but stay with the program based on a greater sense of control over their energy bills obtained through better bills and knowledge of pricing trends.
2. There is a significant amount of variation around the mean energy use observed for low, medium and high usage customers during critical peak price periods.
3. All experiments observed reductions in energy use during peak period ranging from no response to 20% drops in response to a critical peak price signal. The mean drop (depending on the length of the CPP period) appears to be 15% for customers in areas with a significant cooling load.
4. Residential customers prefer at least a four hour notice period before prices rise dramatically during a CPP event.
5. Time of use pricing alone with small differentials between on and off peak prices did not cause any significant changes in peak consumption. However time of use pricing in the California Pilot with 2 to 1 differentials had a significant effect on the peak energy usage of homes.
6. Not enough time has elapsed to determine if load impacts observed are likely to increase over time as households adjust to the price signal or diminish over time as the novelty of the new rate and or commitment to manage peak usage wanes.

ONTARIO'S ELECTRICITY SECTOR: CRISIS AND CHAOS

Marion Fraser

The Ontario electricity market opened May 1, 2002. Ontario's restructured market was faced with supply and demand pressures that no market would have desired in its first year of operation. Monthly record amounts of electricity were consumed in 10 of the first 12 months of the market. January's consumption of 14,487,000 MWh shattered a monthly record set in 1994. A new all-time peak of 25,414 MW was set on August 13, 2002. This was followed five months later with a new winter peak of 24,158 MW, breaking the previous record set nine years ago.

The average commodity price for electricity over the entire year was $62.18/MWh. A certain level of price volatility was an expected component of the market, but many consumers were unprepared for the degree of volatility and the Ontario government responded by freezing prices at 4.3 cents per kWh for homeowners and other designated customers – just over 50% of the market in terms of load. The Ontario Electric Financial Corporation, which was established to hold (and pay down) the significant debt of the old Ontario Hydro has incurred an estimated $700 million in additional debt to subsidize the difference between the wholesale price and the price cap.

In addition to freezing electricity prices for one half the market, the Ontario government has also announced wide range of "so called" tax incentives for alternative energy and conservation. However, the number and frequency of these announcements have created confusion and uncertainty in the market place. And the potential impact of tax incentives focused only on the provincial powers of taxation will be limited. In fact, the rebates on provincial sales tax for Energy Star refrigerators and air conditioners have increased the load because no corresponding bounty on old equipment was developed in parallel.

Compounding the high demand situation was generation availability that was below expectations. Some generating units experienced forced outages or delays in returning to service, low water levels reduced available hydroelectric generation and environmental restrictions limited fossil-fuelled generation — all during periods of high demand. The market — and market participants — responded to the tight situation by shifting load to off-peak hours and attracting record amounts of imports from other jurisdictions. Public appeals, for example, encouraged homeowners to cut back on power consumption. A three per cent voltage reduction was needed on only one occasion.

Even before the blackout of August 14th, Ontario's Independent Market Operator was seeking to find ways to increase the demand responsiveness of the Ontario Electricity Market. To this end, the IMO commissioned the preparation a blueprint for demand side response in Ontario, which was completed in April 2003. To date, the IMO has worked with stakeholders, primarily large industrial customers, in an effort to increase the number of loads able to be dispatched.

Ontario's Electricity System is Out of Balance

The reliability of Ontario's electric supply, long taken for granted by customers and government officials alike, is now a matter of dire concern. Economic growth, heat waves and cold snaps are driving the demand for power to new peaks and taxing an already-constrained electric power system. The government's response to freeze prices has exacerbated the problem increasing demand. To ensure the province has sufficient power for the upcoming summer, it has issued a RFP for temporary generation from potentially dirty sources. And while the current government has made progress removing barriers to alternative energy supply (primarily wind, solar and water), the government has taken little action on the demand side.

The **fundamental imbalance between supply and demand defines our province's electricity crisis."** New investments in generation and transmission are obvious reactions to reliability and price challenges, but we must also consider the very real market benefits that can be captured from the energy resources held by customers. These demand side resources should include:

- Energy efficiency
- Conservation – behavioral and operational changes, including application of interval meters or other "smart" metering systems
- Load management[a] -- interruptible and dispatchable loads, dual fuel applications, thermal storage, and demand response.
- Fuel switching
- Distributed energy[b] – includes tri-generation, co-generation, ground source heat pumps, wind and solar energy, district energy and neighborhood energy systems.

