# Blueprint for Demand Response in Ontario

*prepared for*

***INDEPENDENT ELECTRICITY MARKET OPERATOR***

*by*

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# EXECUTIVE SUMMARY

Navigant Consulting was retained by the Independent Electricity Market Operator (IMO) to develop a blueprint for demand response in Ontario that would 1) cover the entire Ontario electricity market and all market players, 2) identify the full range of issues impeding demand response and a practical set of initiatives to address them, and 3) serve as the basis for a long range plan to improve demand response. For the purposes of this blueprint, demand response is defined as load response called for by others and price response managed by end-use customers.

***Navigant Consulting retained by the IMO to develop a blueprint for demand response in Ontario***

## Demand Response in other Markets

NYISO, NEPOOL and PJM all offer some form of economic demand response program whereby customers are essentially paid not to consume. All of these market operators have stated their preference for market price-based demand response (ie, customers respond solely to price signals, not to an incentive not to consume), but recognize the need for some economic demand response programs to "kick-start" the market. In addition to economic demand response programs, NYISO, NEPOOL and PJM all have some form of emergency demand response program. There are also several other programs that pre-date the ISOs' latest demand response initiatives, each of which provide some form of compensation to customers for reducing their load.

***NYISO, NEPOOL and PJM all offer programs where customers are paid not to consume***

Customers have widely varying needs, price responsiveness, options, and opportunity costs. Multiple program designs will be needed in order to maximize demand response in the Ontario market. These programs should reflect the fact that 1) customers want as much notice as possible, 2) minimum notification period varies by customer, 3) market value varies by notification period, 4) there are typically "shut-down" and "start-up" costs incurred by customers, and 5) many customers have minimum "down" times. Additional response could be obtained through multiple programs, including alternative designs that support participation of different types of customers not directly accessible to the IMO (eg, embedded LDC customers), perhaps through aggregators, extensions of traditional utility interruptible programs and re-establishment of residential load control programs.

***Customers have different needs and different programs will be needed to maximize demand response***

### *Residential and Small Business Initiatives*

A "Critical Peak Pricing" (CPP) program for residential and small business customers offers a standard TOU rate structure plus a "critical peak price" that would only occur on a limited number of days in a year. GulfPower in Florida has operated a CPP program since 1992 and participants have provided a 2 kW reduction ( ~ 40%) on average during summer critical peak periods. The dynamic price under a CPP program is very similar to wholesale market prices. This

***GulfPower CPP program achieved 40% peak reduction for participating customers***

similarity makes experience with CPP programs relevant to Ontario, particularly with respect to the introduction of interval meters for residential customers.

***California pilot programs can inform Ontario policy makers***

In response to a severe capacity shortfall in 2000/2001, California is pursuing a State-wide Pricing Pilot of various TOU and CPP programs for small commercial and residential customers. The primary objectives of the pilot are to 1) estimate demand elasticities for key customer segments, 2) develop demand curves to generalize results from the pilot to extrapolate to larger populations of customers, and 3) gather information on customer acceptance and opt-in or opt-out rates for different forms of dynamic rates, control technologies and information treatments. The comprehensive nature of the pilot suggests that the results could serve as valuable input to increasing demand response cost-effectively within the Ontario market.

## Market-Ready Products and Services

***Enabling technologies for demand response***

The Gulf Power CPP program utilizes a combination of products and services that represent the key elements for demand response:

- Interval meters (to measure customer consumption every 15 minutes or hourly)
- Communication of metered consumption data to the customer and the LDC or demand response aggregator
- Communication of market price and need for demand response signal to customer
- Ability of demand response aggregator or customer to execute desired response to end-use equipment
- Feedback on actual response to customer and others provided by the interval meter

***Technology is not the limiting factor for demand response***

A wide variety of technologies and options for each of these elements exist. In addition, numerous suppliers are packaging the above and other products into flexible, integrated service offerings for customers. As demand for these products increases, additional suppliers and service providers will enter the market. While there are some glitches with integrated solutions and some uncertainty regarding which particular technologies or protocols will become dominant, technology is not the limiting factor for the development of large-scale demand response programs.

## Resources Prior to Market Commencement

***Previous Ontario Hydro interruptible tariffs***

In the 1980's and early 1990's, Ontario Hydro is reported to have had about 1100 MW of interruptible load under contract. Because of load factors, about 600 – 700 MW of this interruptible capacity was actually available when needed. In the mid-1990's, Ontario Hydro started to transition customers off many of its interruptible rate offerings in response to changes in the Ontario supply situation and a desire to provide rate offerings that better reflected the benefits provided.

Most interruptible customers were given a rate discount (effectively a fixed payment) to participate, whereas the demand response programs introduced or being considered by most system operators such as PJM, NEPOOL or NYISO do not incorporate such fixed payments. Because these new programs do not provide fixed payments, they may not achieve the same level of demand response as was available under programs offering fixed payments, such as the interruptible rates previously offered by Ontario Hydro.

Seven of thirteen LDC respondents to a Navigant Consulting survey reported offering load-controlled rental water heaters in the last five years. Incentives for participating customers averaged $5/month – roughly equal to the rental cost of the water heater, hence the net rental cost for participating customers was close to zero. Navigant Consulting estimates there was approximately 45 MW to 67 MW of total demand reduction from the respondents that offered water heater load-control programs. All seven of the LDCs still have the load control infrastructure in place. Navigant Consulting estimates that the cost necessary to reactivate this control infrastructure would be approximately $20 per water heater.

***Key impediments to LDCs participating in demand response***

LDC's primary concern with respect to participating in any future demand response initiatives is recovery of the associated capital, operating and marketing costs. All respondents also mentioned the lack of any meaningful customer incentive under the current retail rate freeze as an impediment.

## Current Market Situation

The Ontario wholesale electricity market is characterized by relatively tight supply, discrepancies between pre-dispatch and real-time prices and absence of a short-term (eg, hour-ahead or day-ahead) forward market. These factors impede demand response in Ontario. The IMO is taking the initiative to reduce the level of discrepancy between pre-dispatch and real-time prices, and is exploring mechanisms to facilitate demand response.

***Wholesale Market Participant perspective***

Large customers that are wholesale market participants likely represent the best opportunity for short-term demand response. Based on an informal survey of a small group of wholesale market participants, the largest single barrier to the surveyed customers is the unreliability of the IMO's pre-dispatch price signal. The volatility of the 5 minute market clearing price (MCP) makes demand response extremely difficult. Customers cannot predict with any accuracy what the price will be and this results in customers either running through high priced periods, or shutting down during low priced periods.

With respect to their ability to respond to an accurate pre-dispatch signal, all customers would prefer one day notice, but many are able to respond within one hour, and some can respond within five minutes. This finding highlights the significant variation in response time among large, sophisticated customers and supports the efforts of other ISOs to provide a range of programs, with differing notification periods, to wholesale market participants.

***Half of market volume is no longer exposed to wholesale market prices***

The introduction of Bill 210 and subsequent regulation has resulted in fixed retail prices for low volume and designated customers representing approximately 50% of market volume, and more than 50% of peak demand, through 2006. The retail price freeze will impede demand response. Under the price freeze, the Government is responsible for buying the cost of power for this group of customers from the wholesale market price down to the fixed retail price. As such, any reductions in the wholesale cost of power for this customer group through demand response would accrue directly to the Government.

Bill 210 also requires Ministerial approval of all transmission and distribution rate applications, which has had the effect of capping transmission and distribution rates (absent Ministerial approval). As a result of the distribution rate cap, LDCs may be less willing to undertake demand response than they might otherwise have been unless they are mandated to do so and/or the costs they incur for doing so are recoverable through rates.

Many retailers have either shut down or significantly downsized their operations in response to Bill 210. However, Navigant Consulting expects that some retailers will continue to operate in the Ontario market and some level of retailer support in demand response may be anticipated.

### *Net System Load Shape*

***Net System Load Shape simplifies retail settlement but is an impediment to demand response***

One of the key features of the Ontario electricity market's retail settlement rules is that, with the exception of street lighting, all customers without interval meters in a given LDC are assumed to have the same load profile. This load profile is called the Net System Load Shape (NSLS). The NSLS greatly simplifies retail settlement but is an impediment to demand response. The retail price freeze exacerbates this problem, suggesting that without changes to recognize and reward demand response among this customer group, there will be no meaningful demand response from NSLS customers under the retail price freeze.

There are a wide variety of options to address these two issues and facilitate customer demand response, typically involving some combination of interval metering, dynamic pricing and possibly enabling technologies. Whichever options prove most viable, there are several critical issues that must be addressed:

- How should the capital and operating costs of the infrastructure necessary to allow these options be allocated between participants, non-participants and the entities incurring these capital and operating costs?

- As the primary beneficiary of demand response among low volume and designated customers while the retail rate freeze is in effect, should the Government provide a financial contribution to participating customers and / or LDCs?

***Key policy issues to facilitate demand response among customers eligible for the retail price freeze***

## Valuing Demand Response

Numerous analyses and studies have indicated that demand response during periods of high prices can result in lower overall costs for all customers, not just those providing the demand response. Based on confidential information provided by the IMO, Navigant Consulting estimates that if the Ontario market had 250 MW of additional demand response (~ 1% of peak Ontario demand) during those periods when HOEP was greater than $120 / MWh, average prices in Ontario since market opening would have been almost 2% lower, representing approximately $170 million in reduced electricity costs for all customers. This reflects the fact that the Ontario supply curve is quite steep whenever HOEP is greater than $100 / MWh and small reductions in demand can have a significant impact on market prices.

***250 MW of incremental demand response in Ontario would have reduced wholesale electricity costs by $170 M since market opening***

Assuming the customers providing the additional 250 MW of demand response had done so based strictly on price signals, this would be an efficient market outcome. If, however, there was another group of customers who were not willing to respond based solely on market price signals, but who would provide demand response of perhaps 100 MW if they were paid the market price for the energy they did not use (analogous to an "economic" demand response program where customers are paid not to consume), the situation becomes more complicated. Further, if the original group of customers providing 250 MW of demand response also demand to be paid not to consume, the situation becomes even more complicated. However, assuming that all 350 MW of demand response were paid "not to consume", the flow of costs and benefits based on the confidential information provided by the IMO for the Ontario market would be as follows:

- The original group of customers who would have provided 250 MW of demand response anyway would reduce their electricity costs by $20 million and would also be paid approximately $17M (assuming the payment was based on the lower HOEP) by other customers "not to consume".

- The second group of customers who would only provide 100 MW of demand if they were "paid" to do so would reduce their electricity costs by $8 million and would also be paid approximately $7M by other customers.

***Flow of costs and benefits with an economic demand response program in which customers are paid not to consume***

- Other customers would have saved approximately $235 million due to lower HOEP, but would have paid $24 million to realize these savings
- Generators would have received approximately $263 million less revenues due to lower HOEP and lower energy sales.

From an customer perspective, this transaction makes sense. The group of customers providing the demand response can be seen to be receiving the value to the system of their agreement to reduce consumption. Note that in an electricity pool market, most generators (all those except the one on the margin) get a price above the amount they would have accepted. That is the point of having a single market price. Similarly, in the case of demand response, a case could be made that all consumers providing a similar type of demand response should get the same (market) price, regardless of their reservation price (ie, regardless of how much it is worth to them).

It should be noted also that the reduction in electricity cost from reduced consumption is not a dollar for dollar increase in profit for the consumer. The consumer had a productive use for the electricity. By reducing demand, the customer is foregoing that productive use and the profit it would have made from that use.

In situations where there is a supplemental payment to consumers there is an equity concern. Consumers benefit and suppliers are disadvantaged. This raises questions as to whether the IMO should undertake an activity that pits two classes of market participants against each other. However, given that there are clear consumer benefits it would be an activity that consumers may desire to undertake.

***Benefits of economic demand response may be transitory***

To the degree that higher prices are needed to incent the development of additional generating capacity, then the benefits of any economic demand response program can be viewed as transitory since these higher prices will have to be realized eventually to enable generators to realize an adequate return on their investment. While these savings will not be realized indefinitely, they are likely to be significant and meaningful reductions in costs for consumers.

***Key issues with valuing demand response***

This simple example highlights some of the issues associated with valuing demand response: 1) customers as a group are not well placed to makes the sorts of economic tradeoffs and demand/supply optimizations described in the previous hypothetical examples, and 2) most competitive electricity markets are structured to minimize supply costs given a market demand; competitive electricity markets are not structured to optimally balance supply and demand.

***There is merit in offering economic demand response program to 'kick start" the market***

This analysis suggests that there is merit in offering an "economic" demand response program (ie, paying customers not to consume) in order to "kick-start" the demand response market provided that the estimated incremental impact of offering an economic demand response program is within economically acceptable limits. However, given that these programs result in a wealth transfer from generators to loads Navigant Consulting believes that this may not be an appropriate role for the IMO who must be able to balance the interests of all classes of market participants. However, given that the Ontario Government has taken on responsibility for market prices greater than $43/MWh for approximately half of the Ontario market it would be appropriate for the Government to sponsor economic demand response programs.

## Recommendations

Based on IMO forecasts, reserve margins for summer of 2003 and the period leading into the summer of 2004 are expected to be adequate under normal weather scenarios and inadequate under extreme weather conditions[a]. Beyond 2003, the critical period going forward is likely to be in the 2005 – 2006 time frame.

***Short-term goals for summer 2003***

Given these market considerations and recognizing that capturing the full potential demand response from a given market segment takes time, Navigant Consulting believes that an appropriate short term goal (ie, by end of summer 2003) for Ontario would be:

- Articulating a "vision" for demand response in the Ontario market.
- Capturing readily available demand response opportunities, such as among wholesale market participants and customers with water heater load controls.
- Initiating several pilots covering all market segments to determine the most effective combination of metering, pricing and enabling technologies.

***Medium term goals for 2005***

Over the medium term (say by 2005), additional demand response could be expected from the following mechanisms:

- The IMO will have a wide variety of demand response programs for wholesale market participants and accessible to other customers (through aggregators).
- Customers with interval meters that are exposed to wholesale market prices will have a wide range of choices with respect to other enabling technologies,

a *18 Month Outlook: An Assessment of the Reliability of the Ontario Electricity System from January 2003 to June 2004*, Independent Electricity Market Operator, January 6, 2003 such as direct control and/or smart controls to help them manage demand in response to price.

- Policies and rules regarding appropriate "tariffs" and installation of interval meters and other enabling technologies for low volume customers will be finalized.
- Installation of interval meters and other enabling technologies as appropriate among eligible or targeted low volume customers will have begun.

### *Co-ordination between the IMO, the OEB and the Government*

***Need for co-operation and co-ordination between the Government, the OEB and the IMO***

Given the cross-cutting nature of the various issues and opportunities associated with demand response in the Ontario electricity market, Navigant Consulting believes there is a strong need for co-operation and co-ordination between the Government, the OEB and the IMO, with input from LDCs, retailers and market participants as appropriate. One possible approach to achieve the necessary level of co-ordination would be the establishment of a joint Government, OEB and IMO Demand Response Task Force. The need for a multi-lateral, integrated approach has been recognized in California and New York.

### *Recommended IMO Actions*

1. ***The IMO should ensure that discrepancies between pre-dispatch and real time pricing and volatility of real-time prices are minimized to facilitate demand response***
2. ***The IMO should co-ordinate activities with the Government and OEB with respect to demand response***
3. ***The IMO should participate in generic demand response consultations or proceedings as required***
4. ***The IMO should effect the necessary changes to market rules as appropriate***
5. ***The IMO should continue the EDRP and consider allowing other customers to bid standby generators (up to a pre-determined maximum capacity) into the program***
6. ***The IMO should continue to aggressively encourage greater dispatchable load and operating reserve market participation by wholesale market participants***
7. ***The IMO should implement the Hour Ahead Dispatchable Load (HADL) program for the summer of 2003***
8. ***The IMO should take a more aggressive role in educating customers, LDCs, retailers and potential demand response aggregators on demand response and load shifting***

***9. The IMO (working with the OEB) should explore mechanisms to allow embedded LDC loads to participate in the EDRP and other IMO programs***

***10. The IMO should consider allowing LDCs and other market players, such as retailers, to serve as aggregators***

***11. The IMO should explore the costs and benefits of introducing one or more Economic Demand Response programs***

***Possible Government Actions***

***12. The Government could direct the OEB to undertake a generic proceeding on demand response to consider the various issues impeding demand response and develop appropriate policies and codes to encourage greater demand response in the Ontario market***

***13. The Government could assess the costs and benefits of the Government or a government agency funding some of the necessary infrastructure costs and pilot programs to encourage demand response in the Ontario market***

***14. The Government could seek input from the Ministry of Environment on the potential to use standby generators in EDRP and explore special permitting exemptions regarding use for EDRP participation or confirm that existing permitting requirements would allow EDRP participation***

***Possible OEB Actions***

***15. The OEB could take the lead role in a generic demand response proceeding and could effect the necessary code changes as appropriate at the retail level.***

***16. The OEB could consider making installation of interval meters down to 200 kW (or 100 kW) for existing customers mandatory by the summer of 2004***

***17. The OEB could work with the Government and the Electricity Distributors Association (EDA) to design pilot programs intended to determine the most cost-effective means of introducing interval meters and enabling technologies in the low volume customer segment***

***18. The OEB could work with government and service providers to design pilot / demonstration projects to help communicate the benefits of and mechanisms for demand response among the various segments (eg, retail, hospitality, industrial, offices, etc.) of larger embedded LDC customers***

***19. The OEB could consider developing a methodology to allow determination of fair and equitable time-differentiated distribution charges to be undertaken by a representative sample of LDCs as part of their upcoming cost allocation studies***

***20. The OEB could explore the potential costs and benefits of requiring LDCs to charge uplift on an hourly basis for customers with interval meters***

***21. The OEB could review and clarify the role of LDCs in facilitating demand response vis-à-vis other market participants***

### *Interval Meters for New Homes*

***With dynamic pricing, interval meters for new homes would increase demand response but specific benefits are not known with any certainty***

Navigant Consulting believes that providing interval meters for new homes[a] would increase demand response in the market (provided customers were also provided with a market-based time varying price signal), but the specific benefits are not known with any level of certainty, nor are the optimal rate/product offerings to maximize the benefits known. Questions relating to the optimal technology infrastructure and tariffs under a retail price freeze regime can be addressed through a series of multi-LDC pilot programs[b]. Pilots could cover new homes, existing homes and different rate/product offerings. Information from other markets, such as California, would complement findings from any local pilots.

### *Direct Load Control by LDCs*

The Government, OEB and IMO should explore mechanisms to allow direct control of water heaters by LDCs in order to provide incremental demand response for the summer of 2003 and beyond. Based on survey responses extrapolated to the entire population of LDCs and assuming an aggressive implementation and marketing plan, Navigant Consulting estimates that between 30 to 60 MW of direct load control could be in place for the summer of 2003.

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a The government is currently considering the implementation of a policy requiring interval meters be installed at all new homes. Assuming $400/interval meter (versus $75/meter for a standard meter) and 75,000 new homes constructed in Ontario each year, such a policy would cost up to $25M each year, plus additional data management and settlement costs.

b Navigant Consulting understands that several LDCs are currently installing interval meters at customers' homes on a trial basis. Without a co-ordinated plan, any learnings from these installations are likely to be statistically unreliable.

# INTRODUCTION

***Objectives for the blueprint***

Navigant Consulting was retained by the Independent Electricity Market Operator (IMO) to develop a blueprint for demand response in Ontario. The IMO's stated objectives for the blueprint are that it should:

- Cover the entire Ontario electricity market and all market players, not just the IMO-administered market but also the retail electricity market;
- Identify the full range of issues impeding demand response and a practical set of initiatives to address them; and,
- Serve as the basis for a long range plan (market participants should be able to refer to this blueprint five years hence and recognize the progress that has been made).

Given the required breadth of the blueprint, available budget and time, Navigant Consulting was not able to go into great depth in any particular area. As such, the blueprint does not provide fine detail regarding possible IMO programs for implementation for the summer of 2003, but does provide suggestions for IMO consideration. These suggestions are reinforced by the experiences, programs and plans of other North American ISOs.

Demand response means many different things to many different people. The following definition was used to focus Navigant Consulting's analysis and recommendations:

***Definition of demand response for this report***

> *Demand response in electricity is defined as load response called for by others and price response managed by end-use customers. Load response includes: direct load control, such as of residential air conditioners; partial or curtailable load reductions; and complete load interruptions. Those calling for load response include: independent system operators (ISOs), load serving entities (LSEs), and utility distribution companies (UDCs). Price response includes real-time pricing, dynamic pricing, coincident peak pricing, time-of-use rates and demand bidding or buyback programs*[a].

Based on this definition, demand response can be viewed as a subset of broader demand-side management and conservation activities.

It should be noted that Navigant Consulting has a general bias towards and preference for market-based solutions, but also recognizes Ontario's unique market situation and the need for bold action to facilitate improved demand

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[a] *Demand Response: Principles for Regulatory Guidance*, Peak Load Management Alliance, February 2002, as referenced in the National Association of Regulatory Utility Commissioner's White Paper entitled Policy and Technical Issues Associated with ISO Demand Response Programs

response. In this regard, one additional consideration is the perceived need to create a level playing field between the supply and demand sides, however Ontario may need to overcome some institutional, regulatory and other barriers to achieve this level playing field.

***Structure of this report***

This blueprint is organized as follows:

- The first section following this introduction discusses demand response in other markets, including both ISO-based markets and other regulated markets with interesting programs and results.
- The second section discusses market-ready products and services.
- The third section addresses the demand response resources that were available in Ontario prior to market commencement.
- The fourth section discusses the current market situation and various impediments to demand response including a variety of metering and rate tariff practices.
- The fifth section discusses the value of demand response from a variety of perspectives.
- Finally, a vision for demand response in Ontario is presented in the sixth section. This section also includes recommendations for the IMO and suggestions for the Government and Ontario Energy Board (OEB), as well as detailed discussion of topical areas, such as interval meters for new homes.

Appendix A provides details of other ISO's demand response programs, Appendix B provides a discussion of measurement approaches used in other markets and recommendations for Ontario and Appendix C provides a glossary of terms and acronyms used in this report.

# DEMAND RESPONSE IN OTHER MARKETS

***Explored NYISO, NEPOOL and PJM demand response programs***

Navigant Consulting explored demand response programs offered in other Independent System Operator (ISO)-based markets. These markets included those administered by:

- New York Independent System Operator (NYISO);
- New England Power Pool (NEPOOL); and
- Pennsylvania Jersey Maryland Interconnection Inc. (PJM).

As discussed below, all of these ISO's offer a variety of demand response programs. It is also interesting to note that in its proposed Standard Market Design (SMD), the Federal Energy Regulatory Commission (FERC) has provided a strong endorsement of the need for demand response in electricity markets. Hence, Navigant Consulting expects that many of the demand response programs currently offered by ISOs, as well as new programs intended to enhance the "reach" of ISO-based demand response programs, will become part of the SMD.

This section also covers other demand response programs that have one or more characteristics that could be beneficial and applicable in Ontario or that provide other valuable insights for Ontario. These programs include Real-Time Pricing; Direct Load Control of Residential Appliances; and Critical Peak Pricing.

## ISO Programs

Highlights of the demand response activities in other ISO-based markets are provided below. Details are provided in *Appendix A: Details of other ISO DR Programs* on page A79.

***Most ISO programs relatively new, participation will likely increase over time***

In viewing the highlights, it is important to recognize that most of the programs offered by the ISOs are relatively new. Hence Navigant Consulting believes the level of participation and demand response available is not representative of what would be achievable in the longer term with further program refinement, and greater customer experience and education.

***NYISO, NEPOOL and PJM offer economic demand response programs (ie, pay customers not to consume)***

NYISO, NEPOOL and PJM all offer some form of economic demand response program whereby customers are essentially paid not to consume power they otherwise would have. All of these market operators have stated their general preference for market price-based demand response (ie, customers respond solely to price signals, not to some incentive not to consume), but recognize the need for some economic demand response programs to "kick-start" the market.

It is also interesting to note that, in spite of their stated preference for market price-based demand response that, strictly speaking, would be market-driven with little ISO involvement, most of the ISO's are expanding their demand response program portfolio. This represents efforts by the ISOs to create a level playing field between demand-side and supply-side (ie, generators) resources, expand the population of customers and market intermediaries that can provide demand response and overcome certain institutional and market barriers for demand response. Whether all of these impediments can be sufficiently addressed over time in order to allow reliance exclusively on market-driven demand response remains to be seen.

In addition to economic demand response programs, NYISO, NEPOOL and PJM all have some form of emergency demand response program.

Other demand response programs currently in place include NY ISO's Installed Capacity Special Case Resources program (ICAP SCR), NEPOOL's interruptible load program, and PJM's Active Load Management (ALM) program. These programs provide a fixed payment of some form and pre-date the concerted demand response initiatives that have led to the emergency and economic demand response programs. As a result, customers have more experience with these programs, and consequentially, the level of participation in these older programs is greater. NEPOOL intends to replace its interruptible load program with a more extensive offering of emergency and economic demand response programs.

***Alberta, UK and Australian demand response programs***

Looking to other markets, the Alberta Power Pool has a voluntary load curtailment program where payments are made only for actual curtailments. This program was used extensively in past years when supply was tight and prices were high, but has not been active recently. In the United Kingdom, loads can bid demand response into the real-time balancing market, as well as operating reserve and frequency control markets. In Australia, load can be bid as dispatchable and can also bid into ancillary services market, much like in Ontario. Different Australian states are currently exploring various methods of increasing demand response. For example, New South Wales takes a holistic approach looking at environmentally driven, network driven, and retail market driven initiatives. Victoria currently gets most of its demand response through retailers signing off-market customers to voluntary curtailment contracts. Independent specialist aggregators are being suggested as a means of increasing demand response since retailer contracts are too short. This highlights the critical disconnect between the typical retailer contract duration (say two or three years) and the period over which the necessary investments to facilitate demand response need to be amortized (say ten years).

### *Key Features of Other ISO Demand Response Programs*

The key features from the other markets investigated are presented below. Only general trends and features are provided here. For a more detailed description of the ISO programs, see *Appendix A: Details of other ISO DR Programs* on page A79.

- Minimum response size of 500 kW to 1 MW is typical, although thresholds as small as 100 kW have been set for some programs.

***Use of aggregators***

- Many program participants act through a third party, who is a market participant. In many cases, these third parties are simply offering pre-existing interruptible programs. Demand response aggregators and LSE's are often required to be agent for participation because the ISO doesn't have the capability and resources to deal with smaller individual end-users.
- ISOs either currently allow or intend to facilitate specialist aggregators.

***Day-ahead demand response programs***

- In spite of their stated preference for market price-based demand response, NYISO, NEPOOL and PJM currently have or plan to develop a day-ahead economic demand response program.
- Day-ahead economic programs, which require participants to submit bids, pay out the maximum of the market clearing price (MCP) or the bid price, and the bid price can set the MCP.
- Real-time economic programs can have bids or not. If bids are used, the program will pay the maximum of the MCP and the bid for demand response. If bids are not used, or a bid is not submitted (in the case of programs where bids are optional), demand response is paid the MCP.
- For NYISO and PJM, the price paid is the locational marginal price (LMP); for NEPOOL, the price paid is the region-wide MCP.

***Fixed minimum price is a feature of most economic programs***

- A fixed minimum price is a feature of most economic programs. Others are considering adding this as a way to increase participation.
- Cost recovery for economic programs is typically from all market participants, but PJM's economic programs recover costs from the LSE serving the customer who responds (in this case, the LSE receives benefits from the demand response, such as lower UCAP requirements, so they do not lose money from this payment).

- For emergency/reliability programs, a common practice is to pay some reservation payment based on operating reserve prices. New England uses such payments in their emergency demand response program (entitled real-time demand response program), as does the NYISO in their ICAP SCR program. In PJM, where no reservation payment is made, customers may also participate in the Active Load Management program, and receive a reservation payment from their LSE that way. The NYISO formerly allowed customers in their emergency demand response program to also participate in their ICAP SCR program, but discontinued that practice in early 2003.

***Common practice is to pay some reservation payment based on operating reserve prices***

- Where no reservation payment is made, the price paid is the maximum of the MCP and some fixed price, typically $500/MWh (USD). Where a reservation payment is made, the price paid for actual load reduction is the MCP, with a maximum value imposed.

- Costs of emergency programs are typically recovered either from all customers in the market, or from all customers in the affected zone.

- All ISOs currently have or intend to implement some form of profiling demand response program for non-interval metered customers.

***Profiling for non-interval metered customers***

- Use of standby generators is allowed in most markets, subject to local air quality regulations.

- The total response in the portfolio of NY ISO, PJM and CA DR programs ranged from 3% to 5% of peak demand. The best results (as a percentage of overall market peak demand) for each type of program:
  - Actual response for NY Emergency Demand Response Program (EDRP) was 2.2% of market peak demand, within two years of program rollout.
  - Actual response for PJM ALM program was 2.8% of market.
  - Actual response for PJM Economic Demand Response program was 0.2% of market.

***Total response in the portfolio of programs ranged from 3% to 5% of peak demand***

Although the ISO results are impressive, the level of demand response (expressed as a percentage of overall market peak demand) is generally less than that achieved through the best demand response programs offered by vertically integrated utilities. The reasons for this lower level of demand response in ISO-based markets include:

***ISO-based demand response less than the best results from vertically integrated utilities***

- Program immaturity (the ISO programs are relatively new, whereas many vertically integrated utilities have been offering a variety of demand response programs for many years);

- Restructured markets are more fragmented, with more "seams" issues between various market participants. Vertically-integrated utilities don't experience these issues (or at least not to the same extent);

- ISO programs typically provide variable and uncertain payments, whereas many utility programs provide fixed and predictable payments;

- Load serving entities have limited capabilities to incorporate demand response into their commodity offerings; and

- In a vertically integrated utility, the benefits of demand response are readily quantified and flow directly to the utility, hence they are better placed to "value" demand response and to offer programs that fully reflect the system value. In a restructured market, the benefits of demand response do not accrue to any single market participant.

### *Key Take-Aways for Ontario*

Based on experience and lessons learned in other ISO markets, Ontario could reasonably expect to secure:

- Between 500 and 600 MW of demand response through emergency program (ie, EDRP) in the long term. This is consistent with the approximately 370 MW that is enrolled in the current IMO program during its first year

- Perhaps 500 to 750 MW through a program offering customers fixed (eg, monthly) participation payments (this type of program could be seen as a variant on an economic demand response program). Note that these programs typically reflect a flow-through of operating reserve and/or resource adequacy payments in other markets and participating customers generally have previous experience in utility interruptible programs[a].

- Approximately 50 to 100 MW of demand response from an economic demand response program which paid customers the wholesale market price not to consume, but this would be expected to increase over time with customer and market experience. In the absence of a program offering a fixed monthly payment (as described above), the response to an economic demand response program would likely be much greater than 100 MW.

***Based on experience in other markets, Ontario could expect…***

- ***up to 600 MW for emergency program,***
- ***up to 750 MW for a program offering fixed participation payments, and***
- ***up to 100 MW in economic demand response***

[a] Since the IMO has not yet determined the structure of a resource adequacy mechanism for Ontario (if any), it may be premature to implement such a program. If and when such a mechanism is introduced in the Ontario market, the IMO should consider how the mechanism could support enhanced demand response in the Ontario market.

***Customers have widely varying needs, and programs should reflect this diversity***

Customers have widely varying needs, price responsiveness, options, and opportunity costs. Multiple program designs will be needed in order to maximize demand response in the Ontario market. These programs should reflect the fact that 1) customers want as much notice as possible, 2) minimum notification period varies by customer, 3) market value varies by notification period, 4) there are typically "shut-down" and "start-up" costs incurred by customers, and 5) many customers have minimum "down" times. NEPOOL's plan to offer a wide range of programs for customers with different lead times could work well in Ontario. Taken to an extreme, a day-ahead program should be considered if a day-ahead market is introduced in Ontario.

Additional response could be obtained through multiple programs, including alternative designs that support participation of different types of customers not directly accessible to the IMO (eg, embedded LDC customers), perhaps through extensions of traditional utility interruptible programs and re-establishment of residential load control programs.

***Simple programs that recognize unique characteristics of demand response***

Programs should be as simple as possible and recognize the unique characteristics of demand resources. Hence, the bidding rules for demand response resources don't need to be identical to those for supply-side resources. For example, customers that can only shed load for three hours could be treated as an energy limited resource in the resource stack (comparable to some hydro and emission constrained peakers).

***Aggregators are vital to maximizing demand response***

Aggregators allow access to retail customers and can enhance participation of wholesale market participants. In the case of wholesale market participants, demand response aggregators can be important because i) the contract length for demand response may have to be much longer than is typical for a commodity supplier in order to recover controls and communications infrastructure costs, and ii) demand response must be marketed and "sold" differently from the energy commodity. If demand response aggregators were allowed to participate in the Ontario market, Navigant Consulting expects that these aggregators would become an important source of innovation. Under the current market rules, LDCs are the only market participants that can serve as aggregators of load for non-wholesale market participants, yet other market rules, code and regulation preclude LDCs from receiving any of the capacity and commodity benefits from demand response. Based on this, rule changes to allow for third-party aggregators must be considered, as should methods of facilitating the creation of such aggregators.

***Greater price certainty and fixed payments***

One of the central issues in developing effective demand response programs and supporting mechanisms is that demand response is only required infrequently[a], yet there are significant fixed costs needed to facilitate demand response. How can end-users and aggregators be compensated for their costs when the response may be needed for only 100 hours every three to five years? Clearly, enhanced demand response would have been valuable to the Ontario market in the summer of 2002 but it may be less valuable in 2004 (based on the forecast return schedule of the laid-up nuclear capacity). As stated above, a fixed payment attracts more customers to sign up for the program, albeit at a higher cost. Capacity payments or resource adequacy payments can provide a fixed payment to address this customer concern. The key issue is whether the incremental cost of the demand response is less than the incremental cost of adding generation capacity. This highlights the need to consider mechanisms to encourage demand response in developing a resource adequacy mechanism for Ontario.

***Who should pay for demand response?***

Cost recovery of demand response payments and incentives remains a big issue. Most ISOs socialize the costs of emergency and demand response, either on a market-wide basis through uplift, or on a local/zonal basis. This is appropriate since the benefits of demand response (lower prices and greater reliability) accrue to all consumers.

***Use of standby generators***

Use of standby generators in demand response programs is controversial due to their potential environmental impacts. Any investigation of this issue should consider the likelihood and environmental impact of load shedding (which would result in the operation of many more standby generators) if standby generators are not allowed as a demand response resource.

## Other Demand Response Programs

***Other programs from regulated electricity markets could be applicable in Ontario***

Other demand response programs from regulated electricity markets with one or more elements that could be applicable in Ontario or that provide valuable insight for Ontario include real-time pricing, direct load control of residential appliances, and critical peak pricing. Highlights of these other programs are provided below along with a discussion of the various initiatives that the State of California has undertaken to enhance demand response.

### *Real-Time Pricing Programs[b]*

Georgia Power's Real-Time Pricing (RTP) program is one of the longest-running and possibly the largest non-ISO demand response programs in the world. 1,600

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a Load shifting in response to daily price patterns is an exception, but would also provide demand relief during periods of high-prices

b *Dynamic Pricing, Tariffs and Price Responsive Demand Programs, Real Time Pricing at Georgia Power Company and Duke Power Company*, Christensen Associates, September 2002.

customers representing more than 5000 MW participate. Under the program Georgia Power offers both Day-ahead RTP and Hour-ahead RTP.

Pricing for participating customers is based on the customer's load profile relative to a baseline based on recent historical usage. Customers typically "sell" load at high RTP prices (ie, they reduce their load below their baseline) and "buy" load at low RTP prices (ie, they increase their load above their baseline). As such, the Georgia Power RTP program could be considered an "economic" demand response program in that customers are paid not to use power during high price periods. However, there is one significant difference from the ISO-based economic demand response programs described previously – customers in an ISO-based market are fully exposed to wholesale market prices whereas Georgia Power RTP customers are not exposed to high RTP price signals if they maintain their load profile within their baseline (in these circumstances, they simple pay the fixed tariff). Hence, this program gives customers a significant degree of protection and flexibility that would not be available to a wholesale market customer in a competitive market (whose entire consumption is exposed to high prices during high priced periods).

Key results from the Georgia Power RTP program are:

***Key results from the Georgia Power RTP program***

- 60 to 75% of customers on the RTP tariff respond significantly to RTP prices.
- Minimal response was observed for RTPs less than $200/MWh (suggesting some sort of "opportunity cost" threshold for customers – if the benefits of demand response are not significant enough, they won't respond).
- As the number of periods with high prices occurs with greater frequency, customers tended to exhibit less price response.

### *Direct Load Control*

Several utilities have offered programs in which they directly control certain appliances within a customer home – such as air conditioners or water heaters – or within a commercial or industrial facility to reduce peak demand.

***Several utilities offer programs in which they directly control certain appliances in a customer home***

Although there has been some backlash from customers in programs in which the utilities were too aggressive with their load control strategies, these types of programs have generally been very successful. In some programs, customers are allowed to override the utility's control signal for a limited number of times each year. This provides customers with some control and likely helps to enhance participation rates.

Ontario utilities operated successful water heater load controls programs for years (see *LDC water heater load control programs* on page 34). The Ontario utility water heater load programs were generally effective because customers did not experience any negative impact on the end-use service (supply of hot water) from the load control.

From a customer perspective, these programs are very simple – in return for some incentive (say $5/month), they allow the utility to control one or more loads in their house or commercial building. They also highlight the importance of customer choice – if the incentive is not high enough or the control strategy is too aggressive, customers can choose not to participate.

***Direct control could be offered by aggregators, but they face several issues that utilities don't***

Although most of direct load control programs involved utilities that provided the control infrastructure and customer incentive, this concept would also be applicable for demand response aggregators, but there are several issues that would need to be addressed in a competitive market. Perhaps the most significant issue is that the term of contract required to justify installation of the necessary control infrastructure is longer than most customers are willing to sign contracts for commodity purchases. The second issue is that, depending on their views on the value of demand response and rate allocation methodologies, utilities could recover the costs of the control infrastructure from all of their customers, not just the participating customers. In contrast, aggregators would need to recover their costs exclusively from participating customers.

### *Critical Peak Pricing*

Most Time-of-Use programs offer fixed prices and fixed time periods in which these fixed prices apply. These programs have proven to have some impact on demand[a]. In contrast, a "Critical Peak Pricing" (CPP) program offers TOU rate structure, plus a "critical peak price". The timing of the critical peak price is dynamic and the pricing could also be dynamic. An illustrative example of a CPP rate versus TOU rate versus a standard flat rate is shown below.

[a] TOU programs have been demonstrated to have measurable impact upon energy usage during peak periods, particularly (1) if the ratio of on-peak to off-peak prices is greater than 2; (2) within selected segments of customers; and (3) there are programs/mechanisms for educating customers about the rate structure and developing strategies for responding to the rate structure.

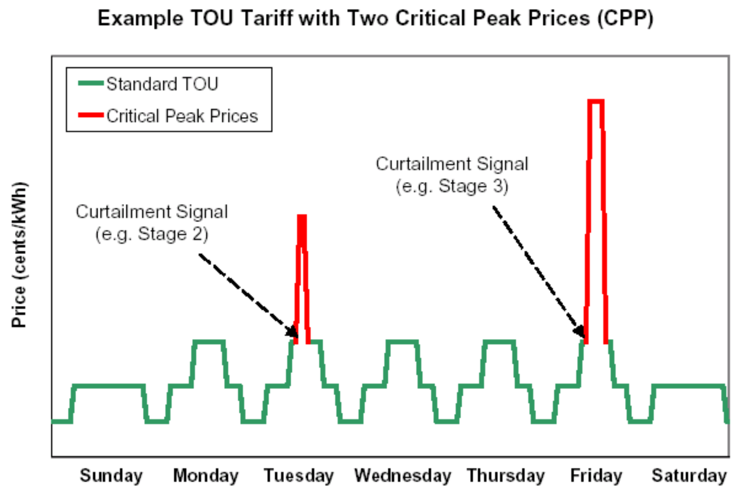


***Figure 1 – Comparison of TOU versus CPP Rate Structure***

Source*: An Action Plan to Develop more Demand Response in California's Electricity Market*, California Energy Commission. July 2002

Note that the critical peak pricing would only occur on a limited number of days in a year (perhaps 10 to 20 depending on weather and the local demand / supply balance). At other times, the price would be similar to a standard TOU rate. Note also that the prices for each of the different TOU periods (and possibly including the critical peak price) could be set to be revenue neutral for an average customer compared with the standard, non-time-varying fixed price. Hence, an average customer that does not change their behaviour would face the same electricity costs under the CPP option as under the standard, non-time-varying fixed price.

***Dynamic pricing of CPP programs makes them relevant for Ontario, particularly for discussion of interval meters***

The dynamic price offered to customers under a CPP program is very similar to wholesale market prices – generally wholesale electricity markets exhibit relatively stable diurnal and seasonal pricing patterns with occasional price spikes. This similarity is what makes experience with CPP programs most relevant to Ontario, particularly with respect to the introduction of interval meters for residential customers (along with some form of market-reflective price or incentive).

Gulf Power in Florida has been operating a CPP program since 1992 and has achieved promising results. The results from CPP pilot program[a] indicated that:

- Participants provided a 2 kW reduction (~40%) during summer critical peak periods and almost 3 kW reduction (> 50%) during winter critical peak periods (this suggests that most of the participants had electric heating). High and medium price periods also exhibited demand reductions (>20% and ~5%, respectively), with low price periods experiencing an increase in demand of just over 10%.

[a] *Critical Peak Pricing Gulf Power's Experience*, Dan Merilatt, Goodcents Solutions, Inc. September 9, 2002

- Participants were generally very satisfied with the program and their bill savings were approximately 15% versus non-participants.

There are four key elements of Gulf Power's CPP program:

- ***Tariff:*** Time-varying rate design (low, medium, high and critical, timing varies by season and day-type);

- ***Technology:*** Customer programmed, automated energy management system / thermostat (customers can set the thermostat to whatever temperature they desire for each of the pricing periods). System can also control other major end-uses, such as water heaters;

- ***Communication:*** Mechanism to rapidly communicate rate changes and critical peak conditions to participants; and,

- ***Metering:*** Having an interval meter.

The four key elements are shown schematically in Figure 1. In the schematic, the telephone line provides consumption data from the interval meter back to the utility and the paging signal provides pricing information and (if appropriate) a curtailment signal to a "smart" thermostat at the customer's house. There are various other communications schemes available to achieve similar outcomes, but the key is that the communication must be two-way (both to and from customers). Within the home, the thermostat controls the HVAC system (air conditioner and furnace) and power line carrier is used to control other major loads such as water heaters and pool pumps.

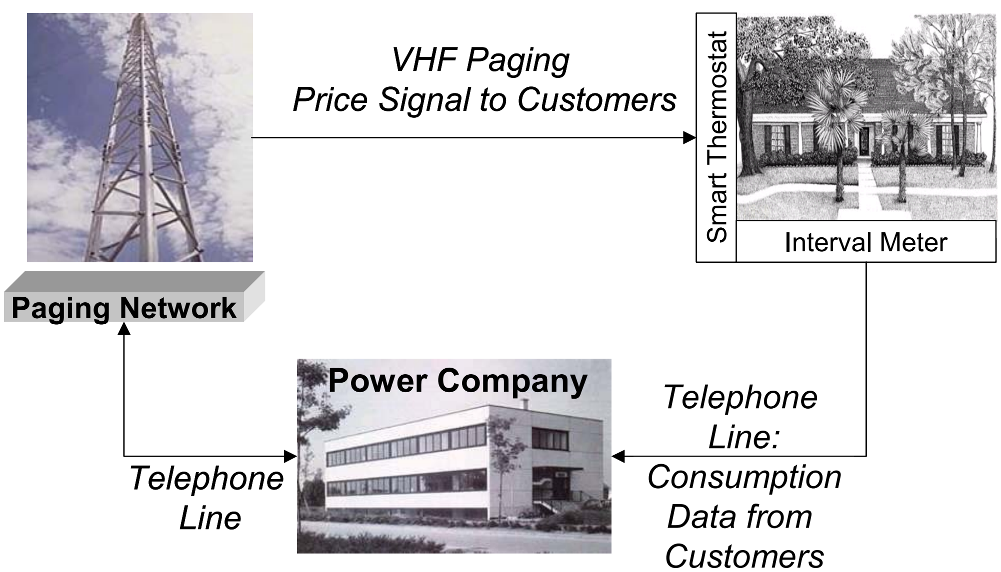


***Figure 2 – Schematic of Gulf Power CPP Information Flow***

Compared with standard TOU pricing, the key advantages of CPP programs are 1) automatic control of major household loads based on settings chosen by customers and 2) the ability to change prices dynamically during critical peak periods (and achieve greater demand reduction during these infrequent, but important, events). Together these advantages combine to allow customers to "set and forget", increasing demand response and satisfaction levels.

***EdF Tempo Rate is essentially a CPP rate***

Electricite de France (EdF) offers residential customers three rate options – a fixed rate, a standard TOU rate and a dynamic "tempo" rate[a]. Approximately 8 million EdF customers, roughly 1/3 of its residential customer base, are on TOU rates and 120,000 customers are on the *tempo* rate.

***…with the highest on-peak prices being fifteen times higher than the lower off-peak prices***

The *tempo* rate was introduced in 1993 and provides off-peak and peak rates for each of three day types – blue, white and red. Blue days are the most numerous ( ~ 300 per year) and offer the least expensive off-peak and peak rates. White days are the next most numerous (43) and offer mid-range rates. Red days are the least numerous (22) and offer the most expensive rates. The ratio of prices from the most expensive (red peak) to the least expensive (blue off-peak) is about 15:1 (this would be analogous to commodity costs ranging from $20 / MWh to $300 / MWh).

Customers are informed of the day-type (colour) for the next day through a variety of channels including the tempo website, an e:mail service, telephone, or an electrical device that can be plugged into any household socket.

## California Demand Response Initiatives

In response to a severe capacity shortfall in 2000/2001, California is pursuing demand response across a number of fronts. In July, 2002, the California Public Utilities Commission (CPUC) and California Energy Commission (CEC) adopted an Order Instituting Rulemaking[b] (the Order) designed to develop additional demand flexibility or response to increase reliability, lower purchased power and customer costs and protect the environment. Two significant initiatives flowing from the Order include:

- A State-wide Pricing Pilot of various TOU and CPP programs for small commercial and residential customers; and,
- Introduction of tariffs to encourage demand response among customers with peak demand > 200 kW.

These initiatives are different from the other ISO-based programs described previously in that they target commercial and residential customers exclusively.

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a *The Politics of Power Grids*, Asian Times On-line, Ahmad Faraqui, August 8, 2002

b *An Action Plan to Develop More Demand Response in California's Electricity Market*, P400-02-016F, California Energy Commission, July 2002

The comprehensive nature of these initiatives suggests that the results will serve as valuable input to increasing demand response cost-effectively within the Ontario market. Preliminary results and other information on these California initiatives will be available by the end of 2003.

***California experience will provide valuable lessons for Ontario***

### *Statewide Pricing Pilot for Small Commercial and Residential Customers*

A working group of industry participants and stakeholders found that previous research results regarding demand response among small commercial and residential customers indicated that:

***Factors affecting demand response among small commercial and residential customers***

- The highest level of demand response was associated with high-use residential customers with several appliances and access to automated control technologies in hot or cold climates under long-term programs.

- Lower levels of demand response were found among small commercial customers and low-usage customers with fewer appliances without access to automated control equipment in milder climates under short-term programs.

The working group also found that these results were subject to considerable uncertainty.

The $9.5 M US Statewide Pricing Pilot (SPP) is intended to address the most pressing questions related to capturing demand response among small commercial and residential customers. The primary objectives of the SPP are to:

***California pilots intended to answer the most pressing questions related to residential demand response***

- Estimate demand elasticities for key customer segments in response to three different time-varying and dynamic rates:
  - TOU
  - CPP with fixed duration critical pricing subject to day-ahead notification similar to EdF's *tempo* pricing, and
  - CPP with varying duration critical pricing and "day-of" notification similar to Gulf Power's CPP program.

- Develop demand curves that will allow utilities to generalize results from the pilot to estimate the expected level of demand response if the pilots were expanded to some or all of the small commercial and residential customer base, and

- Gather information on customer acceptance and opt-in or opt-out rates for different forms of dynamic rates, control technologies and information treatments.

The SPP is not intended to test customer response to incentives or "pay for performance" programs and hence could be considered to be "market-driven" to the extent that the pricing signals provided to customers are market-driven.

The impact of price on consumption is generally characterized in terms of elasticity. In simple terms, elasticity is defined as the percent change in consumption divided by the change in price. For example, with an elasticity of –0.2, a 10% increase in price would result in a 2% decrease in consumption (ie, 10% x –0.2 = -2%).

***Elasticity is % change in consumption divided by % change in price***

Elasticity estimates vary widely by segment (and within segments), but the following highlights provide some indication of "typical" elasticities and how they vary by segment and program:

***Residential TOU elasticity is typically –0.2, but could be double this under CPP***

- Residential customer peak period elasticities for TOU rates generally fall in the range of – 0.2. Note that 1) this figure applies only to participating customers, not all eligible customers, and 2) not all customers can be expected to participate in TOU programs if offered voluntarily (for example, only one-third of EdF's customer base participates in its TOU program).

- US residential customer peak period elasticities for dynamic pricing or CPP combined with enabling technologies such as automated thermostats have typically been double those for static TOU rates. This may also be a result of education, many utility residential TOU programs resulted in very small responses, but experiments showed that good advertising/customer education efforts significantly increased response.

- In Europe, residential customer elasticities are even higher. For example, peak period elasticities for the pilot program leading to EdF's tempo pricing were found to be –0.79, roughly in line with Swiss estimates of –0.6 during on-peak periods[a]. As with TOU rates, it is important to recognize that these estimates apply to participating customers, not all eligible customers. Also note that less than 1% of EdF's customers have chosen to participate in its *tempo* CPP program.

- Peak period price elasticity for small commercial customers is generally lower than residential customers, whereas for larger commercial customers with peak demand greater than 200 kW peak period elasticity is generally similar to, or higher than, that for residential customers.

- For rough comparison purposes, the elasticity of the participant group of large commercial and industrial customers from Georgia Power's RTP program is in the range of - 0.1 to - 0.2[b]. Given the unique characteristics of

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[a] *The Value of Dynamic Pricing in Mass Markets*, Ahmad Faraqui and Stephen S. George, The Electricity Journal, July 2002

[b] Individual customer elasticities ranged from – .01 to –0.40. Among individual segments for which data were available, implied elasticities were as follows: ~ - 0.1 for commercial office buildings; ~ - 0.05 for food products' manufacturers; ~ - 0.05 for schools and universities; and < - 0.05 for supermarkets.

the Georgia Power program (ie, consumption at the baseline is charged at standard rates), these elasticities are not directly comparable to elasticities of customers whose entire consumption was exposed to market prices.