In the United States, the Federal Energy Regulatory Commission (FERC) has already recognized the importance of demand-side resources in making markets work more efficiently and more reliably. FERC has by resolution urged state regulators, power pools, and Congress to "encourage and support programs for cost-effective energy efficiency and load management investments as both a short-term and long-term strategy for enhancing the reliability of the American electric system."

This paper illustrates the role that demand side resources can play in restoring the demand-supply balance in electricity in Ontario. It also suggests a range of possible solutions to make best use of those demand side resources.

A recent US report concludes that as much as 40% to 50% of expected electric load growth over the next 20 years can be met through end-use efficiency and load management, cost-effectively and reliably.[c] There is no reason that similar results could not be achieved in Ontario. With respect to gas use in Ontario, despite adding over 50,000 customers in each of the last five years, Enbridge reports that the weather-normalized consumption of gas is virtually flat in its territory. While not all of these savings are the direct result of Enbridge's successful DSM programs, these programs and the increase in gas prices have played a significant role in changing the way in which consumers regard gas use.

The Benefits of Demand-Side Resources

A narrow focus on fixing today's weakest links in supply and delivery alone is ultimately less resilient and more expensive than a strategy that also targets enhancing demand-side investments. Utility managers and regulators are often called on to identify the immediate causes of each reliability event of public concern. It is usually possible to identify the weak link in the chain that links generation, systems operation, transmission, and distribution to customers. And, certainly, inadequate generation capacity, aging distribution infrastructure, and overloaded transmission links must be addressed to ensure reliable, high-quality service. But there are powerful reasons that electricity policy should also focus on, and seek to capture, demand-side solutions to reliability problems: avoiding new weak links; matching needs and resources; economic benefits; and environmental benefits.

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[a] This includes Demand Response (peak load management) and off-peak load management.

b This includes facilities behind the meter as well as facilities that co-generate or tri-generate and sell surplus power to the grid (embedded generation).

[c] *Efficient Reliability The Critical Role Of Demand-Side Resources In Power Systems And Markets*; Prepared by The Regulatory Assistance Project for The National Association of Regulatory Utility Commissioners

Ontario Has Used DSM As A Resource Before

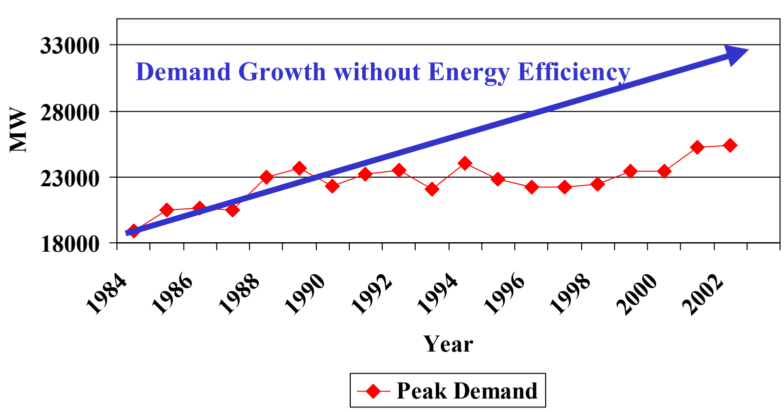
In 1988, Ontario Hydro launched a massive demand side management program and although it was disassembled in the mid 1990s and no final evaluation was completed of the result of the spending. Nevertheless, the Five Year Evaluation completed in 1993 identified that some 1500 MW of long-term savings were achieved.

In the US, utilities were pursuing similar programs and saved a total of 29,000 MW at a cost of about 3 cents per kWh saved. Despite this generally solid record of success, since the passage of the *Energy Policy Act* and the national move to retail electric competition, utility-sponsored DSM programs have been cut back sharply. Total utility DSM spending has declined by about 50% since 1993. Urgent efforts to restore those programs under crisis conditions are now underway in some states, with attendant logistical, marketing, and cost problems of off-again, on-again operations.