***Cost-effectiveness of CPP program***

Analysis undertaken by PG&E determined that a CPP program would likely provide greater net societal benefits than a TOU program. The higher expected elasticity under a CPP rate structure drives the improved cost-effectiveness of these rate structures compared with standard TOU rates. Dynamic pricing provides the greatest demand response when it is needed (during critical peak periods) whereas TOU pricing provides some level of demand response when it might be needed (peak periods), but doesn't provide any opportunity for incremental response during critical peak periods.

***CPP net benefits range was negative $500 M US to positive $1 B US***

PG&E's analysis also indicated that the range of uncertainty surrounding the net benefits associated with a CPP program was significant and there was some chance it could provide a negative benefit (the range was negative $500 M US to positive $1 B US). The SPP will help to refine the cost/benefit analysis, program design and cost recovery mechanisms.

# MARKET-READY PRODUCTS AND SERVICES

***Interval meters, two-way communications and enabling technologies are market-ready***

The Gulf Power CPP program discussed in the previous section utilizes the key products and services necessary for demand response. As shown in Figure 3 and Figure 4, the key technologies and services are:

- Interval meters (to measure customer consumption every 15 minutes)
- Communication of metered consumption data to customer and LSE or LDC (as shown by the one-way telephone line)
- Communication of market price and need for demand response signal to the customer (as shown by the VHF Paging Price Signal to Customers)
- Ability of LSE and customer to execute desired response to end-use equipment (as shown by various in-house controls in Figure 4), and
- Feedback on actual response to customer, LSE/LDC and IMO/ISO (provided by the interval meter).

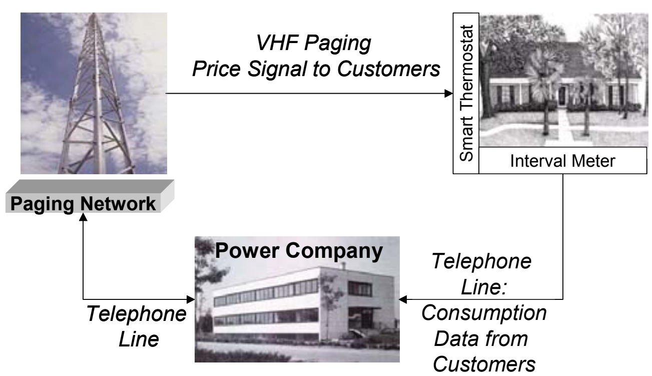
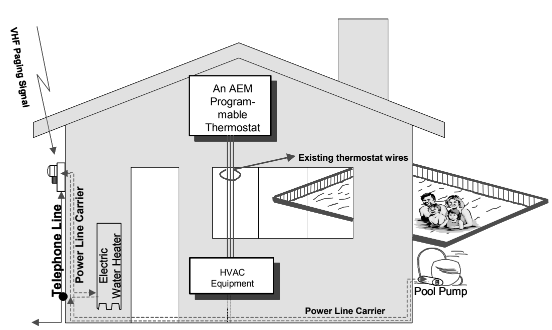



***Figure 3 – Illustration of External Products and Services to Enable Demand Response***

Figure 1 – In-House Enabling Technology for the Gulf State CPP program




Source: *Critical Peak Pricing Gulf Power's Experience*, Dan Merilatt, Goodcents Solutions, Inc. September 9, 2002

***Figure 4 – Illustration of Customer Facility Products and Services to Enable Demand Response***

A wide variety of technologies and options for each of these elements exist. In addition, numerous suppliers are packaging the above and other products into flexible, integrated service offerings for customers. As demand for these products increases, additional suppliers and service providers will enter the market. While there are some glitches with integrated solutions, technology is not the limiting factor for the development of large scale demand response programs.

***Technology is not the limiting factor for demand response***

However, caution must be exercised before selecting a specific technology or specific vendor for the following reasons:

***… but there is still a need for caution before choosing a particular "solution"***

- Technologies are developing at a rapid pace – some technologies are relatively new and may not have been fully tested.
- Although many suppliers are relatively large, stable companies, some are relatively small and may not survive.
- There are often different protocols and approaches for a given solution and there has not been any industry standardization in a number of areas. Certain promising technologies will come to dominate a particular segment, others will fade to obscurity. This is similar to the BETA versus VHS video recorder market situation in the 1970's and 1980's.
- Given the relative immaturity of many of these enabling products and services, it is likely that their prices will continue to decline into the future.

This suggests that a significant commitment to any "bleeding edge" solution could be relatively risky and potentially costly. A more prudent approach may be to either 1) pilot some of these "bleeding edge" solutions or 2) stick with relatively proven technologies from relatively stable companies for any significant technology commitment, although this approach may not capture all of the potential benefits that other, more innovative technologies could capture. There are risks in many of the technologies necessary to enable demand response and these risks should be borne by those best able to manage them.

Last, but not least, although these products and services are readily available, it will take time for customers to become sufficiently knowledgeable and comfortable to fully realize the potential demand response benefits. Given the necessary lead-time for customer and supplier education, a concerted education effort is needed to expedite and maximize demand response benefits available from these enabling products and services (it is not enough to simply install the technologies and expect customers and suppliers to fully utilize them).

***Customer and supplier education is critical***

Details on each of the primary enabling technologies and products for demand response are provided in the following sections.

It should be noted that the IMO would not likely be directly involved in either specifying or utilizing most of these technologies, but it is important for the IMO to understand how these technologies operate in order to facilitate integration with possible IMO demand response programs in the future. It is also important for the Government, the OEB, LDCs and other market participants to understand how these technologies operate and interact in order to inform decision-making with regard to changes in rules, codes and regulations to enable greater demand response in the Ontario market.

## Interval Meters

***Interval meters key enabling technology for greater demand response***

Interval meters are a key enabling technology for greater demand response by commercial and residential customers.

The standard "cumulative" meter used for residential customers typically has a number of counter-rotating dials measuring the customer's total energy consumption continuously from when the meter was installed. These meters are similar to the odometer in a car. They are typically read manually on a monthly or bi-monthly basis. The meter reading provides information on the total amount of energy the customer used in the period between meter reads, but doesn't provide any information as to when the customer used energy within the period between meter reads. Returning to the odometer analogy, cumulative meters only tell you how far the car was driven between meter readings, they don't tell you when the car was driven nor do they tell you how fast it was driven.

Interval meters measure a customer's energy consumption on a short time basis (typically 15 minutes or less). The detailed consumption data from an interval meter allows the IMO, LDCs and customers to get a better understanding of the customer's energy profiles over time. The data also allows the IMO and LDCs to accurately charge customers for their electricity based on usage in a given interval and the spot price for electricity in that same interval.

***Key questions for the IMO regarding interval meters***

While the IMO has established rigorous metering specifications for wholesale market participants, the IMO needs to consider the following questions with respect to interval meters and their influence on demand response:

1. Does metering for demand response have to meet the same standards applicable to large wholesale customers and generators?

2. Is revenue/settlement quality metering required to measure demand response?

The answers to these questions will have a significant influence on the IMO's ability to capture demand response among embedded LDC customers. Navigant Consulting believes that less rigorous standards would encourage greater demand response and would facilitate participation of embedded LDC customers in future IMO demand response programs.

In order to comply with the market rule that all existing customers > 1 MW have interval meters, Ontario LDCs have installed several thousand interval meters. These meters typically cost between $2000 and $3000 installed, including communications costs. The market rules also stipulate that new customers with expected peak demand > 500 kW must have interval meters installed.

***Key policy questions related to interval meters***

Questions that will also influence the level of demand response among embedded LDC customers include the following:

3. Should interval meters be made mandatory for other groups of LDC customers (eg, customers with demand > 200 kW and new homes)?

4. Will demand response be limited only to those customers with interval meters?

A brief discussion of factors relevant to the question of expanding the requirements for interval meters is provided below. With respect to limiting demand response to only those customers with interval meters, Navigant Consulting notes that there are a variety of proven mechanisms to accurately estimate demand response in certain niche applications (ie, direct load control) that do not require interval meters to be installed at all participating customers.

### *Installation of Interval Meters for > 200 kW Customers*

***California AB29x interval metering experience***

As part of AB29x legislation, California required advanced (interval) metering installed for all customers with demand > 200 kW[a]. This customer group represents approximately 30% of California's peak demand. Most customers with demand > 500 kW already had an interval meter, so the focus of the program was customers in the 200 kW to 500 kW range. The total program cost was $35 M US, and approximately 23,000 meters were installed at an average cost of $1500 US. Installation occurred over the period between July 2001 and June 2002. As part of the installation, all customers were provided with a password to view their energy usage, although installation of the communications links has lagged behind the meter installations.

Utilities were not required to implement TOU rates through AB29x, but most did. Hence, the situation for similarly-sized customers in California is essentially the opposite of those in Ontario – California customers are not exposed to market prices but have interval meters whereas Ontario customers are exposed to spot

[a] *Report to the Legislature on Assembly Bill 29x, Real Time Metering Program*, California Energy Commission, June 2002

prices, but do not have interval meters. The focus of the new tariff initiative is to encourage greater demand response for these customers through the use of CPP tariffs and other mechanisms, such as participation in the California Power Authority's (CPA's) Demand Reserves Partnership. The tariffs are intended to provide more cost- or market-reflective pricing to this customer group.

California realized significant peak load reductions of 7% to 10% during the summer of 2001, a portion of which is attributed to the interval meter program. A more comprehensive evaluation study estimating the impact of this interval metering program during the summer of 2002 was due in March 2003.

***Extrapolating the California experience to Ontario***

If Ontario policy makers choose to implement a similar metering policy as in California, Navigant Consulting estimates that it would require approximately 10,000 interval meters to cover all customers > 200 kW in Ontario[a]. Assuming an installed cost of $2,000 per meter, this would cost approximately $20 M.

Implementation of this policy would allow customers representing more than 10% of Ontario's electricity market volume that are already exposed to wholesale market prices (excluding those designated customers that are on the fixed 4.3 cents/kWh retail price) with the capability to manage their electricity costs by managing their demand.

***Cost-effectiveness of mandatory interval meters > 200 kW***

A simple economic model was developed to explore, at a high level, the cost-effectiveness of such a policy. The model is based on estimates of incremental monthly metering costs for the interval meters and estimates of the overall price elasticity of the entire population of affected customers. Based on an installed cost of $2000 per meter, a fifteen year meter life and a 10% cost of capital, the annualized capital costs for the interval meters would fall in the range of $20 to $25 per month. Incremental costs for data management are expected to fall in the range of $5 to $10 per month[b], for a total incremental cost of perhaps $25 to $40 per month. In estimating price elasticity, it is important to recognize that most elasticity estimates represent the response of voluntary and willing participants who were free to choose whether or not to participate. Assuming that installation of interval meters for customers > 200 kW will be mandatory and recognizing that not all customers will respond as favourably as voluntary participants, Navigant Consulting believes that elasticity estimates would likely fall towards the low end of published data. Hence, a group elasticity in the range of –0.05 to –0.1 would be reasonable (some customers would exhibit higher elasticities, whereas other customers would exhibit zero elasticity). Navigant Consulting also assumed that

[a] Some Ontario customers with peak demand < 1 MW have already installed interval meters at their own costs, presumably to take advantage of a favourable load profile and/or demand response capabilities.

[b] Some LDCs have reported data management costs greater than $10 per meter per month, but Navigant Consulting expects that, given the expected volumes, the incremental costs of data management for additional interval meters would be $10 per meter per month or less.

the maximum demand reduction from this customer group would represent 10% of their peak demand and that the threshold price at which customers would exhibit elasticity effects would be $100 / MWh. Based on these assumptions and using Ontario wholesale market prices from May 1, 2002 and assuming a customer with a peak demand of 200 kW and a load profile similar to Toronto Hydro's net system load shape, the expected benefits for different incremental interval metering costs and group elasticities are provided in Table 2. The most likely range based on current metering costs and expected elasticities is highlighted.

***Table 1 – Estimated Monthly Benefits for Installing Interval Meters at a 200 kW customer***

| | Monthly incremental interval metering cost (unit cost amortized over 15 years plus operational costs) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Elasticity | $10 | $15 | $20 | $25 | $30 | $35 | $40 | $45 | $50 | $55 | $60 |
| -0.025 | $39 | $34 | $29 | ***$24*** | ***$19*** | ***$14*** | ***$9*** | $4 | -$1 | -$6 | -$11 |
| -0.05 | $89 | $84 | $79 | ***$74*** | ***$69*** | ***$64*** | ***$59*** | $54 | $49 | $44 | $39 |
| -0.075 | $129 | $124 | $119 | ***$114*** | ***$109*** | ***$104*** | ***$99*** | $94 | $89 | $84 | $79 |
| -0.1 | $156 | $151 | $146 | ***$141*** | ***$136*** | ***$131*** | ***$126*** | $121 | $116 | $111 | $106 |
| -0.125 | $178 | $173 | $168 | $163 | $158 | $153 | $148 | $143 | $138 | $133 | $128 |
| -0.15 | $198 | $193 | $188 | $183 | $178 | $173 | $168 | $163 | $158 | $153 | $148 |
| -0.175 | $215 | $210 | $205 | $200 | $195 | $190 | $185 | $180 | $175 | $170 | $165 |
| -0.2 | $230 | $225 | $220 | $215 | $210 | $205 | $200 | $195 | $190 | $185 | $180 |

This simple analysis suggests that installation of interval metering would likely be cost-effective for customers > 200 kW, provided the incremental costs were less than $50 per meter per month and the overall elasticity of the customer group as a whole was –0.025 or less (ie, more negative). In considering these results, it is important to recognize that:

***Other considerations for interval meters for > 200 kW customers***

- Larger customers and customers that are more price-responsive would experience greater benefits since the costs of metering would not be expected to vary with customer size.

- This analysis does not consider the cost of other enabling technologies such as an automated remote control services or mechanisms to provide the necessary price signal to customers and / or their service providers.

- Elasticity would likely increase with customer experience, but the time frame over which this increase would occur is uncertain.

- If market prices are lower and/or less volatile than they have been since market opening on May 1, 2002, the benefits would be lower.

***Assuming 100 MW of demand response, prices would have been 0.5% lower, representing savings to all customers of $51 M***

The preceding analysis does not reflect the benefits to the entire market due to the reduction in wholesale market prices that would accrue from the demand response from this group. As discussed in *Valuing Demand Response* on page 56, assuming this customer group contributed demand response of 100 MW when market prices were above $150/MWh, the overall cost of electricity in Ontario would have been reduced by 0.5% or $0.32 / MWh since market opening, representing consumer savings of $51 M. This is much greater than the estimated cost of $20 M to install the meters.

Installation of interval meters for customers > 200 kW will also mitigate the level of "subsidy", if any, either to or from this customer group from other customers, such as low volume customers under the 4.3 cents/kWh retail rate freeze, within each LDC's Net System Load Shape. Thus, based on the load shape of the customers > 200 kW vis-à-vis other NSLS customers, the total cost of the Government's obligation under the retail rate freeze could either increase, decrease or remain essentially the same after installing interval meters.

***Installing interval meters would also eliminate any subsidies to or from smaller customers on the NSLS***

### *Small Commercial and Residential Customers*

Based on discussions with Milton Hydro, a local Ontario LDC, and OZZ Corporation, an Ontario energy technology and services company, interval meters for residential customers are reported to cost between $300 and $400 per meter under the terms of Milton Hydro's interval metering pilot program. The high end of the range would reportedly include a module able to integrate and communicate interval data from electric, water and gas meters whereas the low end of this range would include interval data capabilities for an electric meter only. Meter reading and data management is provided by OZZ Corporation which provides "bill ready" data to Milton Hydro. While the Milton Hydro program is targeted to new homes, existing residential customers can also request interval meters, but must pay $5.50 per month for the meter and associated web-access services. Milton Hydro has also implemented a policy requiring interval meters for existing customers with peak demand > 50 kW and all new customers.

***Residential interval meters reported to cost $300 to $400 each in Ontario***

For larger scale deployments, costs would be expected to drop significantly. Recent analysis done by PG&E[a] in California suggests that advanced (interval) meters could cost as little as $100 US/meter each, based on 8 million meters (4.7 million electric meters and 3.3 million gas meters) covering approximately 90% of PG&E's customers below 200 kW deployed over a five year period starting in 2004. PG&E's analysis does not include the costs of any additional customer-side enabling technologies (eg, smart thermostats or controls).

***… but would likely drop to $100 US per meter for large volume deployments of more than one million meters***

In addition to the cost of the meters themselves, other forecast costs (all figures in US $) that would be incurred over PG&E's 15 year analysis period include:

- $242 M for network equipment (approximately $30 US/meter in presumably up-front costs);
- $735M (present value) for network and data services (such as communications and data management), representing approximately $1 per month per meter; and,
- $86 M (present value) for other costs.

[a] *Proposed Pilot Projects and Market Research to Assess the Potential for Deployment of Dynamic Tariffs for Residential and Small Commercial Customers,* Report of Working Group 3 to Working Group 1, R.02-06-001, Final Version, December 10, 2002

The majority of PG&E's forecast savings were in normal and special meter reading costs – $558 US M over 15 years, representing approximately $0.75 US / meter / month. Note that PG&E has a higher customer turnover rate than most Ontario utilities, so the cost savings from special meter reads would probably be less for Ontario utilities. Other minor savings due to fewer erroneous high bill complaints, improved field operations and better system planning (eg, optimal transformer sizing) were included in the analysis.

Given the number of LDCs in Ontario, it is unlikely that this level of costs could be achieved for a large scale deployment of interval meters among small commercial and residential customers in Ontario in the near term unless there was significant co-ordination between LDCs.

Based on this information, Navigant Consulting expects that short to medium term costs for residential interval metering are more likely to fall in a range between that currently experienced in Ontario for relatively limited deployment ($300 - $400 Cdn / meter) and those projected by PG&E for a large scale deployment ($150 Cdn / meter). Over time as the technology develops and production volumes increase (perhaps through a mandatory deployment in California), the long term costs for large scale interval meter deployment would probably fall to or below the lower end of this range.

***Cost-effectiveness model for interval metering of new homes***

Using a similar high-level economic model as described above for the > 200 kW customer group, Navigant Consulting explored the cost-effectiveness of a policy of mandatory interval metering for new homes. The model is based on estimates of incremental monthly metering costs for the interval meters and estimates of the overall price elasticity of the entire population of affected customers. Based on an installed cost of $400 per meter, a fifteen year meter life and a 10% cost of capital, the annualized capital costs for the interval meters would fall in the range of $4 to $5 per month. Incremental costs for data management are expected to fall in the range of $2 to $4 per month, for a total incremental cost of perhaps $6 to $9 per month under current market conditions and with current market pricing. As with the estimate of demand response for customers > 200 kW, it is important to recognize that most elasticity estimates represent the response of voluntary and willing participants who were free to choose whether or not to participate. Assuming that installation of interval meters for new homes was mandatory and recognizing that not all customers will respond as favourably as voluntary participants, Navigant Consulting believes that the overall elasticity of the customer group would likely fall towards the low end of published data. Hence, group elasticities in the range of –0.05 to –0.1 would be reasonable (some customers would exhibit higher elasticities, whereas other customers would exhibit zero elasticity). Navigant Consulting also assumed that the maximum demand reduction from this customer group would represent 40% of their peak demand (consistent with experience in the GulfPower CPP pilot) and that the threshold price at which customers would exhibit elasticity effects would be $70 / MWh.

| Elasticity | Monthly incremental interval metering cost (unit cost amortized over 15 years plus operational costs) $1 | $2 | $3 | $4 | $5 | $6 | $7 | $8 | $9 | $10 |
|---|---|---|---|---|---|---|---|---|---|---|
| -0.025 | $0.18 | -$0.82 | -$1.82 | **-$2.82** | **-$3.82** | **-$4.82** | **-$5.82** | -$6.82 | -$7.82 | -$8.82 |
| -0.05 | $1.23 | $0.23 | -$0.77 | **-$1.77** | **-$2.77** | **-$3.77** | **-$4.77** | -$5.77 | -$6.77 | -$7.77 |
| -0.075 | $1.86 | $0.86 | -$0.14 | **-$1.14** | **-$2.14** | **-$3.14** | **-$4.14** | -$5.14 | -$6.14 | -$7.14 |
| -0.1 | $2.38 | $1.38 | $0.38 | **-$0.62** | **-$1.62** | **-$2.62** | **-$3.62** | -$4.62 | -$5.62 | -$6.62 |
| -0.125 | $2.80 | $1.80 | $0.80 | -$0.20 | -$1.20 | -$2.20 | -$3.20 | -$4.20 | -$5.20 | -$6.20 |
| -0.15 | $3.12 | $2.12 | $1.12 | $0.12 | -$0.88 | -$1.88 | -$2.88 | -$3.88 | -$4.88 | -$5.88 |
| -0.175 | $3.40 | $2.40 | $1.40 | $0.40 | -$0.60 | -$1.60 | -$2.60 | -$3.60 | -$4.60 | -$5.60 |
| -0.2 | $3.64 | $2.64 | $1.64 | $0.64 | -$0.36 | -$1.36 | -$2.36 | -$3.36 | -$4.36 | -$5.36 |

***Table 2 – Estimated Monthly Benefits for Installing Interval Meters at a New Home with a Diversified Peak Demand of 3 kW***

Based on these assumptions and using Ontario wholesale market prices from May 1, 2002 and assuming a customer with a diversified peak demand of 3 kW and a load profile similar to Toronto Hydro's net system load shape, this simple analysis suggests that installing interval meters at new homes would not be cost-effective unless incremental costs were less than $4 per meter per month and the overall elasticity of the customer group was less than than –0.1 (ie, less negative). In considering these results, it is important to note that:

***Considerations regarding interval meters for new homes***

- Larger homes with higher electricity consumption would be expected to experience greater benefits since the costs of metering would not vary with consumption whereas the potential cost savings would.

- Smaller homes and homes without air conditioning (such as those in Northern Ontario) would realize less benefits.

- This analysis does not consider the cost of other enabling technologies such as a smart thermostat or mechanisms to provide the necessary price signal to customers and / or their service providers.

- Elasticity would likely increase with customer experience, but the time frame over which this increase would occur is uncertain.

***With interval meters on 75,000 new homes, prices would have been 0.3% lower, representing savings to all customers of $26 M***

Also, note that this analysis does not reflect the benefits to the entire market due to the reduction in wholesale market prices that would accrue from the demand response from this group. As discussed in *Valuing Demand Response* on page 56, assuming the approximately 75,000 new homes constructed in Ontario each year had interval meters and that these customers contributed demand response of 50 MW whenever market prices were above $150/MWh, the overall cost of electricity in Ontario would have been reduced by 0.3% or $0.16 / MWh since market opening, representing savings of $26 M.

The level of uncertainty regarding the cost-effectiveness of interval metering for residential customers is consistent with recent analysis by PG&E. PG&E's analysis identified a financial gap between the costs of large scale deployment and the saving realized of $1,080 US million, roughly $2 / electric meter / month. This essentially represents the gap that would have to be made up from benefits associated with demand response or other benefits not captured in PG&E's analysis.

In contrast to the financial gap identified in PG&E's analysis, two major US utilities have implemented advanced metering technology on a large scale without consideration of potential demand response benefits and the information benefits for customers[a]. Puget Sound Energy (PSE) and Pennsylvania Power and Light (PP&L) , with more than 1.5 million and 1.3 million meters deployed, reported economic payback periods of between 6 and 9 years for their deployment. This suggests that these two utilities' actual deployment and expected operational costs were significantly lower than PG&E's estimates and/or their expected savings were significantly higher than PG&E's estimates. Regardless, although there may be some level of certainty and agreement on deployment costs, there is considerable uncertainty regarding the actual operating costs and benefits of advanced metering systems.

***Potential demand response benefits from CPP/TOU Pricing for PG&E***

PG&E's analysis of the potential demand response benefits (Total Resource Costs) ranged from $561 US M to $2,637 M, as shown in Table 3. As with the high level estimate for Ontario discussed previously, PG&E's analysis does not include the costs of any customer-side enabling technologies, such as smart thermostats, that would enhance demand response. Note that the PG&E analysis suggests there are significant T&D benefits from CPP/TOU pricing (assuming persistent load shifting occurs) and that lost revenues from CPP/TOU pricing could be significant. Given the generation mix in Ontario, the relative energy and capacity benefits would likely be different for Ontario, but would still be highly uncertain. Also, whether Ontario LDCs would experience the same level of T&D benefits and lost revenues is unknown.

***Table 3 - Combined benefits of CPP/TOU Pricing for PG&E ($ M US)***

| | ***A) Energy and Capacity Related TRC Benefits*** | ***B) T&D Related TRC Benefits*** | ***C) Total TRC[b] Benefits (A+B)*** | ***D) Lost Revenue*** |
|---|---|---|---|---|
| Low Case | $418 | $143 | **$561** | $316 |
| High Case | $2,298 | $339 | **$2,637** | $923 |

[a] Summary Report of Experiential Workshops, Day 1, September 9, 2002, Dynamic Pricing, Tariffs and Price Responsive Demand Programs, CPUC OIR R-02-06-001

[b] TRC = Total Resource Costs. This is a measure of the net societal benefit from a given program, typically a demand-side management (DSM) program. It represents that expected societal savings over the lifetime of the programs and the measures installed, less the total societal costs for implementing the program. This same test is currently used by Ontario gas utilities to screen potential DSM programs.

When the estimated demand response benefits from the PG&E analysis are compared to the interval metering "financial gap" of $1,080 US million, the overall benefits of deploying advanced metering could range from:

***Estimated total benefits for PG&E interval metering program range from negative $500 M US to positive $1,500 US M***

- negative $500 US million (ie, the negative $1,080 million gap from deployment of advanced metering plus the $561 US million low case TRC for CPP/TOU pricing), to

- positive $1,500 US million (ie, negative $1,080 million gap plus the $2,637 US million high case TRC for CPP/TOU pricing).

This uncertainty is one of the primary reasons behind the Statewide Pricing Pilot. The pilot is intended to firm up the benefits of dynamic pricing to inform decision-makers and policy-makers.

Together, the high level analysis undertaken by Navigant Consulting and the results of PG&E's analysis highlight the need for caution in mandating interval meters for small commercial and residential customers.

***Need for caution in mandating interval meters for new homes***

## Communications

The required communications for a fully developed demand response program include mechanisms to:

***Key communications elements for fully-develop demand response program***

- Send current consumption data to the end-users, LDCs and demand response aggregators;

- Receive the price and/or reliability event signal;

- Communicate the price/event signal to the end-user and/or their control systems; and,

- Confirm that the demand response occurred.

Technologies and approaches for each of these communications links exist. In the past, demand response programs may not have included all of these links, certainly not in real-time. Integrated communications solutions using the Internet are becoming the wave of the future.

There are a wide variety of communication methods available for getting data from interval meters and/or providing signals to remote controls and other equipment at customers' facilities. These include

***Wide variety of communication methods available***

- Digital Paging
- Telephone Landline
- Cellular Telephone
- Radio Frequency

- Satellite, and
- Power Line Carrier.

Navigant Consulting understands that customers' telephone landlines (primarily shared, but occasionally dedicated) are the primary means for communicating wholesale and retail interval meter data back to LDCs in Ontario.

In addition to these communications technologies listed above, some utilities are using what is referred to as an internet gateway. Navigant Consulting expects that the internet gateway is the most important development in enabling cost-effective two-way communications for demand response. While these gateways are relatively expensive today (approximately $500 US/unit), their costs will drop significantly over time and they will likely become the primary communications hub for demand response programs in the future due to their expected low cost, ubiquitous availability, platform independence, flexibility, and ability to link end-users, LDCs, demand response aggregators, system operators, meters, and end-use equipment.

***Internet gateway will become demand response communications hub in the future***

## Direct Load Control

Direct load control technologies control customer loads and equipment directly with minimal, if any, opportunity for customer over-ride. Many Ontario MEUs used radio frequency or power line carrier communications to remotely control water heaters at customers' houses. Several US utilities offer air-conditioner cycling programs using similar control devices. With the growth in wireless communications networks, paging has become a more common means of providing direct load control signals with relatively low costs per point.

***Many Ontario MEUs remotely controlled customer water heaters***

These and other direct load control technologies have continued to evolve since they were first introduced and there are a wide range of choices with varying levels of functionality available at various price points. Industry sources indicate that the typical costs per point are in the range of $80 to $100 (excluding the cost of the central control system and communications infrastructure). There are reports of residential control devices in the UK costing less than $20 per point (excluding installation and communications infrastructure costs).

***Residential control costs expected to range from $20 to $100 per point, plus central infrastructure costs***

Building control and energy management systems have been available for commercial facilities for over fifteen years. These systems monitor and operate building systems to maintain temperature, humidity, lighting levels and other building parameters. These systems allow central control of all major building equipment and so, are a natural "gateway" for direct load control, with the most significant cost often associated with integrating the remote control signal with the building control system.

***Commercial building control and energy management systems have been available for over fifteen years***

Given their extensive use, building control systems represent an important enabling technology for either direct load control by suppliers or customer response to external pricing signals. Multiple vendors have packages that can receive the price/event notice from the ISO, send a signal to the control equipment based upon user specifications, monitor the load reduction, and communicate the results back to the end-user and/or their demand response aggregator.

## "Smart" Thermostats and Controls

***"Smart" thermostats respond to external pricing or curtailment signals***

"Smart" thermostats combine a communications module with a conventional setback thermostat that responds to an external pricing or curtailment signal according to the customer's choices. For example, a customer could set their smart thermostat to 25 $^{o}$C during "normal" pricing periods during the summer and 28 $^{o}$C during "high" price periods. A neighbour might set their thermostat to 26 $^{o}$C for normal pricing periods and 27 $^{o}$C for high price periods. Similarly, customers with electric water heating or pool pumps could program their water heater or pool pump not to operate during high price periods.

There are reportedly a half dozen thermostat suppliers vying to offer "smart" thermostats and many of these and other suppliers are collaborating with load control and home automation suppliers. These devices are reportedly available for approximately $50 to $70 US in large volumes based on information provided during California's recent investigation of demand response potential within the State.

Internet gateway boxes with switches for connections for multiple services such as cable, internet and telephone would enable either direct load control or signals for smart appliances. Given their complexity, these devices cost more than "smart" thermostats, but also provide greater functionality. These can be configured to connect disparate equipment such as energy management systems, internet connections and load control relays and switches.

***Thermal energy storage can facilitate load shifting***

Although thermal energy storage technologies do not facilitate response to dynamic price signals (eg, a single hot day during the summer), they do facilitate load shifting. Hence, these technologies could also be used to mitigate periods of high demand by encouraging customers to shift consumption from peak periods to off-peak periods.

## Services

***Services to leverage enabling technologies***

There are a variety of complementary services available from suppliers to leverage the enabling technologies described above. Service providers are responding creatively to market mechanisms and rules and are using enabling technologies to create significant benefits for customers.

Navigant Consulting is aware of one Ontario retailer that has worked closely with a multi-site customer to centrally manage demand at the retailer's facilities in response to price signals. There are likely several other local examples of service providers offering similar services.

***Examples of innovative demand response services***

ConsumerPowerlines in New York provides some interesting examples of what services providers can do. For example, ConsumerPowerlines aggregated the consumption of public schools in New York. During curtailment events students and faculty vacated and turned off load in their offices and classrooms. ConsumerPowerlines also aggregated the tenants in an apartment complex and offered free passes to a local theatre if customers committed to turning off all non-essential equipment when they leave. The movie theatre ticket stamps serve as verification that customers participated. The apartment's main interval meter accurately records the customers' aggregate demand response.

With the proper market rules and enabling technologies, the same level of creativity would be expected to become readily available in the Ontario market.

# RESOURCES PRIOR TO MARKET COMMENCEMENT

There were three primary types of demand response "programs" or resources within Ontario prior to market commencement:

***Three primary types of demand response "programs" prior to market opening***

- Interruptible programs offered to direct customers by Ontario Hydro
- Load controlled water heaters, and
- Load control programs offered by local municipal utilities.

These programs are discussed in the following sections.

## Previous Ontario Hydro Interruptible Tariffs

Ontario Hydro offered interruptible tariffs in the 1980's and 1990's to certain large price-sensitive industrial customers. These tariffs, such as the discount demand service tariff, provided reduced energy and demand rates in exchange for the utility's right to occasionally interrupt service during periods of high demand or supply deficiency. The interruptible capacity contributed towards reserve margins, but interruptions were very infrequent during most of this period.

***Ontario Hydro reported to have had 1100 MW of interruptible load in the 1980's and early 1990's***

In the 1980's and early 1990's, Ontario Hydro is reported to have had about 1100 MW of interruptible load under contract. Because of load factors, about 600 – 700 MW of this interruptible capacity was actually available when needed. In the mid-1990's, Ontario Hydro started to phase out or transition customers off many of its interruptible rate offerings towards other tariff offerings that were more reflective of the supply situation and the underlying benefits provided.

***Many subsequent offerings were essentially economic development tariffs***

Entering market opening, Ontario Power Generation (OPG) had power supply contracts with approximately 80 large industrials. These contracts were called Real Time Pricing ("RTP") RTP I, RTP II, surplus load and load retention and expansion price offerings. Most contracts were signed to either increase Ontario demand or to support economic development initiatives. These contracts were essentially a competitive response to the competition posed by utilities in the other jurisdictions that the customer was considering locating or expanding its facilities into. As such, most of these rates could be viewed more as economic development rates rather than as interruptible rates.

The IMO's estimate of the amount of dispatchable load that would be available at market opening was 600 MW. Navigant Consulting believes that there was about 450 MW of interruptible load just prior to market opening. Based on these two independent estimates, available interruptible capacity was likely in the range of

400 – 600 MW at market opening. Accessing this capacity is highly dependent on program structure and incentives.

Two issues associated with "reactivating" this capacity are:

***May be difficult to fully "reactivate" this capacity without some fixed incentive***

- Most interruptible customers were given a rate discount (effectively a fixed payment) to participate, whereas most demand response programs currently being considered do not incorporate such fixed payments. Hence, the same level of demand response may not be achievable with the programs currently under consideration.

***…but some customers are probably already participating in the IMO's Emergency Demand Response Program***

- Many of these customers who signed up for Ontario Hydro's interruptible tariffs did so with the expectation that interruptions would occur rarely and only as a last resort. Many of these same customers are probably willing to participate in an emergency demand response programs (indeed, many are likely already participating in the IMO's EDRP), but may not participate in an market price-based or economic DR program if they are not interested in altering their business operations to play in the commodity markets.

## Load Control Programs Offered by Local Municipal Utilities

***Surveyed more than 20 LDCs regarding their previous load control programs***

To get a better understanding of load control programs offered by local municipal utilities before market opening, Navigant Consulting sent a survey to over twenty Ontario LDCs. The sample comprised large LDCs and some smaller LDCs that were known to be particularly interested in demand response. Hence, the results should not be taken as representative of the entire population of LDCs. However, the results do provide a good indication of what load control programs were offered and what might be reasonably achievable in the future provided critical issues raised by respondents can be overcome. Given the sample and potential response bias, Navigant Consulting believes that the results for the entire population of LDCs in Ontario would likely represent between one and a half to two times the respondent results given below.

Thirteen LDCs, representing 1.6 M customers or roughly 40% of LDC customers, responded to the survey. Twelve of the respondents offered rental water heaters in the last five years and ten respondents (or their affiliates) still offer rental water heaters. The respondents reported that 16% of their residential customers have electric water heaters (approximately 260,000 electric water heaters) and approximately 222,000 of these are rental water heaters. These results are shown schematically in Figure 5.

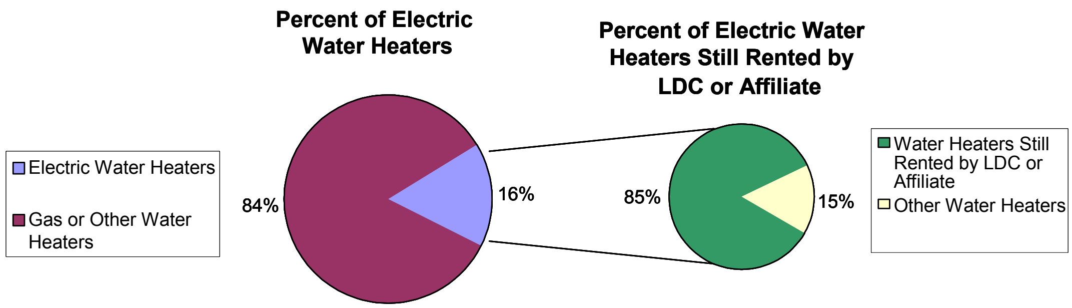



***Figure 5 – LDC Water Heater Rental Situation***

***LDC water heater load control programs***

Seven of the respondents reported offering load-controlled rental water heaters in the last five years, and two respondents reported offering load-controlled water heaters more than five years ago (the responses of these two LDCs were not considered in our analysis). Based on the survey responses, approximately 84,000 water heaters were load-controlled at some point in the last five years. Five of the seven LDCs used a centrally-dispatched signal to control the water heaters; the other two used individual timers. Among the LDCs reporting the use of a centrally-dispatched signal, there were two distinct control philosophies employed. Three LDCs turned off water heaters only at hours of highest demand (15 to 20 hours per month) and two LDCs turned off water heaters for several hours every weekday (140 to 160 hours per month).

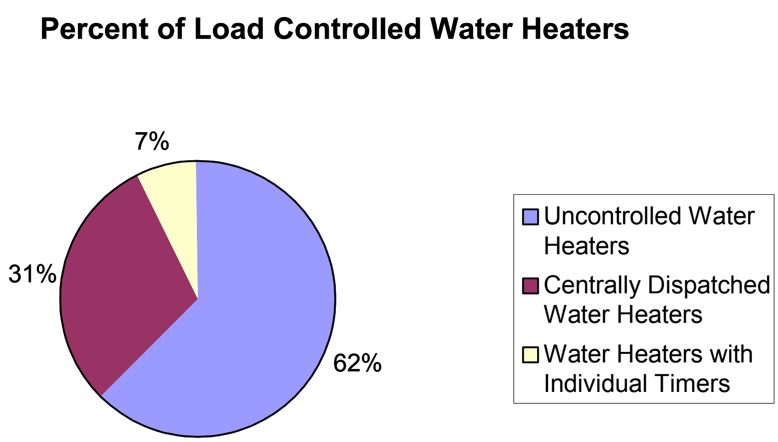



***Figure 6 – Breakdown of Water Heater Load Control Schemes***

Incentives for participating customers averaged $5/month, with a range of $0/month to $8/month. In most cases, the incentive was roughly equal to the rental cost of the water heater, hence the net rental cost for participating customers was zero.

LDCs reported that individual water heaters represented a range of 0.5 kW to 3.2 kW in demand reduction. Since not all water heaters are on at the same time and assuming an average annual load of 5000 kWh for a water heater, an estimate of the diversified demand in the range of 0.5 kW to 0.8 kW per water heater is reasonable (diversified demand would be towards the high end of this range in the early morning after customers had showers and in the early evening after dishwashing and bathing). Navigant Consulting estimates that there was approximately 45 MW to 67 MW of total demand reduction from the seven respondents that offered water heater load-control programs.

***Estimated reactivation costs of $20 per water heater***

Only one LDC offers load-controlled water heaters today, but the other six LDCs reported that they have the infrastructure in place. Among those utilities with the infrastructure still in place, Navigant Consulting estimates that the reactivation cost is likely to be $20 per water heater. This cost would likely cover communicating with customers, establishing the necessary customer billing information and ensuring the central control system was still operational. If the LDC needed to test each individual control to ensure it was still operational, the costs would be significantly higher. However, assuming that most of the controls are operational, individual testing may not be cost-effective in the short term (ie, for summer 2003).

In considering whether these potential demand response resources can be cost-effectively reactivated, it is important to recognize that the water heaters are typically owned by the LDC's competitive affiliate but the individual controllers and central control system may be owned by either the LDC or its competitive affiliate. Hence, reactivation of this demand response resource would likely involve both the LDC and its affiliate, which could complicate cost allocation and recovery issues.

***Need daily load shifting to reap maximum benefit from water heater load control***

High level analysis by Navigant Consulting indicates that a direct load control strategy of shutting off water heaters during the eight most expensive hours every day (eg, between 2 pm and 10 pm) would reduce the commodity cost for a typical electric water heater by between $50 and $80 each year. Note that this control strategy includes the benefits from demand response during high priced periods, plus the benefits from daily load shifting.

***100,000 load controlled water heaters could have reduced overall cost of electricity by $50 M***

Assuming 100,000 water heaters representing approximately 70 MW of demand response had been operated under the strategy described above since market opening, Navigant Consulting estimates that the overall cost of electricity in Ontario would have been reduced by 0.3% or $0.31 / MWh, representing consumer savings of approximately $50 M.

Less aggressive strategies would simply shift consumption to marginally less expensive periods and would not generate the same level of savings. For example, a daily load shifting strategy of shutting off the water heaters during the three most expensive hours would simply delay the energy that would have been consumed during these three hours to the following three hours which are typically not significantly less expensive. Based on Navigant Consulting's modeling, this strategy would only reduce participant's commodity costs by between $7 to $10 each year. However, the overall reduction in the cost of electricity in Ontario could still be significant.

While water heaters are attractive loads to control given their thermal mass, the water heater load is not always coincident with the system peak. Direct control of air-conditioners would probably be more cost-effective because air-conditioning load will be coincident with the system peak (and high prices) during summer periods. Navigant Consulting believes that LDCs and other market participants should target air-conditioners in future direct load control programs. As discussed in *Direct Load Control* on page 10, several utilities have successfully offered air conditioner load control programs for many years.

***LDCs and aggregators should also target direct control of air conditioners in the future***

## Other Demand Response Programs Offered by LDCs

Twelve LDCs responded to survey questions related to other demand response programs they previously offered. Of these, four LDCs offered other demand response programs. For three of the respondents, the primary reason for these programs was to manage their peak demand charges. The other LDC implemented programs to manage a capacity limitation at a transformer station and defer network upgrade costs[a].

***Some LDCs offered peak demand management programs to their larger customers***

Programs offered included offering customers a discount demand charge in return for demand reduction in a voluntary load reduction program; interruptible and curtailable rates and the use of load displacement generators; community awareness campaigns; and highly localized voltage reduction.

These programs were reported to provide between 10 MW to 12 MW of load reduction. However, it is questionable how many customers would still be available or willing to participate. One LDC reported that one of its customers that had previously participated had become a wholesale market participant and several others were designated customers, subject to the 4.3 cents/kWh retail price freeze.

## Additional Feedback and other Issues Raised by LDCs

Twelve LDCs responded to survey questions on other issues related to demand response. Among the key findings from the survey:

- Approximately 25% of LDC load serves customers with interval meters. Assuming that LDC load represents 80% of market volume and that all wholesale market participants representing 20% of market volume also have interval meters, this suggests that over 40% of Ontario load is measured using interval meters.

***Feedback from LDCs suggests that over 40% of Ontario load is served by interval meters***

[a] In certain situations, the deferral of major capital expenditures for network upgrades could represent a significant portion of the savings from demand response programs.

- Eight of the respondents reported using the OEB-mandated thresholds for interval meters (ie, 1,000 kW for existing customers and 500 kW for new customers). Three of the respondents have a 500 kW threshold for both new and existing installations. One respondent has a 300kW threshold for both new and existing installations. Milton Hydro has implemented a policy requiring interval meters for existing customers with peak demand > 50 kW and all new customers.

- Other than street lighting, no unique customer segment load profiles were used for billing.

***No LDCs have implemented unique load profiles, other than for street lighting***

- All LDCs charge customers a fixed wholesale market service charge (WMSC) to recover IMO fees, uplift and other wholesale market charges. Although respondents were not asked, Navigant Consulting expects that most LDC's WMSC is $5.2 / MWh as suggested by the OEB. The implications of this fixed charge (versus a dynamic charge) on demand response are discussed in *Averaged Wholesale Market Services Charges* on page 52.

***Key impediments to LDCs participating in demand response initiatives include cost recovery and frozen retail prices***

LDC's primary concern with respect to participating in any future demand response initiatives was recovery of the associated capital, operating and marketing costs. As stated by one respondent:

> *"LDC's do not have the financial resources available for DSM Programs. In addition to the additional costs of actually running the program is the cost of advertising and supporting customer calls related to the programs. These costs cannot be ignored when reviewing the impacts on an LDC entering into such programs."*

The lack of any meaningful (market-based) customer incentive under the current retail rate freeze was cited by all respondents.

Other issued identified were:

- Staffing-related (limited staff and/or expertise)
- Regulatory-related
- "Not currently part of mandate from OEB"
- Red tape - Requirement of ministry approval for any rate increase (necessary to recover costs)
- "No guarantee such programs would be accepted in rate applications"

One LDC raised the issue of potential billing complexities and another highlighted the perceived loss of income to retailers from any changes to NSLS. Navigant Consulting believes that many retailers have full requirements contracts for NSLS customers and that any changes to LDCs' NSLS from demand response initiatives would be relatively insignificant in the short term. Also, the changes in the NSLS would likely favour the retailers' suppliers in that demand would be lower during high-priced periods.

***Key impediments to the use of residential interval meters***

LDCs' view high implementation costs and lack of customer incentive under the fixed retail price as the primary barriers to interval meters for residential customers. The following comments are representative of respondents' concerns:

> *High cost and little opportunity to shift load*
>
> *Fixed price of 4.3 cents/kWh removes the required financial incentive and pricing signal*
>
> *Fixed rate removes price signal and is below actual market price*
>
> *Price signals need to be very strong to outweigh distribution costs*

Issues and costs associated with implementing interval meters included the following:

- cost of meters and communication link
- higher reading and bill processing costs
- technical issues
- software issues
- retrofit wiring difficulty
- need to share customer phone line for data link, could lead to missed readings
- could impact accuracy of NSLS calculation (if missing meter data[a]).

One respondent felt that TOU meters might be preferable given their lower capital cost and the fact they can be read cheaply using the existing manual meter reading process.

***Role of LDCs in facilitating demand response***

Respondents were also asked about their desired or perceived role in facilitating demand response. Generally, respondent LDCs saw themselves as as facilitators providing services on a cost-recovery basis. They also expressed a limited appetite for investment (and only if the returns were guaranteed):

> *They have no money to do anything*
>
> *We can be active participants provided we are allowed to recapture costs*
>
> *LDCs can educate, promote and manage DSM programs*

[a] Given the relative homogeneity of residential customers, it may be possible to develop a work-around solution for missing meter data based on extrapolation from other similar customers' meter reads

The services LDCs reported that they could provide and the roles they could serve include the following:

- Educating customers
- Promoting programs
- Managing programs
- Acting as meter service provider and billing agent
- Liaison (supplier to customer, government to customer/supplier, etc.)
- Front-line delivery
- Ability to provide fixed price contracts
- Capacity support
- Distributed generation
- Traditional demand response programs and interval metering plus new load shedding programs
- Offering various incentives for customers allowing to have their A/C or hot water heaters controlled by LDC

***LDCs can offer targeted voltage reduction as a demand response resource, but this raises some critical questions***

It was also reported that some LDCs have on-load tap changers that could be used to provide more localized voltage reductions than those available to the IMO as part of its emergency response routine[a]. The IMO does include system wide voltage reduction in its emergency response procedures and this voltage reduction occurs prior to implementation of the Emergency Demand Response Program. Hence, the opportunity to utilize LDCs voltage reduction capabilities could be considered as part of the IMO's dispatchable load programs. However, this raises a critical question – should LDCs be allowed to undertake targeted voltage reduction before (and possibly more frequently than) the IMO's system-wide voltage reduction? To the extent that LDCs have local market knowledge as to which customers can tolerate specific levels of voltage reduction and the voltage reductions provided by LDCs are within specification, Navigant Consulting believes this could represent an interesting opportunity for both LDCs and the IMO.

[a] Many of these same devices would maintain voltage for certain LDC feeders and customers after the IMO implements a system-wide voltage reduction.

# CURRENT MARKET SITUATION

This section provides an overview of the current situation in the Ontario electricity market, impediments to demand response and suggested mechanisms to overcome these impediments.

***Focus of all market participants was on market readiness***

In the period leading up to market opening, the focus of all market participants was on addressing the myriad of regulatory, systems and process changes needed for market readiness. For the most part, these efforts were successful and the market opened on May 1, 2002 with significant levels of customers switching and with customers who had not entered into retail contracts being exposed to wholesale market price fluctuations. Given the necessary focus of market participants and agencies on market readiness, there was little time for lower priority activities such as determining how demand response could be incorporated into the Ontario electricity market design.

***Certain characteristics of the wholesale market impede demand response, IMO addressing many of these***

The Ontario wholesale electricity market is characterized by relatively tight supply (although price levels are somewhat dampened by the Intertie Offer Guarantee or IOG[a]), discrepancies between pre-dispatch and real-time prices and absence of a short-term (e.g., hour-ahead or day-ahead) forward market. These factors impede demand response in Ontario. Navigant Consulting is aware that the IMO is taking the initiative to reduce the level of discrepancy between pre-dispatch and real-time prices and is exploring mechanisms to facilitate wholesale demand response.

***Demand response is not always "visible" or known to the IMO before the fact***

Many customers that are IMO-market participants are relatively sophisticated with respect to demand response and provide some demand response during high price periods[b], but the magnitude of this demand response is not known to the IMO before the fact with any certainty and hence cannot be incorporated in the IMO's optimisation and dispatch algorithms. Large customers that are IMO-market participants likely represent the best opportunity for short-term demand response. Large customers served by LDCs that previously participated in utility peak load management programs represent a potential demand response resource in the future but these customers have the same concerns with discrepancies between pre-dispatch and real-time prices as customers that are wholesale market participants. Other customers that are not IMO-market participants are typically less sophisticated with respect to demand response but could be expected to

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[a] The Import Offer Guarantee is a "*make whole to the accepted offer price*" payment that can arise when the real-time price is lower than the price of intertie offers previously accepted and scheduled for that hour and serving as the basis for the pre-dispatch price.

[b] In its *Monitoring Report on the IMO-Administered Markets for the Period from September 2002 – January 2003*, released March 24, 2003, the IMO's Market Surveillance Panel found strong evidence of price responsiveness among 18 of the 90 large industrial customers in Ontario.

provide some demand response over the medium term under the right circumstances.

### *Bill 210*

***Half the market is no longer exposed to wholesale market prices***

The introduction of Bill 210 and subsequent regulation has resulted in fixed prices for low volume and designated customers representing an estimated 50% of market volume through 2006. The implications of this retail price freeze are discussed below. Mechanisms to encourage demand response among low volume and designated customers must allow customers to remain eligible for the 4.3 cents/kWh retail price outside those periods when they provide demand response.