In Ontario utility spending on DSM has virtually disappeared. Programs such as Green Communities, the City of Toronto's Better Building Partnership, and federal Energy Innovator Programs have addressed energy efficiency and conservation, but without any link to the power system and without addressing the other resources embedded in the demand side.

The following chart "imagines" what Ontario's peak electricity demand might have become had it continued to grow at the rate it was growing in the 1980s. While the historic lockstep relationship between economic growth and increased electricity is no longer a given, one can only imagine the chaos Ontario would face if our peak demand this summer were 33,000 MW rather than 25,000 MW.

Ontario's Peak Electricity Demand
1984 - 2002



The Demand-Side Reservoir is Very Large

Even with the cutback in the US, there have continued to be studies of the potential for further savings[d]. The central lesson of these studies and initiatives is that very large reservoirs of low-cost energy and capacity resources on the customer side of the electric meter are still untapped today.

- The US Department of Energy five National Energy Laboratories concluded in 1997 that cost-effective energy efficiency investments could displace 15% of US *total electrical demand* by the year 2010.
- Customer market studies and load-response pilot programs demonstrate that the potential for load management is also quite substantial. While most of the load of most large customers is constrained by commercial and production needs, approximately 15% to 17% of their total load could be managed in response to short-term price signals. A relatively modest load response would lower peak demand, improve reliability, and lower electricity costs across regional power markets.

Market Barriers and Flaws Block Demand-Side Responses

Cost-effective energy efficiency investments are often untapped due to a number of market imperfections and market barriers faced by individual customers. These have been well documented in the DSM literature. And they continued even after the market was opened in May and prices shot up in August and September 2002. In fact, to some degree, the open market exacerbated these barriers. In a competitive generation market, generators have no financial incentive to promote either efficiency or load management, and they profit handsomely from high peak prices. And under Ontario's transmission and distribution rate designs, wires companies profit from increased throughput, and find their profits harmed by demand side programs.

Because of these structural barriers, neither generators, nor load-serving entities, nor end-users see the real value that demand-side resources can provide to the market. Thus, our electric market is more expensive, more volatile, and less reliable than it has to be.

Bring Back Demand Side Management with Adjustments for the Competitive Market

Ontario has a golden opportunity to realize and enhance the potential consumer and environmental benefits of the competitive electricity market by expanding the traditional concept and value of demand side management to include demand response and distributed energy. Under this definition, a DSM Program will include any measures that: reduce a customer's peak and overall energy demand, and/or reduce a customer's demand for **purchased** energy, by using on-site generation. Specifically, DSM should include:

- Energy efficiency
- Conservation – behavioral and operational changes, including application of interval meters or other "smart" metering systems
- Load management -- interruptible and dispatchable loads, dual fuel applications, thermal storage, and demand response.
- Fuel switching and distributed energy – includes tri-generation, co-generation, ground source heat pumps, solar energy, and district energy and neighborhood energy systems.

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[d] Some of these studies were also used by Environment Canada to supplement its climate change mitigation research.

Benefits of DSM to Customers

Demand Side Management Programs, (DSM), can provide numerous advantages for customers. These include:

- Lower energy bills for participating customers.
- Improved economic competitiveness of the jurisdiction.
- Environmental benefits including reduced emissions and improved air quality.
- System-wide load management, which lowers energy prices generally and reduces price volatility.
- Targeted DSM to reduce congestion on the transmission and distribution systems with potential transmission and distribution system cost reductions.
- Potential to defer, or eliminated entirely some capital investments in plant and equipment.
- Improved system reliability.
- Building and strengthening customer relationships and loyalty.

Benefits of DSM to the Electricity Market

The development of Demand Side Programs has several benefits to the electricity market:

- Lower consumer energy bills helps to protect consumers from rate increases
- Increased competition for energy services and contribute to economic growth
- Provides customers will enhanced opportunities for risk management, and thereby increase customer choice
- Lessen power interruptions and reductions in power quality, leading to more balanced transportation of electricity, greater system utilization and increased efficiencies in both capital and operating expenditures

Policy Options

Option 1: **Regulating**: Replicate the regulatory framework for natural gas LDC DSM.