***Role of the OEB***

Bill 210 effected a change in the Energy Board Act, 1998 stipulating that one of the roles of the OEB is:

> *To promote energy conservation, energy efficiency, load management and the use of cleaner energy sources, including alternative and renewable energy sources, in a manner consistent with the policies of the Government of Ontario.*

Bill 210 included a provision for the Minister of Energy to issue directives for the OEB to take steps to promote energy efficiency, load management and the use of cleaner energy sources, including alternative and renewable energy sources. This suggests that the Government could play a significant role as a catalyst in encouraging greater demand response in Ontario through policy changes and directives to market participants, such as the IMO, the OEB, LDCs and retailers.

Bill 210 also requires Ministerial approval of all transmission and distribution rate applications, which has had the effect of capping transmission and distribution rates (absent Ministerial approval). As a result of the distribution rate cap, LDCs may be less willing to undertake demand response than they might otherwise have been unless they are mandated to do so and/or the costs they incur for doing so are recoverable through rates.

***Business Protection Plan Rebate simpler than MPMA rebate***

On March 21, 2003, the Government announced its “Business Protection Plan” for large customers, stipulating that the annual consumption threshold for price freeze eligibility would be expanded to 250,000 kWh, and would be retroactive to market opening. For consumers subject to market, rather than fixed, pricing, the *Business Protection Plan* simplifies the calculation of the rebate payment. Starting in the second market year, the rebate will be fixed at 50% of the difference between the volume-weighted average HOEP and $38/MWh, and will be paid quarterly rather than annually. This new rebate mechanism is referred to as the Business Protection Plan Rebate (BPPR).

Many retailers have either shut down or significantly downsized their operations in response to Bill 210. Since the recent announcement by the Government that the retail price freeze will not be extended to medium and large business customers, Navigant Consulting expects that some retailers will continue to operate in the Ontario market and some level of retailer support in demand response may be anticipated. However, the level of retailer resources in the Ontario market is expected to be lower than in most other competitive markets for some time.

***Retailer activity has dropped significantly, but should pick up since large customers require risk management***

Retailers and marketers contacted by Navigant Consulting stated their preference for market-based solutions rather than further Government intervention. They felt "shell-shocked" by recent events and are focusing on their core business. Some would like to help deliver demand response solutions because they see value in such solutions and have the customer base. Retailers have indicated that they would like to participate through load controlled water heater programs and other programs.

### Government Review of the OEB's Mandate

On April 15 2003, the provincial government announced the appointment of a new Chair of the OEB and outlined the government's intention to introduce legislation to strengthen and enhance the OEB. This announcement was made while this Blueprint was being finalized and details of the proposed legislation were not available. As such, it is not possible to assess and report on the implications, if any, of this announcement and the proposed changes to the OEB mandate.

While most of the proposed changes would appear to enhance operational efficiency and management within the OEB, the government announcement was silent with respect to the independence of the OEB. Reduced independence for the OEB could discourage new market entrants from entering the wholesale market and hence could increase the need for demand response in the long term. This issue is perhaps even more important for the IMO – the Ministerial review of any market rule changes as stipulated in Bill 210 could be seen as affecting the independence of the IMO and could discourage new market entrants.

***Government actions affecting the independence of the OEB and the IMO could increase the future need for demand response***

### Wholesale Market Participant Perspectives

Navigant Consulting surveyed a small number of wholesale market participants to get a better sense of their issues and opportunities with respect to demand response. Most of the customers surveyed are relatively sophisticated and all have a dedicated energy manager. Most of these customers have some form of sophisticated energy management system to allow real-time tracking of HOEP or 5-min MCP, and some have automated load control algorithms. Most of the customers surveyed are not IMO dispatchable loads, but all reported being price-sensitive and reported having tried to shift load and respond to high prices.

***Reported barriers to becoming dispatchable***

The largest single barrier to the surveyed customers becoming dispatchable is the unreliability of the IMO's pre-dispatch price signal:

> *Need to make it financially worthwhile before making necessary infrastructure investments*

Some customers' processes must be down for several hours, and typical price spikes don't last that long (the opportunity cost of responding is not supported by prices, nor is there sufficient certainty regarding the duration of the dispatch event to warrant taking the necessary action to mitigate demand). Other barriers reported by customers included the following:

- Operating reserve (OR) payments are insufficient and (OR) prices vary widely
- Requirement of having 24-hour coverage and manpower required for computer terminal (although some dispatchable load customers report they do not feel it is necessary to provide 24 hour coverage)
- 20 second requirement for responding to dispatch instructions (although it may be possible to configure the workstation to provide this response automatically)
- Complexity of offering dispatchable energy and operating reserve simultaneously
- Onerous dispatchable load registration process

With respect to their ability to respond to an accurate pre-dispatch signal, all customers would prefer one-day notice, but many are able to respond within one hour, and some in as few as five minutes. This finding highlights the significant variation in response time among large, sophisticated customers and supports the efforts of other ISOs to provide a range of programs, with differing notification periods, to wholesale market participants.

Customer suggestions to encourage greater demand response included the following:

***Wholesale market participant suggestions to encourage demand response***

- Improve the accuracy of pre-dispatch price signals
- Make dispatchable load and demand response worthwhile and accessible
- Consider peak period only dispatchable program: this would eliminate the need for 24/7 coverage of the dispatch workstation
- Eliminate 20-second response requirement

- Market the additional benefit of bidding into the operating reserve market to improve economics – this bidding may not be as onerous as many customers imagine.

- Contracting strategies don't preclude demand response

***Marginal consumption always at the spot price under "block" contracts***

In order to mitigate against price risk, many customers have entered into fixed price electricity contracts for some portion of their annual consumption. For most large customers, these are typically "block" contracts for a certain amount of power (say 10 MW) for the peak hours or on a 24/7 baseload basis. Under the terms of most block contracts, the customer commits to purchasing the block volume for the contract term. Any consumption greater than the block amount is automatically purchased by the customer at spot prices under the terms of the contract, and if the customer's consumption is less than the block amount, the difference is automatically "sold" by the customer at spot prices. Hence, marginal consumption for customers under block contracts is always at spot prices and they would still be able to participate in demand response programs. Customers with full requirements contracts (which provide the same fixed price regardless of consumption level)[a] are not exposed to spot prices and would be unlikely to participate in demand response programs.

# Metering and Rate Tariff Practices

***Retail price freeze and Net System Load Shape are the most significant metering and rate practices impeding demand response***

The most significant metering and rate tariff practices impeding demand response in Ontario's electricity market are the retail price freeze, Net System Load Shape, averaged Wholesale Market Services Charge and absence of time-differentiated distribution charges. These issues are described in more detail in the following sections, along with a discussion of their potential impact, possible resolutions and suggestions for further analysis.

## Retail Price Freeze

Through Bill 210 and related regulations, the provincial Government has frozen the retail price of electricity for low volume and designated customers at 4.3 cents/kWh. Navigant Consulting estimates that these customers represent approximately 50% of market volume[b].

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a Navigant Consulting is aware that many residential and small business retail contracts based on NSLS load profiles were "full requirements" contracts.

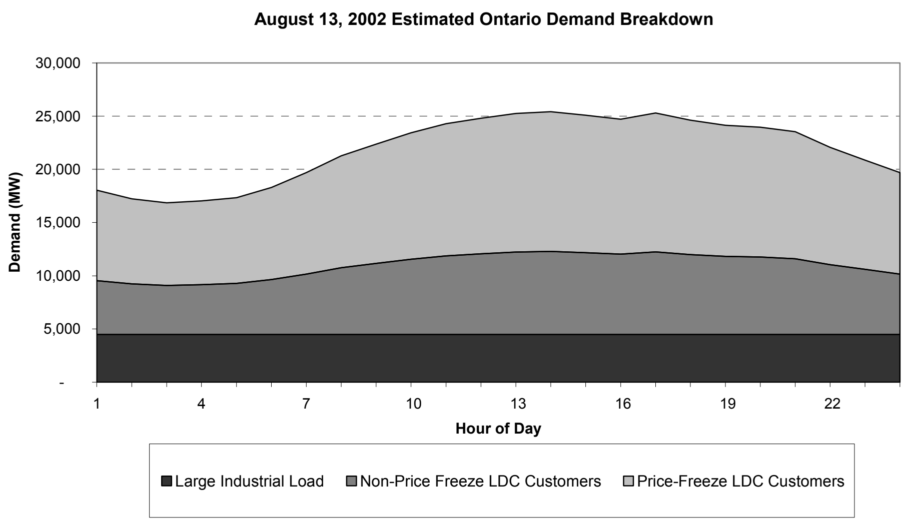
b Before the threshold for low volume customers was increased from 150,000 to 250,000 kWh annually, the IMO had estimated that low volume and designated customers represented 47% of market volume.

### *Issue*

The retail price freeze will impede demand response in Ontario, particularly among a customer group that has a significant contribution to peak demands.

While this group represents approximately 50% of overall electricity consumption in Ontario based on estimates provided by the IMO, Navigant Consulting estimates that they represent over 50% of consumption during high demand periods (such as during hot summer days or cold winter nights)[a]. As shown, the demand of low volume and designated customers was conservatively estimated to be more than 13,500 MW during the record peak demand of 25,414 experienced on August 13, 2002.

***Figure 7 – Estimated Ontario Load Breakdown – August 13, 2002***




The estimated load shape for the low volume and designated customers subject to the price freeze as calculated using the methodology described above is almost identical to the Net System Load Shape for Toronto Hydro Electric System Limited (THESL), as shown below in Figure 8. This comparison suggests that the estimation methodology is reasonably accurate.

[a] Assuming wholesale market participants represent 20% of total market volume and have a 100% load factor, and that the load profile for low volume and designated customers who are subject to the retail price freeze is the same as other LDC customers.

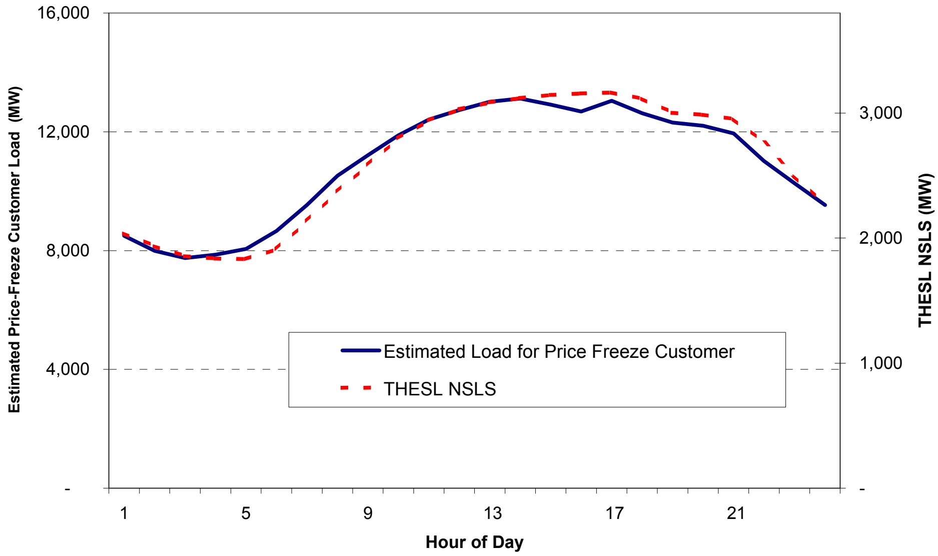



***Figure 8 – Comparison of Estimated Price-Freeze Customer Load vs. THESL NSLS - August 13, 2002***

The contribution of low volume and designated customers subject to the price freeze is similar during cold winter days. The low volume and designated customers are estimated to represent a peak demand of almost 13,000 MW during Ontario's winter peak of just over 24,000 MW on January 22, 2003.

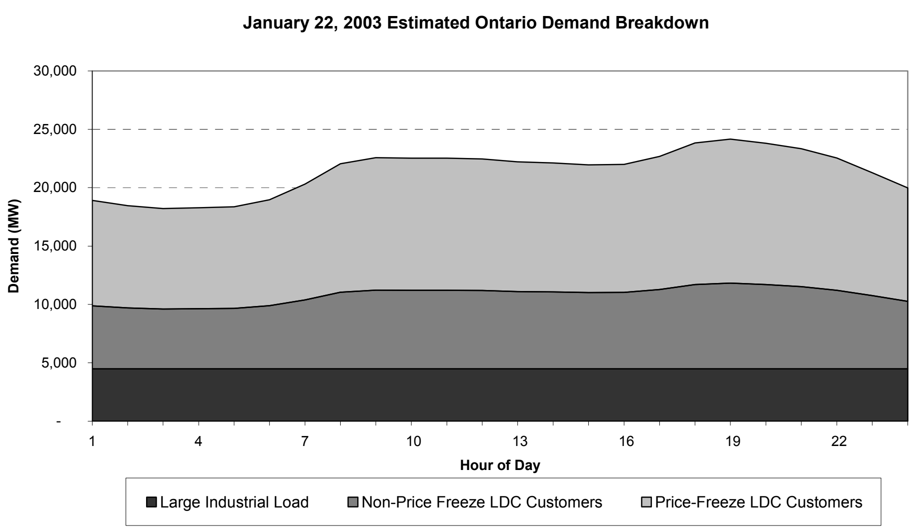



***Figure 9 – Estimated Ontario Load Breakdown – January 22, 2003***

The assumed load profile used for settlement purposes for most of this customer group is based on the local LDC's Net System Load Shape (NSLS), which is discussed in detail in the following section. However, some customers within this group have interval meters (eg, large sites of designated customers, such as municipal water treatment plants, hospitals and universities).

Under the price freeze, the Government is responsible for buying down the cost of power from the wholesale market price down to the fixed retail price (net of the MPMA rebate). As such, any reductions in the wholesale cost of power for this customer group through demand response would accrue directly to the Government.

***Government has to cover difference between wholesale price and $43/MWh***

### *Potential Impact*

Given that the price freeze virtually eliminates any potential demand response from more than 50% of the demand during high demand periods (when demand response is most valuable), the price freeze is a significant impediment to demand response in Ontario.

***Price freeze is a significant impediment to demand response***

This problem could be exacerbated by price elasticity effects, as customers respond to prices that are lower than they would otherwise have been. For example, if low volume and designated customers' marginal electricity costs under the price freeze are 20% lower than they otherwise would be, the freeze could actually increase electricity use by as much as 2% (assuming an elasticity of –0.1), exacerbating the potential need for demand response. Hence, instead of a peak demand during a hot summer day of say 13,600 MW, the peak demand for this group could increase by 270 MW to 13,870 MW, which would 1) make prices more volatile and 2) increase the overall cost of the retail price freeze for the Government.

***Elasticity effect could exacerbate impact of price freeze***

### *Possible Resolutions*

Any resolution or mechanism to encourage demand response among this customer group must remain consistent with Government policy objectives with respect to the 4.3 cent retail price freeze. Hence, customers who provide (or attempt to provide) demand response should not be exposed to prices any higher than they would otherwise face. This suggests that the 4.3 cents/kWh should serve as a ceiling for low volume and designated customers while the price freeze is in effect.

The possible resolutions will vary depending on whether the customer's load is measured with an interval meter or the LDC's NSLS.

Options for NSLS customers include any of the following individually or in combination:

***Options for NSLS customers***

- Requiring interval meters for new homes with appropriate pricing signals/tariffs to elicit demand response (this is discussed in detail in the *Interval Meters* section on page 20).
- Allowing NSLS customers to provide demand response through water heater load control and other direct load control mechanisms and providing an incentive based on the "value" of the response provided.

- Providing TOU rates to customers with existing TOU meters that yield 4.3 cents / kWh on average, but allows lower rates if customers shift consumption.

- As an option for low volume customers, providing CPP rates with "smart" thermostats / controls that yield 4.3 cents / kWh on average for customers that don't change their consumption patterns (ie, don't provide demand response), but allows lower rates if customers shift consumption out of the higher priced periods. Participants in this and other similar programs would help to firm up estimates of the cost-effectiveness of interval meters.

Options for interval metered customers include allowing them to participate in the wholesale market or having LDCs bid them in as a "dispatchable" load, just like a wholesale market participant (Note that either of these options would allow the IMO would "see" this demand response).

***Key policy issues to facilitate demand response among customers eligible for the retail price freeze***

All of these may be viable options, but they raise several critical issues:.

- Should Ontario consider implementing measures that may provide some demand response in the short term, but that are not compatible with the long-term market structure and rules? For example, TOU rates are likely not compatible with the long-term market structure and rules, but could provide some short-term demand response (particularly if the TOU meters are already in place). In answering this question, it is important to determine whether the expected benefits of any such initiatives justify the investment costs necessary to implement and operate these initiatives over the short term. Similarly, the use of load sampling or other techniques not involving interval meters may not be compatible with the long-term market structure, but may be appropriate for short-term programs such as direct control of water heaters by LDCs.

***How should the capital and operating costs of the infrastructure be recovered***

- How should the capital and operating costs of the infrastructure necessary to allow these options be allocated between participants, non-participants and the entities incurring these capital and operating costs? Since non-participants will still pay 4.3 cents/kWh under the price freeze, should they be expected to contribute at all? How can any incremental LDC costs be recovered under a distribution rate cap?

- As the primary beneficiary of demand response among low volume and designated customers, should the Government provide a financial contribution to participating customers and / or LDCs?

- Policies with regard to incentives and cost recovery for demand response measures among low volume and designated customers should, to the maximum extent possible, be consistent with government policy regarding funding for broader DSM measures, such as encouragement of energy efficiency and conservation. It is also important to recognize the potential interactive effects of demand response and energy efficiency programs. As a simple example, encouraging the installation of high efficiency air conditioners will reduce the peak demand of customers installing such air-conditioners and will lessen the impact of any demand response from these customers compared with customers using "standard" air-conditioners.

***Need for consistency with broader DSM measures, need to recognize interactive effects***

- How important is it for the IMO to "see" any demand response that might be effected through these mechanisms before the fact (for better forecast accuracy) instead of after the fact? Could LDCs and demand response aggregators bid these resources into an IMO demand response program, in the same way that some ISOs in the US allow Load Serving Entities and Demand Response Aggregators to bid on behalf of participating customers?

- When demand response from this customer group could be realized is an issue. Assuming further analysis and/or pilots undertaken in 2003, the earliest possible date for broader implementation is probably 2004. This would provide two or three years at most under the retail rate freeze, at which point customers would be fully exposed to wholesale market prices. An associated question is when would demand response be most valuable in the Ontario market?

***Timing is an important issue – could start pilots in 2003 and expand in 2004***

- Should the value of demand response within a given LDC be based on the difference between the customer's load and the LDC's NSLS or the overall system load shape? In effect, the Government has entered into full requirements contracts with low volume and designated customers of all LDCs. The costs of these "contracts" vary according to the LDC's NSLS. For this reason, Navigant Consulting believes that the value of demand response should be based on each LDC's NSLS. This approach reflects the Government's implied contract with customers through each LDC. If this approach is deemed too complicated, an approach based on the overall system load shape could be considered, but it is important to recognize the potential for cross-subsidies between and across LDCs according to their unique NSLS.

***Government cost varies with LDC's NSLS***

### *Further Analysis*

As a first step, Navigant Consulting believes that the Government, the OEB and the IMO need to consider the issues identified above and establish appropriate policies to guide decision-making.

***Government, OEB and IMO need to consider issues and establish policies***

With respect to the cost-effectiveness of capturing demand response from customers subject to the 4.3 cents/kWh retail price freeze, Navigant Consulting is confident that several of the possible mechanisms discussed would ultimately prove cost-effective with further analysis and study. This analysis is beyond the scope of this project.

***Expected benefits from demand response would justify financial support from the Government***

Navigant Consulting also expects that the beneficial impact that demand response from low volume and designated customers would have on the cost of the Government "buy-down" from wholesale market prices to 4.3 cents/kWh would allow some form of financial support from the Government to participating customers and LDCs and other entities that invest and operate the demand response programs.

## Net System Load Shape

***Net System Load Shape (NSLS) key feature of retail settlement process***

One of the key features of the Ontario electricity market's retail settlement rules is that, with the exception of street lighting, all customers without interval meters in a given LDC are assumed to have the same load profile. This load profile, called the Net System Load Shape (NSLS), is determined by subtracting the load of all interval metered customers served by an LDC from the LDC's total wholesale market purchases. When an NSLS customer's meter is read, the energy consumed by the customer is allocated according to the LDC's NSLS during the meter reading interval.

### *Issue*

***NSLS is an impediment to demand response***

This approach greatly simplifies retail settlement but can serve as an impediment to demand response. For example, if a customer shuts off their air conditioner during a hot summer day, the LDC's NSLS would change only slightly. The customer who shut off their air conditioner would benefit marginally from a slightly different NSLS and marginally lower energy consumption (since they didn't operate their air conditioner for one day), but most of the benefits created by the customer's action would flow to other customers through the modified NSLS.

### *Potential Impact*

***Retail price freeze exacerbates the problem***

Prior to the introduction of the retail price freeze, NSLS impeded demand response since NSLS customers were not able to take any actions to avoid high energy prices. The retail price freeze exacerbates this problem, suggesting that without changes to recognize and reward demand response among this customer group, there will be no meaningful demand response from NSLS customers under the retail price freeze.

### Possible Resolution

Two possible resolutions to allow demand response activities of this customer group to be recognized are:

***Possible resolutions include installing interval meters and developing segment-specific load profiles***

- Installation of interval meters, and
- Development of dynamic, segment-specific load profiles.

The potential costs and benefits of interval meters are discussed in detail in *Interval Meters* on page 20.

The development and use of segment-specific load profiles has proven effective in various other jurisdictions and could be applied in Ontario. Generally, the profiles are developed based on a small sample of customers who are representative of the segment of interest. In Ontario, the most viable application of segment-specific load profiles would be for those customers whose loads are directly controlled by another entity, such as an LDC, retailer or demand response aggregator/provider. This would address the concern that load profiling doesn't reflect the user-pay principle (essentially, load profiling would establish a segment-specific "NSLS", but the actions of individual customers within the segment would not be recognized unless they were included in the meter sample).

***Segment-specific load profiles could be used for loads that are directly controlled***

A simple example is provided to demonstrate the potential advantages of load sampling for direct control of customer water heaters. Assume that an LDC has 10,000 customers with water heaters that it could remotely control and the LDC wishes to estimate the impact that the direct load control has on the load profile of the target customers. The LDC would install interval meters at a representative sample of perhaps 50 target customers. Assuming $400 / interval meter, the capital costs for the equipment necessary for the sampling would be $20,000. The load shape for these sampled customers would then serve as the assumed load shape for all target customers whose water heaters were directly controlled by the LDC. This assumes a uniform load control strategy for all direct load control customers within the LDC. If the LDC decided to implement two different load control strategies for different segments, it would require two distinct customer samples.

***Load sampling could be based on 50 interval meters installed at a representative sample from a population of 10,000 customers***

### Further Analysis

The OEB should investigate 1) the costs and benefits of establishing one or more dynamic segment-specific load profiles within specific LDCs that have a potential demand response application, and 2) the implications to LDCs, retailers, OEFC and customers of using these load profiles for settlement purposes. The other question related to how customers subject to the retail price freeze could be compensated for providing demand response was dealt with in the previous section.

## Averaged Wholesale Market Services Charges

***LDCs recover IMO fees and uplift through a fixed charge***

As required by the OEB, most, if not all, LDCs recover the IMO fees and uplift charges they pay to the IMO through a fixed Wholesale Market Services Charge (WMSC) of approximately $5.20 / MWh. This charge is levied on all interval-metered and NSLS customers based on their energy consumption. Over or under-recovery of these charges relative to costs are collected in a variance account for future recovery, subject to OEB and/or Ministerial approval.

***But the LDC's IMO costs vary and are most volatile during periods of high demand***

Although the WMSC is fixed, the uplift charges paid by LDCs, which include the cost of Intertie Offer Guarantees, vary from hour to hour. Although uplift charges since market opening have averaged in the $4 / MWh range, uplift charges can be significant during periods when demand is highest.

### *Issue*

The recovery of time-varying uplift costs through a fixed charge impedes demand response, particularly during those periods when demand response would be most valuable. As shown in Table 4, uplift charges averaged $23 / MWh during the 6% of time when HOEP was greater than $100 / MWh between May 1, 2002 and February 18, 2003. The average uplift was $37 / MWh during the 3% of time when HOEP was greater than $150 / MWh and $60 / MWh when HOEP was greater than $200 / MWh.

***Table 4 – Uplift During Periods of High HOEP (May 1, 2002 through February 18, 2003)***

| HOEP Greater than… | Hours | % of Total Hours | Average HOEP ($/MWh) | Average Uplift ($/MWh) | % of HOEP |
|---|---|---|---|---|---|
| $100/MWh | 451 | 6% | $162 | $23 | 14% |
| $150/MWh | 238 | 3% | $246 | $37 | 15% |
| $200/MWh | 97 | 1% | $367 | $60 | 16% |

Hourly uplift charges and HOEP are shown for August 13, 2002 in Figure 10. During the fifteen hours during this day when HOEP was greater than $100 / MWh, the average uplift charges were $44 / MWh, just over 16% of the average HOEP of $267 / MWh.

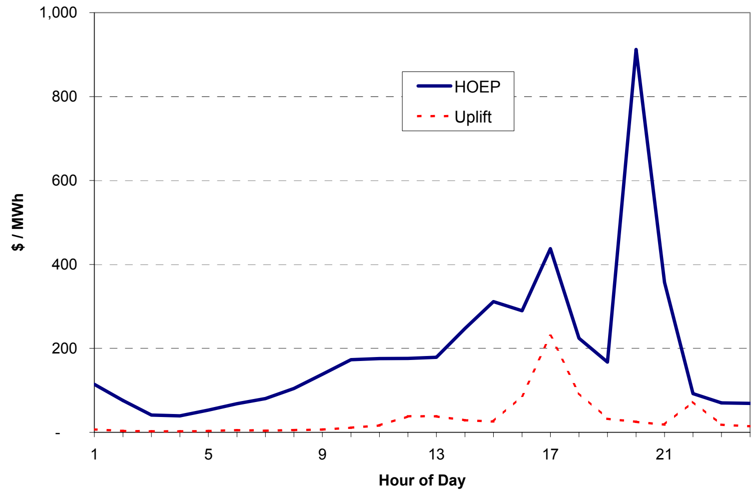



***Figure 10 – Uplift and HOEP on August 13, 2002***

### *Potential Impact*

***Potential demand response 14% lower with fixed WMSC than time-varying WMSC***

All other things being equal, Navigant Consulting estimates that the potential demand response from non-designated LDC customers with interval meters is at least 14% lower through a fixed WMSC than if LDCs flowed through uplift charges to these customers on an hourly basis. This impact estimate conservatively assumes that demand response among this customer group would be driven by a price elasticity that is constant regardless of price – since the prices customers would be exposed to are 14% lower than they would be if they were fully exposed to HOEP plus uplift, the expected demand response would be 14% lower. For example, if the expected demand response from this group of customers was 200 MW with a fixed WMSC, the demand response could increase to 230 MW with time-varying uplift charges.

Another potential impact of a fixed WMSC is that it may decrease the number of hours during which customers are "demand-responsive". As shown in Table 4, HOEP was greater than $100 / MWh[a] for approximately 6% of the time between May 1, 2002 and February 18, 2003. However, the combined HOEP plus uplift charges were greater than $100 / MWh for almost 9% of the time, roughly fifty percent more hours than when just HOEP was greater than $100 / MWh.

### *Possible Resolution*

LDCs could charge uplift to customers with interval meters on an hourly basis, in the same manner as they currently charge HOEP.

[a] The $100 / MWh represents a reasonable minimum threshold for some form of demand response by some customers.

### *Further Analysis*

The costs for the necessary LDC system changes should be investigated and compared to the expected benefits in terms of incremental demand response and impact on overall market prices. Given that the LDCs 1) already have the customer interval metering data and 2) are currently charging these customers HOEP on an hourly basis, the magnitude of the necessary system changes may not be significant.

***Investigate costs of LDC system changes to facilitate hourly WMSC for interval metered customers***

One potential issue with hourly uplift charges may be associated with the time lag before final uplift costs are available from the IMO. This time lag is longer than that for final HOEP costs so there may be a need for some sort of interim variance account to allow LDCs to bill customers according to estimated uplift (and final HOEP), with recovery of any variance due once uplift charges are finalized.

## Non-Time Differentiated Distribution Charges

Most, if not all, LDCs in Ontario have distribution charges that do not differentiate when customers consume energy or when they set their peak demand. For example, a customer that sets a peak demand of 1000 kW at 2 pm on a hot summer day will pay the same distribution demand charges as another customer that sets a peak demand of 1000 kW at 3 am.

### *Issue*

The lack of time-differentiated distribution charges impedes large scale load shifting among certain customers. Sample customers could include foundries and other customers with large, shiftable loads.

***Lack of time-differentiated distribution charges impedes load shifting***

### *Possible Resolution*

Introduce time-differentiated demand charges for large interval metered customers. This same approach could be extended to small customers (through time-differentiated energy rates) if and when interval meters are introduced to smaller customers. For example, these smaller customers could have a time-differentiated demand component in their distribution charges as described above for large interval metered customers or simply time-varying energy charges such as 1 cent/kWh during the peak period, but 0.5 cents/kWh during off-peak periods..

### *Further Analysis*

Introduction of time-differentiated distribution charges would require 1) changes to LDC billing systems and 2) information regarding cost attribution within LDCs to develop fair and equitable rates. The OEB could review the expected costs and benefits for a small sample of utilities before making a determination whether LDCs should introduce such rates in the future. Collection of the necessary system load and cost data should also be considered in future cost allocation studies to inform any changes in rate structure.

***Transmission charges are partially time-differentiated, but may still be an impediment to demand response***

Transmission charges are partially time-differentiated with network charges based on the maximum of a customer's coincident peak demand or 85% of the customer's non-coincident peak demand between 7 am and 7 pm on non-holiday weekdays. This rate structure could be seen as an impediment to demand response in that a customer who provides some demand response (and reduces their coincident peak) would still incur significant network charges. To explore and address this issue, the OEB could review the transmission rate structure as part of a broader study into demand response and DSM.

# VALUING DEMAND RESPONSE

***Value of demand response have been hotly debated***

This section discusses the issues associated with valuing demand response. These issues have been hotly debated in the recent past.[a] The debate has revolved primarily around whether customers should be paid not to consume.

## Determining the Value of Demand Response

***Demand response can result in lower prices for all customers in certain situations***

Numerous analyses and studies have indicated that demand response during periods of high prices can result in lower overall electricity prices for all customers, not just those providing the demand response. Note that these analyses focus on periods when market prices are high and demand crosses the supply curve at a point where the supply curve is relatively steep. On these occasions, market prices change dramatically with relatively small increases in demand.

***250 MW of incremental demand response in Ontario would have reduced wholesale electricity costs by $170 M since market opening***

Based on confidential information provided by the IMO, Navigant Consulting estimates that if the Ontario market had 250 MW of additional demand response (~ 1% of peak Ontario demand) during those periods when HOEP was greater than $120 / MWh, average prices in Ontario since market opening would have been almost 2% lower, representing approximately $170 million in reduced electricity costs for all customers. This reflects the fact that the Ontario supply curve is quite steep whenever HOEP is greater than $100 / MWh and small reductions in demand can have a significant impact on market prices.

Similar analysis for the California market indicated that a 2.5% reduction in demand during peak demand periods in California during the summer of 2000 would have reduced wholesale prices during these peak periods by 20% and would have reduced the cost of power for the summer by 6%[b]. The California results are essentially the same as for Ontario, assuming a similar percentage reduction in demand. Using the same methodology as described above for Ontario, a 2.5% reduction in peak demand (representing 625 MW of additional demand response) for Ontario would have reduced wholesale prices by approximately 5% since market opening.

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[a] Comments provided by stakeholders in response to a draft version of this report reflected the divergent views of different groups regarding the appropriateness of paying customers not to consume. In general, loads were supportive of paying customers not to consume; whereas generators were opposed to this policy.

[b] *The Politics of Power Grids*, Asian Times On-line, Ahmad Faraqui, August 8, 2002

### *Flow of Costs and Benefits from Demand Response*

If there had been 250 MW of incremental demand response in the Ontario market, the resulting flow of costs and benefits would have been as follows[a]:

***Flow of costs and benefits from market-price based demand response***

- Customers providing the 250 MW of demand response would have saved approximately $20 million by reducing their demand when HOEP was greater than $120 / MWh
- Other customers would have saved approximately $170 million due to lower HOEP and would have enjoyed greater reliability given the increase in reserve margins as a result of the demand response, and
- Generators would have received approximately $190 million less revenues due to lower HOEP and lower energy sales.

This analysis highlights one of the key impacts of demand response – the demand response of a small number of customers can result in significant transfers from generators to other customers. Assuming the customers providing the demand response did so based strictly on price signals (ie, their opportunity costs were less than the cost of electricity), this would be considered an efficient market outcome. Customers who valued the energy less than its cost to them reduced their consumption such that all energy consumed was valued more than or equal to the purchase price. This results in allocative efficiency (ie, the allocation of resources to those uses with the greatest value to society). In the electricity industry, allocative efficiency requires that electricity be priced at a level that reflects its true costs to the society. This requires getting the prices "right" so that consumers can make appropriate consumption decisions and appropriate investment decisions can be made by producers and consumers.

The situation would become more complicated if there was another group of customers who were not willing to reduce consumption based solely on market price signals, but who would provide demand response of perhaps 100 MW if they were paid for the energy they did not use (this is analogous to an "economic" demand response program where customers are paid not to consume). In addition to avoiding these high prices, these customers would receive a supplemental payment to reduce their consumption during this critical period. In this situation, Ontario would have had an incremental 350 MW of demand response and other customers would have saved $235 million (ie, $65 million more than the previous example) provided they were willing to pay the group of customers representing 100 MW of "economic" demand response not to consume. Assuming the payment "not to consume" was based on market prices, the

[a] For simplicity, this example and the following examples do not include the impact of the Business Price Protection Rebate and the Market Power Mitigation Agreement.

payment would have been approximately $7 million. Generators in turn would have their revenues reduced by $235 million, causing this transaction to be a net transfer from generators to consumers.

***Are customers willing to pay other customers to use less if it reduces their overall electricity costs?***

So, the question for the other customers becomes essentially:

> *Are you willing to pay $7 million to a group of customers who are willing to reduce their demand if this reduced your overall costs by $65 million?*

Recognizing that the shape of the industry supply curve is consistently very steep at high prices such that a relatively small reduction in demand can yield a significant reduction in price, the consumer group would likely agree to compensate other customers who have the ability to reduce load to do so to produce a reduction in prices.

In situations where there is a supplemental payment to consumers, there is an equity concern. Consumers benefit and suppliers are disadvantaged. This raises questions as to whether the IMO should undertake an activity that pits two classes of market participants against each other. However, given that there are clear consumer benefits it would be an activity that consumers may desire to undertake.

***Benefits of economic demand response may be transitory***

To the degree that higher prices are needed to incent the development of additional generating capacity, then the benefits of any economic demand response program can be viewed as transitory since these higher prices will have to be realized eventually to enable generators to realize an adequate return on their investment. While these savings will not be realized indefinitely, they are likely to be significant and meaningful reductions in costs for consumers.

Provided that only those customers who would not otherwise provide demand response were paid, the "transaction" described above makes sense from a customer perspective – the overall cost to customers would be lower than it otherwise would have been. But, what if the original group of customers representing 250 MW of demand response also wanted to be paid "not to consume" even if they were willing to do so anyway.

The question for the other customers then becomes:

> *Would you be willing to pay $24 million to a group of customers (some of whom would have done it anyway) that are willing to reduce their demand if this reduced your overall costs by $235 million?*

Again, the answer would likely be yes, but the other customers would probably prefer not to pay the original group of customers that would have reduced their demand anyway. In this situation, all 350 MW of demand response would be paid not to consume and the flow of costs and benefits would be as follows:

***Flow of costs and benefits with an economic demand response program in which customers are paid not to consume***

- The original group of customers who would have provided 250 MW of demand response anyway would reduce their electricity costs by $20 million and would also be paid approximately $17M (assuming the payment was based on the lower HOEP) by other customers "not to consume". These customers would be considered "free-riders" in that they would have acted regardless of the incentive provided by other customers.

- The second group of customers who would only provide 100 MW of demand if they were "paid" to do so would reduce their electricity costs by $8 million and would be also be paid approximately $7M by other customers.

- Other customers would have saved approximately $235 million due to lower HOEP, but would have paid $25 million to realize these savings, and

- Generators would have received approximately $263 million less revenues due to lower HOEP and lower energy sales.

Again, from a customer perspective, this transaction makes sense. The group of customers providing the demand response can be seen to be receiving the value to the system of their agreement to reduce consumption. Note that in an electricity pool market, most generators (all those except the one on the margin) get a price above the amount they would have accepted. That is the point of having a single market price. Similarly, in the case of refraining from consumption, all of the consumers providing such services get the same (market) price, regardless of their reservation price.

It should be noted also that the reduction in electricity cost from reduced consumption is not a dollar for dollar increase in profit for the consumer. The consumer had a productive use for the electricity. By reducing demand, the customer is foregoing that productive use and the profit it would have made from that use.

***Benefits can be more compelling if demand response is used for reliability purposes***

The above example is based on situations where there is still sufficient (albeit relatively expensive) supply to meet market demand. The benefits can be more compelling in those rare situations when there is not sufficient supply to meet demand. In these situations load shedding is the typical response after the system operator has exhausted all other mechanisms. In this event, customers who would have been willing to purchase electricity will not be able to do so. There are numerous estimates of the value of lost load, but most fall in the range of $5,000 to $10,000 / MWh. In these circumstances, demand response that prevents or forestalls rolling load shedding could be seen as providing economic value up to the value of lost load.

Others have argued that peaking units can serve the same function and offer the same reliability value. This is true. However, the owners of such peaking units will undoubtedly need to be compensated to provide such service, perhaps through some fixed payment scheme, whereas customers participating in an economic demand response program are likely willing to accept compensation only when called upon to reduce their consumption. Therefore economic demand response may produce a lower overall cost than a supply response.

***Economic demand response may produce a lower overall cost than a supply response in certain situations***

Another oft-cited benefit of demand response programs is as a market power mitigation technique. Demand response can be an effective deterrent to the exercise of market power. Programs that promote additional demand response have additional value for this reason.

This simple example highlights some of the issues associated with valuing demand response:

***Key issues with valuing demand response***

- Customers as a group are not well placed to make the sort of economic tradeoffs and demand/supply optimizations described in the previous hypothetical examples (they do not have information on the price impact that demand response can have and so, do not know whether they would be willing to pay other customers not to consume).
- Most competitive electricity markets are structured to minimize supply costs given a market demand; competitive electricity markets are not structured to optimally balance supply and demand.
- What is this optimal balance of supply and demand, particularly when demand and prices are high? Is society better off if load is reduced?
- While there are likely circumstances and situations where it would be economic for consumers to pay certain customers not to consume (ie, to offer an "economic" demand response program), there are likely to be free riders in these programs. However, paying all customers providing the demand response the same incentive would be consistent with the concept of paying all generators the market clearing price in an electricity pool market.
- How much is demand response worth if it can forestall load shedding?

These valuation issues exacerbate the other institutional and structural barriers to demand response. In an ideal world, demand response would compete on a level playing field with generation, but there are numerous factors that prevent the establishment of such a level playing field (the relevant factors for Ontario are discussed elsewhere in this report). As noted previously, as customers gain experience in providing demand response, they are likely to be more willing to continue to provide the demand response even under less attractive pricing

***Several barriers prevent demand response from operating on a level playing field with supply-side resources***

signals (ie, these customers may overestimate their opportunity costs initially, but are able to more accurately determine these costs with experience).

***There is merit in offering economic demand response program to 'kick start" the market***

This analysis suggests that there is merit in offering an "economic" demand response program (ie, paying customers not to consume) in order to "kick-start" the demand response market, provided that the estimated incremental impact of offering an economic demand response program is within economically acceptable limits. However, given that these programs result in a wealth transfer from generators to loads Navigant Consulting believes that this may not be an appropriate role for the IMO who must be able to balance the interests of all classes of market participants. However, given that the Ontario Government has taken on responsibility for market prices greater than $43/MWh for approximately half of the Ontario market it would be appropriate for the Government to sponsor economic demand response programs. Other mechanisms to capture market-price based economic demand response should also be pursued (ie, use of aggregators, longer lead times and allowance for non-interval metered loads) but it is important to recognize that the additional incentive provided by "economic" demand response programs will help customers and aggregators recover the costs of the necessary enabling technologies. Once these costs are recovered, these customers and aggregators may be able to provide demand response based solely on market price signals.

***Other ISOs are providing economic demand response programs***

This approach is generally consistent with the actions of other system operators that are 1) pursuing multiple channels to capture demand response resources as discussed in *ISO Programs* on page 3, and 2) providing one or more economic demand response programs in spite of their stated preference for "market-based" demand response.

***Should treat demand response as a demand-side resource, not a supply-side resource***

Another critical question related to the value of demand response is whether it should be treated as a supply-side or demand-side resource. Navigant Consulting believes demand response should be treated as a demand-side resource to the extent possible. This perspective helps system operators to recognize the unique characteristics of demand response vis-à-vis supply resources. Navigant Consulting also believes that demand response should be integrated into the supply dispatch algorithm to the extent possible. System operators generally prefer to see demand response before it happens so it is easier to incorporate into the dispatch algorithm. This visibility also allows the relative value of demand response to be determined. For Ontario, the IMO will only be able to "see" the demand response from wholesale market participants participating in one of the IMO's demand response programs, but over time, the IMO will develop better predictive accuracy and will be better able to reflect the demand response from other wholesale market participants and embedded LDC customers into its dispatch algorithm.

# RECOMMENDATIONS

***Vision for demand response, followed by timing considerations and recommendations***

As context for the recommendations, the introduction to this section provides a vision for demand response in Ontario, followed by timing and staging considerations that reflect the current market situation and support the vision. Areas and opportunities for co-operation among the Government, the IMO, the OEB and market participants are provided. Following this discussion, Navigant Consulting provides recommendations on actions that the IMO can take to facilitate demand response in Ontario, as well as suggested actions for the Government and the OEB, plus suggestions regarding worthwhile customer education activities. Finally, Navigant Consulting's perspective on topical demand response opportunities – interval meters for residential customers, interval meters for customers with peak demand > 200 kW and direct load control opportunities – is provided along with supporting rationale.

## Vision for Demand Response in Ontario

***Vision of demand response for 2010***

Assuming that the retail price freeze expires in 2006, Navigant Consulting proposes the following "vision" for demand response in Ontario, subject to rigorous cost effectiveness testing:

By 2010:

***Interval meters, wholesale price exposure and access to enabling technologies for all customers***

- All Ontario customers will have interval meters and will be fully exposed to wholesale market pricing.
- All customers will have access to the necessary enabling technologies, products and services to allow free customer choice in response to price signals (customers who do not wish to respond to wholesale market price signals can simply choose fixed price "full-requirements" contracts with retailers).

***Significant role for aggregators***

- Independent demand response aggregators will play a critical role in providing access to enabling technology and simplifying demand response for customers who are not wholesale market participants.
- The IMO will be able to accurately predict the impact of demand response at various price levels, times of year and times of day (but does not need to have advance notification of all demand response).

***Mostly price-responsive***

- Demand response will be primarily based on market prices, although there may be occasions (eg, for reliability and or when the supply curve becomes very steep) when it would be cost-effective for most customers to pay a small group of customers to reduce their demand. The decision-making associated with the transfers between customers on these occasions will be effected by the IMO or another agency objectively and impartially with the objective of minimizing the cost of meeting customers' stated or implied demand requirements.

- Demand response will provide a 10% reduction in overall demand during high priced periods (this would represent 3000 MW assuming a 30,000 MW market peak).

***10% reduction during peak demand periods***

- The structure and mechanisms for demand response in Ontario will be generally consistent those in neighbouring markets (ie, with minimal "seams" issues) allowing demand response providers to achieve economies of scale and scope in their services by serving broader regional and continental markets.

An illustration of the current situation versus the projected situation based on this vision is shown in Figure 11 for each of the four primary market segments and for the three cost components that can drive demand response. In this figure, red "cells" have the potential for full demand response, shaded cells have some limited potential (constrained for one or more reasons as noted below) and white cells have essentially no potential for demand response. An interim, transitional state achievable by 2005 based on the recommendations provided below is also shown in Figure 11. The following presents Navigant Consulting's rationale for the shading of the cells:

***Four primary market segments with three cost components that can drive demand response***

- Cells C1 and B1 are only partially shaded in 2003 based on concerns regarding the demand response impediment provided by discrepancies between the pre-dispatch and real-time prices.
- Cell B2 would become shaded if Wholesale Market Services Charges flow through dynamically instead of on a fixed price basis.
- Row A would become partially shaded for all customers with time-differentiated distribution charges.
- Cells B3 and C3 would become partially shaded with the extension of the mandatory interval metering threshold down to 200 kW
- Cells B4 and C4 will become shaded when the price freeze is lifted and/or customers have opportunities to provide demand response through either interval meters or direct load control.

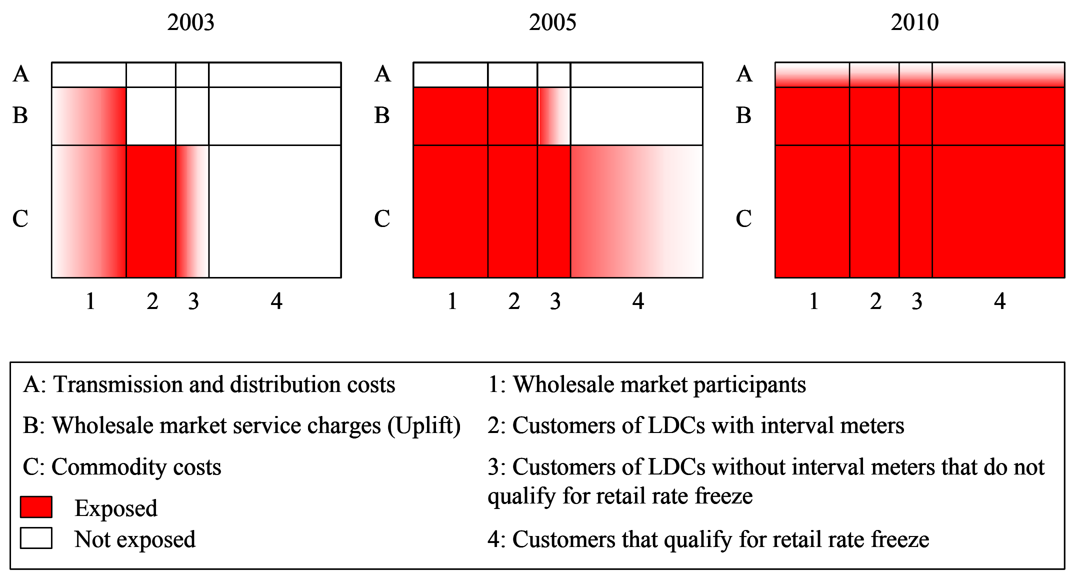


***Figure 11 – Illustrative Map of Potential Demand Response in Ontario Market in 2003, 2005 and 2010***

A representative illustration of the available demand response relative to the maximum potential over this same timeframe is shown in Figure 12. As indicated in the figure, under the current market situation and rules, Ontario's existing demand response potential represents perhaps 10% of the maximum potential. In 2005, based on the recommendations discussed below, Ontario could expect available demand response representing approximately 50% of the maximum potential. Finally, assuming the vision articulated above is realized, Ontario would realize 100% of its maximum demand response potential by 2010.

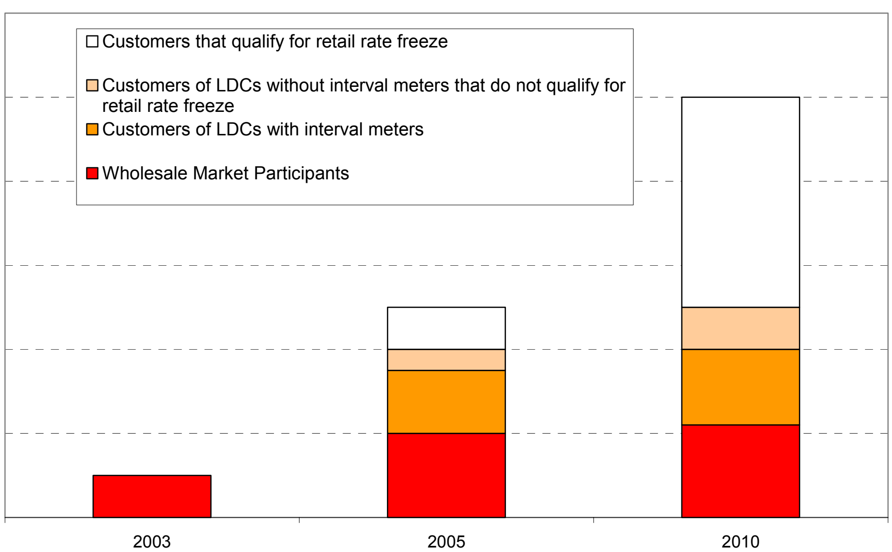


***Figure 12 – Available demand response relative to maximum potential in 2003, 2005 and 2010***

## Timing Considerations

***Summer of 2003 could be critical for demand response, as will 2005-6 timeframe***

Based on IMO forecasts, reserve margins for the summer of 2003 and the period leading into the summer of 2004 are expected to be adequate under normal weather scenarios and inadequate under extreme weather conditions[a]. Navigant Consulting's own forecast of Ontario's supply / demand balance is generally consistent with the IMO's forecast, but the summer of 2003 is forecast to be "tighter" than 2004. Beyond 2003, the critical period going forward is likely to be in the 2005 – 2006 time frame. The biggest risk in these forecasts is the nuclear return schedule and weather – extreme weather would increase demand and decrease reserve margins.

Based on Navigant Consulting's forecast of supply / demand balance, the greatest value for demand response is likely to occur this coming summer, when reserve margins will be relatively tight, even if the nuclear return schedule proceeds as planned. Demand response would be relatively less valuable during the summer of 2004 and would become relatively more valuable in the 2005 – 2006 time frame.

***Period through to 2006 is ideal opportunity to develop infrastructure for more significant demand response among all market segments in the long term***

This suggests that for those measures that are not achievable this summer, there is some time (but not too much time) available for careful planning and implementation. This provides time for the IMO, the OEB and the Government to make deliberate changes to the market structure and rules as needed, based on thorough research and analysis. But, given the potential risks with the nuclear supply schedule and for extreme weather, this analysis also suggests that these agencies should start the analysis as soon as possible to allow the implementation schedule to be expedited as needed in response to changes in the demand / supply balance.