Option 2: **Mandating**: Mandate the LDCs to spend a given percentage of revenues on DSM and establish performance indicators similar to those for other LDC performance areas.

Option 3: **Creating**: Establish a not for profit provincial agency to develop and deliver DSM.

Funding Options

- Include costs in Rates (program costs, lost revenues, shareholder incentives, wires charge to fund DSM.)
- Potential Revenues from OEFC for conservation. The current price freeze requires the OEFC to subsidize the commodity price in excess of 4.3 cents rewarding customers for consuming more energy.
- Potential revenues from the IMO for demand response.
- Potential revenues from the sale of emissions credits from DSM.
- Potential funding from Federal government re Kyoto and related programs.

Appendix 1 DSM for Ontario's Gas Distribution Utilities

In 1993, after a generic hearing, the Ontario Energy Board issued E.B.O 169-III, which established the rules (e.g. program screens, breadth of DSM portfolio, program evaluation requirements) for DSM for the three (then Centra Gas, Union Gas, and Consumers Gas) natural gas LDCs. The report was the result of a generic hearing with the three natural gas companies and interested parties (intervenors). A subgroup of these intervenors subsequently became the Externalities Collaborative, with which each of the utilities had to work on a collaborative basis to monetize externalities related to DSM. The Collaborative was to report to the Board on its findings and in so doing avoid costly regulatory hearing time. The members of the Collaborative later became the basis of Enbridge Consumers Gas' (ECG)[e] DSM Consultative, designed to be an advisory group on ECG's DSM portfolio to improve the quality of the DSM programs selected by ECG and to streamline regulatory approvals. Costs associated with the hearings, collaborative and consultative processes were borne by the gas companies and were recovered in rates.

At first, the only financial driver for the DSM programs was that the costs of economically sound programs could be recovered in rates and the expected impact (targets) of the programs was removed from 'rate base'. In other words, the gas utilities were supposedly held financially neutral in the pursuit of energy efficiency as long as the targets were met and not exceeded. However, it became clear that the regulatory framework was somewhat perverse. If targets were not met, the utility's shareholders benefited from the fact that rates had been set (higher) under the assumption that targets were achieved. In addition, there was no incentive to exceed targets, as there was no mechanism to recover the additional lost revenue. Furthermore, driving to exceed targets would likely increase costs with no way to recover them. Subsequently, the then Consumers Gas Company, applied for and received OEB approval for two additional elements: A DSMVA and a LRAM:

- DSMVA: A DSM Variance Account holds any extra costs beyond the originally approved budget until it is demonstrated that the programs remained economically sound. If so, the variance account would be cleared to the benefit of shareholders. The utility could exceed its original DSM budget by 20% without prior approval of the OEB. Beyond that, explicit approval is required. This account protects the shareholder if a program is more popular than expected. In ECG's most recent rates case (which was ongoing at the time of writing this report), the 2002 rates case, the settlement agreement restricted the DSMVA for use only to exceed the energy savings target, once the savings target had been met.
- **LRAM**: The Lost Revenue Adjustment Mechanism is also a type of variance account. If targets are exceeded, the lost revenue associated with the additional savings over what had been factored into the load forecast, and the rate calculation, could be recovered after the fact. If the targets are not met, then the excess revenue is returned to ratepayers. Again, the test that the programs continue to be economically sound is applied.

Consumers Gas applied for an additional element in the DSM regulatory framework in 1998, which was approved by the OEB in December 1998 for the 1999 fiscal year. This element was a 'shareholder incentive'. The basis for this incentive was that the DSM program generated savings for society as a whole and that a share of these savings should be returned to the shareholders and management of the company that was responsible for generating the savings. In this case, the incentive would be 35% of the net present value of the savings achieved by the company over and above its targets. In 1999, Consumers Gas targeted to help customers save 32 $10^6 m^3$ and actually achieved in excess of 50 $10^6 m^3$. The shareholder incentive associated with this over achievement was \$4.8 million. Incentives earned in 2000 and 2001 were \$3.5 million and \$4.6 respectively.

[e] The company has recently changed its name to Enbridge Gas Distribution Inc.