Given this timing, Navigant Consulting recommends staged implementation of measures to increase demand response based on:

- ease of implementation,
- implementation risk
- operational risk
- "fit" with current market rules, and
- available resources.

Broadly speaking, the easiest programs with the least operational risk and best fit with current market rules should be implemented first. But there is still a need to begin exploratory / developmental work on longer-term initiatives as soon as

[a] *18 Month Outlook: An assessment of the Reliability of the Ontario Electricity System from January 2003 to June 2004*, Independent Electricity Market Operator, January 6, 2003

possible, otherwise the potential demand response resources from these measures won't be available on a timely basis.

***Staging considerations***

Given the market timing considerations above and recognizing that, even with appropriate price signals and access to enabling technologies, capturing the full potential demand response from a given market segment takes time, Navigant Consulting believes that an appropriate short term goal for the end of summer 2003 would be:

***Goals for summer of 2003***

- Capturing readily available demand response opportunities.
- Making the critical policy decisions and identifying the regulatory and market rule changes necessary to realize the vision articulated above.
- Beginning several pilots covering all market segments, including load sampling for direct load control, participation of embedded LDC customers in IMO demand response programs[a], use of aggregators and testing of alternative interval metering/pricing structure and enabling technologies for residential customers.

Over the medium term (say by 2005), and assuming 1) the necessary regulatory and market rule changes have been made, 2) enabling technology has been installed where cost effective, and 3) results are available from the various pilot programs, additional demand response can be expected from the following mechanisms:

***Medium term goals for 2005***

- Targeted customers and service providers will be much better informed through a comprehensive education campaign.
- The IMO will have a wide variety of demand response programs for wholesale market participants and accessible to other customers (through aggregators).
- Demand response through direct load control will be measured based on load sampling in those cases where interval metering is not cost effective.
- Customers with interval meters that are exposed to wholesale market prices will have a wide range of choices with respect to other enabling technologies, such as direct control and/or smart controls to help them manage demand in response to price.

[a] This could be effected through the establishment of rules for "quasi-wholesale market participation" for embedded LDC customers.

- Policies and rules regarding appropriate "tariffs" and installation of interval meters and other enabling technologies for low volume customers will be finalized.

- Installation of interval meters and other enabling technologies as appropriate among eligible or targeted low volume customers will have begun.

The vision articulated above represents the long-term end-state (ie, 2010) for demand response in Ontario.

## Co-ordination between the IMO, the OEB and the Government

***Areas for co-operation and co-ordination between Government, the OEB and the IMO***

Given the cross-cutting nature of the various issues and opportunities associated with demand response in the Ontario electricity market, there is a strong need for co-operation and co-ordination between the Government, the OEB and the IMO in order to:

- Establish and communicate a common vision for demand response in Ontario that is consistent with a competitive, vibrant wholesale and retail electricity market

- Identify the inter-jurisdictional issues with respect to demand response in the Ontario market

- Co-ordinate joint planning meetings and/or proceedings to gain stakeholder input on the critical policy decisions with respect to demand response

- Establish a common, integrated policy framework for demand response in the Ontario market

- Make the necessary changes in regulations, rules and codes in a deliberate, staged manner to achieve the vision

- Provide funding for and co-ordinate the necessary research, pilots and analysis with other agencies and market participants to facilitate demand response in the long term

- Co-ordinate or facilitate customer education as appropriate

- Interface with the EDA, customers, retailers and other service providers as appropriate.

One possible approach to achieve the necessary level of co-ordination would be the establishment of a joint Government, OEB and IMO Demand Response Task Force.

The need for a multi-lateral, integrated approach has been recognized in California and New York. New York's integrated demand response planning efforts include the New York Public Service Commission, the Governor's office, state agencies, power authorities and the NYISO. California's integrated response planning efforts include the California Public Utilities Commission, the California Power Authority, California Energy Commission, the CAISO, IOUs and other agencies. These two states have arguably the most comprehensive demand response programs and plans of all US states. In these and other markets, government, regulators, system operators, LDCs and demand response aggregators are dealing with issues associated with:

***Need for multi-lateral, integrated approach recognized in California and New York***

- Cost recovery
- Socialization of program incentives (if any)
- Improving the measurement approaches
- Jurisdictional access to different customer groups
- Recognition of the unique characteristics of demand response resources

## Recommended IMO Actions

The recommended actions for the IMO to encourage demand response are as follows:

1. ***The IMO should ensure that discrepancies between pre-dispatch and real time pricing and volatility of real-time prices are minimized to facilitate demand response***

   Among large customers, this discrepancy and volatility are perhaps the most significant impediments to demand response. The IMO should put the highest priority on addressing this issue because it is fundamental to increasing the level of demand response in Ontario.

2. ***The IMO should co-ordinate activities with the Government and OEB with respect to demand response***

3. ***The IMO should participate in generic demand response consultations or proceedings as required***

4. ***The IMO should effect the necessary changes to market rules as appropriate***

5. ***The IMO should continue the EDRP and consider allowing other customers to bid standby generators (up to a pre-determined maximum capacity) into the program***

   As currently structured, the EDRP does not incur significant "standing" charges and, as such, has minimal costs until it is absolutely needed (at which time customers are paid according to the terms of their unique contract and the demand response actually provided), hence the EDRP provides relatively inexpensive insurance against emergency measures such as load shedding. The New York ISO allows up to 125 MW of standby generators to participate in its EDRP, presumably based on the fact that their participation could forestall more drastic measures that would cause significantly more standby generators to operate (with greater resultant emissions impacts).

***6. The IMO should continue to aggressively encourage greater dispatchable load and operating reserve market participation by wholesale market participants***

The IMO has consulted extensively with customers to encourage greater dispatchable load participation. The IMO indicated that it was comfortable with the expected results from current efforts, but Navigant Consulting believes that a more proactive campaign to encourage dispatchable load would expedite customer participation and increase the level of demand response in the Ontario market. Since dispatchable load is more "visible" to the IMO than "self-dispatched" load and can be accurately reflected in its dispatch algorithm, greater levels of dispatchable load could help reduce prices (even with the same level of demand response among the customers that become dispatchable load).

***7. The IMO should implement the Hour Ahead Dispatchable Load (HADL) program for the summer of 2003***

Navigant Consulting believes it is important for the IMO to implement the HADL for this summer (even if only as a pilot) to gain valuable and timely experience beyond EDRP and existing dispatchable load opportunities. The HADL program is reasonably consistent with the IMO's current market rules and tools and will facilitate increased demand response, but participation may be limited. Navigant Consulting also notes that all other ISOs have programs with longer lead times than the IMO's current dispatchable load program and these longer lead times are generally consistent with the three hour notification that customers would receive under the HADL program (although some ISOs have or are planning programs with longer lead times). Baseline/measurement protocols could reflect the information and recommendations provided in Appendix B.

***8. The IMO should take a more aggressive role in educating customers, LDCs, retailers and potential demand response aggregators on demand response and load shifting***

Education is a key activity to increase demand response in Ontario and most customers are unaware of their options, available technologies and potential benefits of demand response and load shifting.

With respect to load shifting, even though the pre-dispatch signal is not always accurate and real-time prices can be volatile, general pricing patterns suggest load shifting can be a viable demand response strategy for some customers with potential to shift load on a daily basis.

### *9. The IMO (working with the OEB) should explore mechanisms to allow embedded LDC loads to participate in the EDRP and other IMO programs*

The NYISO has a successful program involving Load-Serving Entities providing demand response through the aggregation of "embedded" customers and demand response aggregation has proven effective in other markets at capturing incremental demand response resources. Note, however, that many of these programs provide fixed capacity payments to participating customers, which greatly encourages participation.

The IMO may need to "relax" certain conditions of their programs to allow LDC participation or develop simplified rules for a new class of "quasi-wholesale market participants" that are embedded.

### *10. The IMO should consider allowing LDCs and other market players, such as retailers, to serve as aggregators*

LDCs could develop their own programs for demand response provided that these programs can be packaged to be compliant with the "relaxed" rules as discussed above. Retailers serving embedded chain accounts across Ontario are well-placed to serve as aggregators of customer load for participation in the EDRP and other IMO programs but the current market rules make it impossible for retailers to play this role. Without significant changes in the respective role of retailers vis-à-vis LDCs in the wholesale market, it will be difficult to allow retailers to serve as aggregators without LDCs serving some intermediary role. To facilitate aggregation, the IMO could design and implement market price-based programs with longer notification periods (eg, day-ahead) in the longer term as appropriate given market needs and consistent with market evolution initiatives.

LDCs and other aggregators, such as retailers, would be expected to recover the costs for and compensated for the risks of providing aggregation and co-ordination services from participating customers[a]. As an example, the NY PUC allows LDCs to retain 10% of the demand response payments to participating customers to cover their costs and provide an incentive to encourage greater participation and demand response among their customers.

[a] Cost recovery by LDCs for demand response activities would likely be governed by the OEB, but the IMO market rules can directly impact the ability of LDCs to aggregate demand response.

### *11. The IMO should explore the costs and benefits of introducing one or more Economic Demand Response programs*

Navigant Consulting understands that the IMO is currently undertaking its own independent assessment of economic demand response. Analysis undertaken by Navigant Consulting and described in *Valuing Demand Response* on page 56 suggests that there are situations when it may be economically efficient to pay some customers to reduce their demand. Most other ISO's have some form of economic demand response programs. The key questions to consider in this assessment include:

- How much would this cost (assuming reasonable expectations of pricing, participation, frequency and duration) and what would be the overall impact on payments to generators, market prices and market dynamics?
- How would the costs of any economic demand response programs get recovered?
- What impact would the introduction of one or more economic demand response programs have on other market-driven demand response programs?

## Possible Government Actions

In addition to co-ordinating demand response activities with the OEB and IMO and with other government initiatives related to demand-side management, the following suggested actions for the Government would encourage greater demand response in the Ontario market:

### *12. The Government could direct the OEB to undertake a generic proceeding on demand response to consider the various issues impeding demand response and develop appropriate policies and codes to encourage greater demand response in the Ontario market*

If appropriate, the scope of this generic proceeding could be expanded to address broader demand-side management issues.

### *13. The Government could assess the costs and benefits of the Government or a government agency funding some of the necessary infrastructure costs and pilot programs to encourage demand response in the Ontario market*

Given the current market environment, market rules, uncertainty regarding cost recovery mechanisms and rate cap regime for LDCs, there are significant barriers to a "market-based" solution in the short term.

Demand response has a long lead time, and if infrastructure investments and pilot programs are delayed, the beneficial impact of demand response to all market participants will be correspondingly delayed.

Significant benefits are likely to accrue to the Government from any short-term and medium-term demand response given the Government's financial obligation under the retail electricity price freeze.

Demand response will mitigate market price volatility and create a more favourable environment for re-introducing market prices to low volume and designated customers in 2006.

As appropriate, the Government could consider issuing directives with respect to load management to the OEB as allowed under Bill 210 (Sections 27.1 and 28.1). The directives could address several of the issues discussed in this report. In addition to issuing directives to the OEB, the Government could also encourage the IMO and/or effect changes in legislation and regulation to facilitate demand response.

***14. The Government could seek input from the Ministry of Environment on the potential to use standby generators in EDRP and explore special permitting exemptions regarding use for EDRP participation or confirm that existing permitting requirements would allow EDRP participation***

## Possible OEB Actions

In addition to co-ordinating demand response activities with the Government and IMO, the following suggested actions for the OEB would encourage greater demand response in the Ontario market:

***15. The OEB could take the lead role in a generic demand response proceeding and could effect necessary code changes as appropriate at the retail level***

***16. The OEB could consider making installation of interval meters down to 200 kW (or 100 kW) for existing customers mandatory by the summer of 2004***

***17. The OEB could work with the Government and EDA to design pilot programs intended to determine the most cost-effective means of introducing interval meters and enabling technologies in the low volume customer segment***

Key pilot parameters would include:

- Consistency with government policy with respect to the retail price freeze (eg, commodity costs for participants would not exceed 4.3 cents/kWh)
- Clarification of funding sources for any "buy-down" from 4.3 cents/kWh for participating customers that provide demand response
- Complementary to pilots underway in other jurisdictions (eg, California) to minimize overall costs and maximize learnings from the pilots.

***18. The OEB could work with government and service providers to design pilot / demonstration projects to help communicate the benefits of and mechanisms for demand response among the various segments (eg, retail, hospitality, industrial, offices, etc.) of larger embedded LDC customers***

This work should also identify existing customers who have already implemented enabling technologies and are providing demand response (if this is done as a first step, it will likely reduce the number of "new" pilot/demonstration projects needed to provide broad segment and market coverage).

***19. The OEB could consider developing a methodology to allow determination of fair and equitable time-differentiated distribution charges to be undertaken by a representative sample of LDCs as part of their upcoming cost allocation studies***

The sample and methodology for this analysis should be sufficiently robust to allow results to be extrapolated to other LDCs with minimal error and implementation risks if deemed appropriate.

***20. The OEB could explore the potential costs and benefits of requiring LDCs to charge uplift on an hourly basis for customers with interval meters***

LDCs have hourly consumption data and hourly uplift data, but final uplift charges are delayed (hence there may be a need for some form of interim estimation/accrual accounting). The issue of how to effect these changes in a rate cap environment would need to be addressed. If deemed to be cost-effective, the OEB should make the necessary changes in the appropriate codes.

***21. The OEB could review and clarify the role of LDCs in facilitating demand response vis-à-vis other market participants***

In this review, the OEB would need to consider the most appropriate short-term and long-term role for LDCs given the current market situation and dynamics. It may be appropriate for LDCs to take a more active role on an interim, transitory basis in the short-term and, as other market participants begin to take a more active role in demand response, LDCs could play more of a facilitation role in the longer term.

## Customer Education and Outreach Activities

***Education of customers and service providers is critical to maximizing demand response***

Education of customers, service providers and other market intermediaries is critical to maximizing demand response within available rules and infrastructure. The IMO and retailers are well placed to educate wholesale market participants. LDCs and/or retailers are well placed to educate embedded customers. However, there may be limited funds available within some of these entities to support a major education effort; funding may need to be addressed

The timing of and need for education will be dependent on when market-based pricing and enabling technologies are in place. Wholesale market participants are likely to be relatively knowledgeable and sophisticated; the key information needed will likely be details on IMO programs. Large embedded LDC customers with interval meters are generally less knowledgeable. They should be targeted, along with their service providers, to encourage demand response for the summer of 2003. Joint workshops with customers and service providers would serve to educate and facilitate.

***The IMO should continue with its public appeals during periods of very high demand***

In the absence of a market-based price signal for low volume and designated customers, the IMO should continue with its public appeals during periods of very high demand. Primary and secondary research on which enhancements, if any, would improve the effectiveness of IMO appeals should be considered.

If and when a dynamic price signal and enabling technology are available for low volume and designated customers, a significant mass market education effort would be beneficial to maximize participation and satisfaction. The IMO could facilitate this process through a more readily accessible price feed, although several service providers are already collecting and providing this information.

***Provincial Government could set the example through aggressive demand response at its facilities***

The provincial Government could take a leadership role in demand response by working to maximize the demand response of its various facilities throughout Ontario, regardless of whether they are interval metered. The provincial Government could also work closely with designated customers to help them maximize their demand response potential.

## Interval Meters for Medium-Sized Customer

***Recommend the OEB consider making installation of interval meters down to 200 kW mandatory***

Navigant Consulting recommends that the OEB consider making installation of interval meters down to 200 kW (or 100 kW) for existing customers mandatory by the summer of 2004. Preliminary analysis suggests this would be cost-effective even under the most conservative assumptions. Additionally, this group of customers is already exposed to wholesale market prices and interval meters would provide them with the opportunity to better manage their demand and electricity costs. Although lowering the threshold for interval metering would be inconsistent with Market Design Committee (MDC) recommendations, the current market situation is markedly different than that envisaged by the MDC.

This initiative would likely cost in the range of $20 M and would facilitate demand response from customers estimated to represent approximately 10% to 12% of market demand.

Most utilities have included the costs of interval metering for customers with peak demand > 1000 kW in their rate base (although customers typically had to pay for necessary communication infrastructure, such as bringing a shared telephone line to the meter). Hence, all customers will eventually pay for these interval meters through their rates (unless these costs are specifically allocated to the customer class receiving the interval meters). Using a similar approach for any new interval meters, LDCs would not be able to recover incremental costs given what is effectively a distribution rate cap under Bill 210. LDCs could collect the costs associated with installing and operating any new interval meters as a regulatory asset[a], but LDCs' financial resources are limited.

***Could share the costs of interval metering between customers and Government***

Given the potential benefits that the installation of interval meters would have on demand response from this customer group, consideration should be given to sharing the costs for such meters between:

1) those customers receiving the interval meters and

2) the Government (whose financial obligations from the retail price freeze would be reduced to the degree that wholesale prices are reduced through greater demand response from this customer group).

The OEB could consider implementing the initiative in stages – 500 kW for this summer and 200 kW by next summer – or target the most price responsive customer segments first.

***Co-ordinated procurement/ installation among LDCs could reduce overall costs for interval meters***

Given the potential magnitude of such a large scale deployment and recognizing 1) the current resource constraints within most LDCs and 2) the benefits of expedient installation, consideration should be given to some form of outsourcing / competitive procurement for the interval meter installation. LDCs with similar metering specs and systems could be encouraged to pool their requirements and competitively tender the installation for greater economies of scale. Meter data management could become an issue depending on the individual LDCs internal processes and system capacity. These issues suggest there is a need to re-assess the issue of competitive metering, which could reduce the total costs for this and subsequent tranches of interval metering.

[a] In this context, regulatory assets are those assets for which regulated LDCs will be allowed to earn a prescribed rate of return after the expiration of the distribution rate cap effected through Bill 210.

### *Interval Meters for New Homes*

The Government is currently considering the implementation of a policy requiring interval meters to be installed at all new homes. Assuming $400/interval meter (versus $75/meter for a standard meter) and 75,000 new homes constructed in Ontario each year[a], such a policy would cost up to $25M each year, plus additional data management and settlement costs.

***Government considering a policy requiring interval meters for all new homes***

Navigant Consulting believes that providing interval meters for new homes would increase demand response in the market (provided customers were also provided with a market-based time varying price signal), but the specific benefits are not known with any level of certainty, nor are the optimal rate/product offerings to maximize the benefits known. Note that most studies from other jurisdictions are based on voluntary participation by customers and hence, any of the results of these studies have to be treated with caution given the sample bias (compared with mandatory deployment as being considered in Ontario).

***With appropriate price signals, interval metering will provide benefits, but the specific benefits are not known with any certainty***

Questions relating to the optimal technology infrastructure and tariffs under a retail price freeze regime can be addressed through a series of multi-LDC pilot programs[b]. Pilots could cover new homes, existing homes and different rate/product offerings (eg, TOU, difference from NSLS, CPP-F, CPP-V). Information from other markets, such as California, can also complement findings from any local pilots. Based on this, Navigant Consulting suggests two pilot programs be considered:

- one pilot with interval meters, "smart" thermostats and similar controls and some form of spot price pass-through (with a 4.3 cents/kWh cap) and
- one pilot with interval meters only and some form of spot price pass-through (with a 4.3 cents/kWh cap).

***Consider two pilots with interval meters AND dynamic pricing – one with enabling technologies and one without***

During the course of the pilot, the OEB should also develop better estimates of the secondary benefits to LDCs, such as avoided manual meter reading costs, better outage management, reduced high bill complaints, etc., and incremental costs for LDCs in terms of data management and ability of LDCs to manage the incremental data volumes. All of this information can serve as an input to cost allocation and cost recovery policies.

One possible alternative view supporting mandatory deployment would be that even though the optimal rate/product offerings are not known today, it is still

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[a] CMHC Housing Outlook, National Edition, First Quarter 2002

[b] Navigant Consulting understands that several LDCs are currently installing interval meters at customers' homes on a trial basis. Without a co-ordinated plan, any learnings from these installations are likely to be statistically unreliable.

worth installing interval meters today in order to avoid a "lost opportunity" (ie, if an interval meter was not installed, society would have to incur additional costs to install an interval meter eventually). Given the low costs of conventional meters and expectations that interval meters costs will continue to decline, Navigant Consulting does not support this view. Instead, Navigant Consulting believes it would be better to spend less money to firm up the costs and benefits and refine the customer offer through carefully designed pilots.

***Likely more cost-effective to pursue interval meters for > 200 kW customers***

Navigant Consulting expects it would be more cost-effective to pursue interval meters for > 200 kW customers for the following reasons:

- An interval meter for a residential customer will make up to 4 kW of load price-responsive, at a cost of $100/kW of load "accessed" ($400/4 kW) whereas an interval meter for a customer with demand > 200 kW will make, on average 400 kW of load price-responsive, at a cost of $5/kW of load "accessed" ($2000/400 kW). Ignoring the pricing issues associated with facilitating demand response under a price freeze and data management issues associated with the sheer volume of meter data generated, the relative elasticity of residential customers would have to be ten times greater than for customers with peak demand > 200 kW for residential customers. Evidence from numerous elasticity studies suggests that this is not the case.

- Installation of interval meters for > 200 kW customers will contribute to achieving maximum demand response from approximately 10% of market volume in perhaps five years (assuming two years for installation of meters plus another two or three years for additional enabling infrastructure from service providers and customer experience/knowledge/comfort, recognizing most of the customers in this segment are already exposed to wholesale market prices). Interval meters for new homes will only facilitate demand response from customer representing between 2% and 3% of overall market volume over a five year period[a].

### *Direct Load Control by LDCs*

***Reactivating water heater load control programs is an attractive short-term opportunity***

The Government, OEB and IMO should explore mechanisms to allow direct control water heaters by LDCs in order to provide incremental demand response for the summer of 2003 and beyond. Based on survey responses from LDCs and extrapolating to the entire population of LDCs, Navigant Consulting estimates that between 30 to 60 MW of direct load control could be in place for the summer of 2003 (assuming an aggressive implementation and marketing plan).

[a] Assuming 75,000 homes per year, each using 10 MWh annually. 75,000 x 10 x 5 years = 3.75 TWh, which represents between 2% and 3% of Ontario's total electricity consumption of 150 TWh. Expansion of this policy to all new customers would increase market coverage to perhaps 5% or 6%, net of interval metering required under current market rules.

Demand response for direct load control program can be accurately measured using load sampling techniques, interval meters are not required for all participants. To reduce load sampling costs, it may be possible to develop an multi-LDC sample frame of LDCs using the same control strategy (ie, shut off water heaters for up to x hours when prices are greater than $80 / MWh or shut off water heaters between 2pm and 6pm every day).

***Can use load sampling to determine demand response impacts***

Direct load control programs do not do not need to be directly integrated with the IMO, but LDCs could indicate their demand response strategy and pricing thresholds so that the IMO could incorporate the expected impact into its short term forecast. Some level of discounting would likely be appropriate in the short term until the actual impact is determined with greater accuracy.

***IMO could incorporate expected impact from load control programs in its forecast***

NY allows Load Serving Entities to keep 10% of revenue from ISO programs as an incentive to encourage participation and aggregation. The OEB could consider a similar model in the short term for Ontario, but would need to determine the appropriate percentage to encourage investment by LDCs.

As the primary beneficiary of demand response from this customer group while the retail price freeze is in effect, the Government could consider funding the necessary capital, operating and "incentive" costs for these programs. While Navigant Consulting believes that LDCs and their affiliates are the most appropriate market participants to capture this opportunity in the short term (given their ownership of the water heaters, controllers and control system), the OEB should consider mechanisms to allow other market players (eg, retailers and other service providers) to capture additional opportunities in the future .

***Given expected price impacts, Government could fund reactivation and operating costs for load control programs***

# APPENDIX A: DETAILS OF OTHER ISO DR PROGRAMS

Navigant Consulting investigated the demand response programs in several jurisdictions. A summary of the various programs for New York, New England and PJM (deemed to be the most relevant to this study), is provided in this appendix.

## Demand Response Programs in New York

NY ISO has three demand response programs currently in place:

- Day Ahead Demand Response Program (DADRP)
- Emergency Demand Response Program (EDRP)
- ICAP Special Case Resources Program (ICAP/SCR).

Each program is described in detail below.

## Day Ahead Demand Response Program (DADRP)

In this program, demand response is bid into the Day-ahead market. The bid must include an LMP (min $50/MWh) above which load would curtail and may include a curtailment initial cost. The bid must specify duration of curtailment as a contiguous strip of time of no more than 8 hours. A single customer can bid multiple strips in one day.

| | |
|---|---|
| Position in Emergency Response Stack | ▪ Part of day-ahead scheduling.<br>▪ Before ICAP/SCR and EDRP. |
| Participant Requirements | ▪ Can be interruptible load or small on-site generation.<br>▪ 1 MW increments, can aggregate.<br>▪ Hourly Interval meter. Accuracy not specified (presumably +/- 2%, as for EDRP) |
| Notification Method and Lead Time | ▪ Bid required by 5am day-ahead, notice by noon (day ahead). |
| Minimum Duration | ▪ As bid. |
| Price Paid to Customer and Non-Compliance Penalty | ▪ Price paid to customer is greater of bid $/MWh or Day ahead LMP.<br>▪ Bids can set Day ahead LMP<br>▪ An LSE/CSP with a Demand Side Resource that curtails Load will receive a rebate from the NYISO for the curtailed amount of Load priced at the Day-Ahead LMP (with the exceptions of Small Generators) as an Incentive.<br>▪ Non-compliance penalty is greater of Day ahead or Real-time LMP + 10% if incentives apply or greater of Day ahead or Real-time LMP if incentives don't apply (i.e. for generators). |
| Cost Recovery | ▪ Distributed among zones based on static probability that no constraint will occur or that a constraint will occur upstream or downstream of the zone.<br>▪ Recovered from all transmission customers in the zone based on their share of energy use in that zone in that month. |
| Participation | ▪ 24 participants in 2002. |

## Emergency Demand Response Program (EDRP)

In this program, the ISO calls for voluntary load reduction in an emergency situation. Participants who respond in time are paid for their actual curtailment.

| | |
|---|---|
| Position in Emergency Response Stack | ▪ The NYISO will declare an Alert State, or Major Emergency for real-time shortage of Operating Reserve, and activate all available in-state generating resources to re-establish the Operating Reserve. If required levels of real-time Operating Reserves cannot be re-established, the NYISO will utilize the EDRP (after ICAP/SCR) to re-establish real-time Operating Reserves. |
| Participant Requirements | ▪ Retail end users can be accommodated through one of four types of Curtailment Service Providers (CSPs): LSEs; approved Curtailment Customer Aggregators; as a Direct Customer of the NYISO themselves, and As a NYISO-approved Curtailment Program End Use Customer<br>▪ Min 100 kW per zone, can aggregate. Aggregates of load must be min 0.5MW. Aggregators must accept full responsibility for payments to and penalties applied to members of aggregate.<br>▪ Up to 25MW of small retail load can be aggregated with curtailment measured under alternative methods<br>▪ Hourly Interval meter with accuracy of +/- 2%. |
| Notification Method and Lead Time | ▪ burst e-mail or phone call<br>▪ day-ahead or earlier in-day advisory given when possible (advisory does not activate program), 2 hour notice (if possible) |
| Minimum Duration | ▪ 4 hours. If curtailment is needed for less than 4 hours, CSP will be paid for at least 2 hours |
| Price Paid to Customer and Non-Compliance Penalty | ▪ Price paid to customer is greater of $500/MWh or Real-time LMP.<br>▪ Min $500/MWh price can set Real-Time LMP.<br>▪ No non-compliance penalty. |
| Cost Recovery | ▪ Recovered from all transmission customers in the affected zone(s) based on their share of energy use in that zone(s) in that month. |
| Participation | ▪ 1711 participants with 1481 MW in 2002. Average demand reduction during summer 2002 curtailment events was approximately 670 MW. |

## ICAP Special Case Resources Program (ICAP/SCR)

In New York, there is an Installed Capacity market where capacity providers receive ICAP payments for available capacity. In the ICAP Special Case Resources Program, Special Case Resources get ICAP payments, and are called on to provide energy (demand reduction) in emergencies. SCRs submit strike price offers that set the price at which they provide demand reduction.

| | |
|---|---|
| Position in Emergency Response Stack | ▪ Called when there's an anticipated shortage in operating reserve, before EDRP |
| Participant Requirements | ▪ Min 100 kW demand reduction. ICAP credits can only be claimed in increments of 100 kW (599 kW is rounded down to 500 kW), can be aggregated.<br>▪ Must not be visible to ISO's market information system<br>▪ A resource interface party (RIP) can act as an intermediary between ISO and Special case resource.<br>▪ Hourly Interval meter. Accuracy not specified (presumably +/- 2%, as for EDRP) |
| Notification Method and Lead Time | ▪ burst e-mail or phone call to RIP (or SCR directly)<br>▪ RIP must confirm receipt of notification within 1 hour by internet or telephone<br>▪ RIP can communicate notice to SCR in any agreed upon manner<br>▪ Day ahead warning (21 hour if by 3PM or 24 hour), 2 hour notice |
| Minimum Duration | ▪ resource must be capable of providing 4 hours. Actual duration will be as needed (with SCR paid for at least 4 hours). |
| Price Paid to Customer and Non-Compliance Penalty | ▪ SCR paid $/kW market value of ICAP up front<br>▪ Payment for energy reduction based on strike price (guaranteed their minimum bid up to EDRP value of $500/MWh)). Strike price can set Real-Time LMP if at least 1 MW of SCR Capacity is needed to satisfy the total reserve requirement<br>▪ Non-compliance has a UCAP impact and possible deficiency payments. |
| Cost Recovery | |
| Participation | |

## Other NY Demand Response Points

- LSEs have and/or are developing their own curtailment programs for managing their load and increasing reliability of the local electric system. The programs above have been designed to be compatible with these.
- Demand-side resources may no longer participate in both the ICAP and EDRP. Demand-side resources may participate in both the DADRP and EDRP. If bid accepted in DADRP, DADRP commitments are settled first, and any load reduction beyond DADRP required levels are paid at the EDRP rates.

# Demand Response Programs in New England

NEPOOL has three demand response programs currently in place:

- Real-Time Demand Response Program
- Real-Time Price Response Program
- Interruptible Load

## Real-Time Demand Response Program

The ISO instructs retail customer to reduce demand. Customer is paid if they comply with instruction. Essentially, this is an emergency demand response program. The program is only in place on non-holiday weekdays from 7:00 to 18:00.

| | |
|---|---|
| Position in Emergency Response Stack | ▪ Activated at Action 12 of NEPOOL Operating Procedure No. 4. As part of Action 12, ISO initiates voltage reduction<br>▪ End of stack |
| Participant Requirements | ▪ Retail customers are enrolled in program through NEPOOL participants (participants get paid by ISO and pay to retail customers)<br>▪ Min 100 kW demand reduction.<br>▪ Interval metering required. |
| Notification Method and Lead Time | ▪ Participant must be willing and able to reduce demand within 30 min. of receiving direction from ISO. |
| Minimum Duration | |
| Price Paid to Customer and Non-Compliance Penalty | ▪ Enrolled retail customers paid a reservation fee based on 30min op res. hourly clearing price, and are eligible to receive an ICAP credit.<br>▪ For actual interruptions, price paid is Energy Clearing Price multiplied by congestion multiplier. This price can not exceed $100US |
| Cost Recovery | ▪ MCP portion of interruption payments allocated to NEPOOL participants based on pro rata share of load<br>▪ Congestion multiplier portion of interruption payments collected from participants with Network Load distributed in same manner as congestion costs. |
| Participation | ▪ Load reductions not triggered in 2002. |

## Real-Time Price Response Program

The ISO opens a window for retail customers to voluntarily reduce demand. This program is only in place on non-holiday weekdays from 7:00 to 23:00

| | |
|---|---|
| Position in Emergency Response Stack | ▪ Window for voluntary demand curtailments opened when results of unit commitment by ISO forecasts MCP greater than $100<br>▪ 2nd in stack |
| Participant Requirements | ▪ Retail customers are enrolled in program through NEPOOL participants (participants get paid by ISO and pay to retail customers)<br>▪ Min 100 kW demand reduction.<br>▪ Interval metering required. |
| Notification Method and Lead Time | ▪ Notification can be through Internet Based Communication System or through a "low tech" option which uses e-mail, fax, pager messaging and notification posted on ISO external web site |
| Minimum Duration | |
| Price Paid to Customer and Non-Compliance Penalty | ▪ Region-wide MCP (not LMP). |
| Cost Recovery | ▪ Recovered from all NEPOOL participants based on pro rata share of load. |
| Participation | |

## Interruptible Load

This is a standard interruptible rate program. Retail customers receive special interruptible rates from wholesale energy supplier.

| | |
|---|---|
| Position in Emergency Response Stack | ▪ Activated in early Actions of NEPOOL Operating Procedure No. 4.<br>▪ 1st in stack |
| Participant Requirements | ▪ Hourly Interval meter. |
| Notification Method and Lead Time | ▪ Loads divided into three categories based on notification time prior to interruption.<br>▪ Maximum 12 hours |
| Minimum Duration | ▪ Depends on load category |
| Price Paid to Customer and Non-Compliance Penalty | ▪ No specific price paid for interruption, but these loads pay a special interruptible rate for all energy consumed. |
| Cost Recovery | |
| Participation | |

## Other New England Demand Response Points

- Interruptible Load program expected to be replaced with expanded DR programs for both day-ahead and real-time markets.
- ISO-NE believes that eventually, no payments will be required for DR, but in the interim, because of barriers to retail customers facing real-time price signals, DR programs need to pay for DR.
- ISO-NE has engaged in several steps to increase participation:
    - Improving and introducing new DR programs such as:
        - Day-ahead demand response (new)
        - Real-time 30-min demand response
        - Real-time 2 hour demand response (new)
        - Real-time price response
        - Real-time profile response (new)
    - Creation of separate department within ISO to focus on DR
    - Forums to educate industry stakeholders

# Demand Response Programs in PJM

PJM has three demand response programs currently in place:

- Economic Load Response Program
- Emergency Load Response Program
- Active Load Management (ALM)

## Economic Load Response Program

PJM provides an incentive (as a payment for load reduction) to end-use customers or curtailment service providers to enhance the ability and opportunity for reduction of consumption when PJM Locational Marginal Prices ("LMP") prices are high. This program came into effect on June 1st 2002, and is scheduled to terminate on Dec 1st 2004 unless members vote to extend it. The program has both a Real-time and Day ahead option.

### *Day-Ahead*

| | |
|---|---|
| Position in Emergency Response Stack | ▪ End-use customers bid load reduction into Day ahead market. The demand reduction bid includes the day-ahead LMP above which the end-use customer would not consume, and could also include a start-up cost and/or a minimum number of contiguous hours for which the load reduction must be committed. |
| Participant Requirements | ▪ PJM Member, or any existing PJM Member may act as a third party for non-members, in which case the third party will be referred to as the Curtailment Service Provider (CSP).<br>▪ Bid must involve minimum increments of 100kW.<br>▪ End-use customers on LMP-based contracts with energy suppliers are ineligible to participate.<br>▪ Hourly Interval meter with accuracy of +/- 2%. |
| Notification Method and Lead Time | ▪ Bid submitted day ahead. |
| Minimum Duration | ▪ As bid. |
| Price Paid to Customer and Non-Compliance Penalty | ▪ Reimbursement for reducing load is based on kWh committed to in day-ahead market.<br>▪ If PJM accepts a bid when day ahead LMP <$75/MWh, PJM will pay day ahead LMP less an amount equal to the applicable generation and transmission charges. If PJM accepts a bid when day ahead LMP >=$75/MWh, PJM will pay day ahead LMP<br>▪ Total payments to end-use customers or their representatives (LSEs/CSPs) can not be less than the total value of the load response bid, including any submitted start-up cost. Any shortfall will be made up through normal, day-ahead operating reserves. |
| Cost Recovery | ▪ PJM recovers LMP less amount equal to generation and transmission charges from the LSE that otherwise would have the load that was reduced. The amount equal to the generation and transmission charges are recovered from all load within the zone in which the load was reduced. If an LSE has a full requirements and/or load-following contracts for generation supply, the obligation to pay flows to the generation supplier. |
| Participation | |

### *Real-Time*

| | |
|---|---|
| Position in Emergency Response Stack | ▪ End-use customers participating in the Economic Load Response Program may choose to reduce load whenever their zonal LMP dictates that it is economically beneficial for them to do so or may choose to be dispatched by PJM. |
| Participant Requirements | ▪ PJM Member, or any existing PJM Member may act as a third party for non-members, in which case the third party will be referred to as the Curtailment Service Provider (CSP).<br>▪ Bid must involve minimum increments of 100kW.<br>▪ End-use customers on LMP-based contracts with energy suppliers are ineligible to participate.<br>▪ Hourly Interval meter with accuracy of +/- 2%. |
| Notification Method and Lead Time | ▪ The end use customer or its representative (LSE/CSP) shall send an email to PJM concurrent with or up to one hour immediately prior to beginning the reduction, and another concurrent with or up to one hour immediately prior to the end of their load reduction. |
| Minimum Duration | ▪ Determined by customer, or by PJM (based on customer bid) if customer is dispatched |
| Price Paid to Customer and Non-Compliance Penalty | ▪ Reimbursement for reducing load is based on the actual kWh relief provided in excess of committed day-ahead load reductions plus the adjustment for losses.<br>▪ If Real-time LMP <$75/MWh PJM will pay real time LMP less an amount equal to the applicable generation and transmission charges.<br>▪ If Real-time LMP >=$75/MWh PJM will pay real time LMP<br>▪ If PJM dispatches load reduction, payment will not be less than the total value of the load response bid, including any submitted start-up cost. |
| Cost Recovery | ▪ PJM shall recover LMP less amount equal to applicable generation and transmission charges from the LSE that otherwise would have the load that was reduced. The amount equal to the generation and transmission charges is recovered from all loads within the zone in which the load was reduced. If an LSE has a full requirements and/or load-following contracts for generation supply, the obligation to pay flows to the generation supplier. |
| Participation | |

## Emergency Load Response Program

In this program, end-use customers are compensated by PJM for voluntarily reducing load during an emergency event.

| | |
|---|---|
| Position in Emergency Response Stack | ▪ After declaration of Maximum Emergency Generation and before ALM steps 1 and 2 |
| Participant Requirements | ▪ PJM Member, or any existing PJM Member may act as a third party for non-members, in which case the third party will be referred to as the Curtailment Service Provider (CSP).<br>▪ Generators and Loads (> 100 kW).<br>▪ Must be capable of receiving PJM notification to participate during emergency conditions.<br>▪ Hourly Interval meter with accuracy of +/- 2%. |
| Notification Method and Lead Time | ▪ Notification through PJM web page, Edata, Burst e-mail, and All-call messages |
| Minimum Duration | ▪ 2 hours. |
| Price Paid to Customer and Non-Compliance Penalty | ▪ Price paid to customer is greater of $500/MWh or zonal LMP.<br>▪ No non-compliance penalty. |
| Cost Recovery | ▪ All purchasers pay proportional to difference from day-ahead to real-time consumption |
| Participation | |

## Active Load Management (ALM)

LSEs or others act as ALM providers. They receive ALM credits daily for the amount of curtailment/ALM they can provide. Customers can be curtailed a maximum of 10 times in a planning period. ALM providers can contract with customers for interruptible/curtailable load however they wish. The program is only in place during the hours of 12PM to 8PM on weekdays, excluding holidays.

| | |
|---|---|
| Position in Emergency Response Stack | ▪ After Emergency and economic load response, and after voltage reductions and maximum emergency generation. |
| Participant Requirements | ▪ ALM provider must be capable of reducing load of all ALM customers without additional approval<br>▪ All ALM customers must be metered, and the ALM provider must provide customer specific ALM credit information and compliance and verification info<br>▪ Can use direct load control, firm service level (down to) and guaranteed load drop (down by) |
| Notification Method and Lead Time | ▪ PJM notifies ALM provider, who is responsible for notifying customer<br>▪ 2 types of customer: short lead time is 1 hour or less, long lead time is 2 hours or less |
| Minimum Duration | ▪ None specified. 6 hour maximum. |
| Price Paid to Customer and Non-Compliance Penalty | ▪ No actual payment is made to LSE<br>▪ Each LSE is responsible for providing a certain amount of capacity under the UCAP system. ALM credits reduce this obligated quantity. Reducing obligation allows LSE to contract for less capacity, or to sell excess capacity at spot prices.<br>▪ What LSEs can offer customers for ALM is not determined by PJM.<br>▪ Any compliance deficiency penalty will be calculated as: Compliance Deficiency Value *Daily Capacity Deficiency Rate from RAA Schedule 11 * 365 / 10. |
| Cost Recovery | ▪ Penalties from compliance deficiency will be used to pay ALM providers that over-complied. |
| Participation | |

## Other PJM Demand Response Points

- The economic load reduction program purposefully incorporates incentives greater than strict economics would provide for the same curtailment. This is justified to overcome initial barriers to end-use customer load response. This program is not intended to be a permanent fix to the lack of load response seen in the PJM markets today. The designers of this program contemplate that when the existing market barriers are removed and end-use customers are better able to respond to real time prices, the need for this program and others like it will disappear.
- PJM will also consider customers without hourly metering for participation in a pilot program for up to two years per customer, provided the customers or their representatives propose an alternate method for measuring hourly load reductions. Alternate measurement mechanisms will be approved by PJM on a case-by-case basis. Participation in the non-hourly metered customer pilot will be limited to 25MW aggregate load reduction over the PJM region and across all load response programs, and with the sole exception of the requirement for hourly metering, will be subject to the same rules and procedures as the applicable load response program in which the customer has enrolled. Following the 2-year pilot period, each alternate method must be approved through the normal PJM stakeholder process in order to continue to be used.
- For the economic load reduction program, an end-use customer or its representative (LSE/CSP) will accumulate credits for energy reductions in those hours when the energy delivered to the end-use customer is less than the end-use customer's CBL at the corresponding hourly rate. In the event the end-use customer's hourly energy consumption is greater than then the CBL, the end-use customer or its representative (LSE/CSP) will accumulate debits at the corresponding hourly rate for the amount the end-use customer's hourly energy consumption is greater than the CBL. However, in no event will the end-use customer's (or its representative's) credit be reduced below zero on a daily basis.
- For the economic load reduction program, If the total amount of recoverable charges reflecting generation and transmission charges for the entire program exceeds $17.5 million in a year, thereafter participants will receive LMP less an amount equal to the applicable generation and transmission charges regardless of the level of LMP.
- An ALM customer may participate in the Economic Load Response program during ALM events as long as the customer's ALM contract explicitly excludes payment or credit for energy not consumed during ALM events.
- In all cases, the applicable zonal or aggregate LMP is used as appropriate for the individual end-use customer.
- PJM staffing a new department within its market services division to deal exclusively with integrating demand side participation in the market.

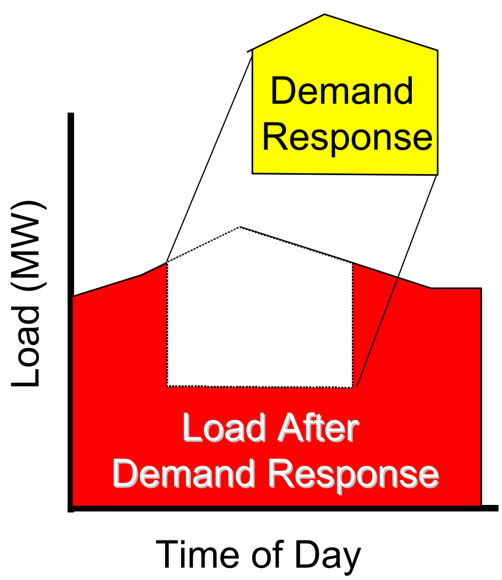
# APPENDIX B: MEASUREMENT APPROACHES

Determining the actual amount of demand response provided is critical to all demand response programs. There are many techniques currently in use, although most are variations of a few basic methods. A comprehensive evaluation of the various techniques was performed for the California Energy Commission. The findings of this evaluation have been documented in a report entitled "Protocol Development for Demand Response Calculation: Draft Findings and Recommendations"[a]. The results from this study served as the primary source for the information provided below.

Only baseline calculation methods for interval-metered sites are discussed in the study for the California Energy Commission. There is also the potential for sampling for aggregated, controlled loads such as water heaters. NY and California have pilots in this area, and PJM allows up to 25MW of aggregated demand response to be measured by alternate means. Such sampling could be applied for water heaters in Ontario and would help to minimize the costs of re-activating this resource.

The objective of all demand response measurement approaches and baseline calculation methodologies is to accurately determine what the customer's load would have been if the customer had not undertaken some form of demand response action. This is shown schematically in Figure 13.

***Figure 13- Illustration of baseline calculation objectives and issues***




**Measurement approach must accurately predict what load would have been**

- **Fair to all parties**
- **Reflect factors influencing customer load**
- **Simple, but not too simple**

This section provides a discussion of the key elements of any baseline calculation methodology, followed by highlights of the CEC study and a summary of the methodologies used by other ISO. Finally, recommendations for baseline calculation methodologies for Ontario are presented.

[a] *Protocol Development for Demand Response Calculation, Draft Findings and Recommendations,* prepared for California Energy Commission, August 2002

### *Key Elements of Baseline Calculation Methodologies*

Accurate baseline calculation methods have many desired criteria, some of which conflict and require trade-offs. The criteria include:

- Simplicity
- Ease of use and understanding
- Verifiability
- Accuracy
- Lack of bias
- Ability to handle weather-sensitive accounts appropriately
- Minimization of gaming
- Ability to be known prior to a customer's commitment to curtail
- Low cost

There are three main components or steps in any baseline calculation methodology

1. Data selection criteria (which data will serve as the basis for determining what the customer's load would otherwise have been, absent any demand response?)

2. Estimation method (what method will be used to develop a provisional baseline)

3. Adjustment method (what adjustments, if any, should be made to the provisional baseline to develop the final baseline).

The three components are discussed below.

There are four general options for data selection

- Single point (typically preceding hour, preceding day or most recent day with similar weather and system load conditions)
- Set of consecutive preceding days (typically 10 to 20)
- Sub-set of consecutive preceding days (typically top 5 of 10 or top 10 of 11)
- Full season

Different data selection criteria are appropriate for different estimation methods. No estimation method is required with single point data selection, but single point data selection has some disadvantages. Use of the preceding day would likely yield different weather and operating conditions than the day for which demand response was provided. If similar weather and system load conditions are used as criteria for selecting the day, the operations of the customer may have changed since the selected day. The full season data is only appropriate for regression models (not simple averages).

All data selection methods have exclusions such as days when curtailment occurred, weekends and holidays (for weekday baseline calculations) and very low load days.

There are three basic types of estimation methodologies

- Single point (only to be used with single point data selection method)
- Simple average (of data selected)
- Weather-based regression model (can be conditional or not). Conditional weather-based regression model automatically deletes weather terms if load data suggest specific account is not weather-sensitive. Therefore, a single methodology could be used for both weather-sensitive and non-weather-sensitive customers.

There are several adjustment methods:

- No adjustment
- Additive – a constant, the difference between the actual load and provisional baseline load for some period before curtailment, is added to the provisional baseline for all hours in the curtailment period.
- Scalar – the provisional baseline load for each hour of the curtailment period is multiplied by a fixed scalar. The scalar is the ratio of actual load to provisional baseline load for some period before the curtailment period.
- Weather-based adjustment – can be additive or scalar. A model is used to estimate load for the weather conditions of the days used in the provisional baseline and for the actual curtailment day. The difference or ratio of these estimates is used as the adjustment.

### *Key Findings from California Energy Commission Study*

Based on measures of bias and variability of the various combinations of data selection, estimation and adjustment methodologies, the key findings from the California Energy Commission study are as follows:

- Data selection
  - Longer input data series reduces bias and variability of weather models.
  - Decreased variability more noticeable for conditional weather models applied to non-weather-sensitive loads (particularly high-variability loads)
  - For summer loads, high 5 of 10 average reduces negative bias.
  - High 5 of 10 with additive adjustment gives lowest bias for all averages for both weather-sensitive and non-weather sensitive, with comparable variability
  - High 10 of 11 average gives some bias reduction, but not as much.
  - Other methods are all about the same.
  - For non-summer loads, high 5 of 10 inflates already positive bias. Others are pretty much equivalent except for high 10 of 11, which is slightly better. This result may not hold true for Ontario[a]
- Weather modelling

[a] California is a summer-peaking state. Since Ontario has both a summer and a winter peak, the positive bias in the winter may not exist in Ontario. For shoulder months, this result is likely to be true.

- For summer weather-sensitive accounts, weather models perform better than averages, but not dramatically
- Conditional weather models don't increase variability or bias for summer non-weather-sensitive loads
- Weather models don't perform better than averages for non-summer loads[a]

- Adjustments
  - Additive adjustments based on the 2 hours before the curtailment period reduce bias and variability of almost all methods, including weather models, for all load types
  - With additive adjustment, simple averages can perform just as well as complex weather models
  - Without adjustment, most averages understate load
  - Problems with adjustment to the two hours prior to curtailment -- Possibility of gaming by increasing load before curtailment, but legitimate pre-cooling will also increase baseline. Also, early/quick curtailment will reduce baseline
  - Additive adjustments to the hours before curtailment perform slightly better than scalar adjustments. Adjustments based on THI (Temperature Humidity Index) perform worse than those based on loads in hours before curtailment, but they are not susceptible to gaming.

### *Approaches Used in Other Markets*

The following table presents the baseline calculation methods used by other ISOs.

| ***Program(s)*** | ***Data Selection Window*** | ***Exclusions*** | ***Final Data Selection*** | ***Estimation Method*** | ***Adjustment Method*** |
|---|---|---|---|---|---|
| NY ISO Programs | Ten days commencing two days before curtailment day (in reverse chronological order) | Weekends, holidays, low output days | Top 5 of 10 | Simple Average | Elective weather-sensitive CBL formulation includes a scalar adjustment (with a floor and cap) based on the hours that begin 3 and 4 hours before the curtailment period. |
| ISO-NE Programs | Ten days commencing one day before curtailment day (in reverse chronological order) minus exclusions (minimum of 7 days) | Weekends, holidays, extreme output days | Entire 10 day window | Simple Average | Additive adjustment based on the two hours immediately before the curtailment period. |
| PJM Economic Program | Ten days commencing two days before curtailment day (in reverse chronological order) | Weekends, holidays, low output days | Top 5 of 10 | Simple Average | Elective weather-sensitive CBL formulation includes a THI adjustment based on the two hours immediately before the curtailment period. |
| PJM Emergency Program | Hour before | None | Hour before | None | None |

[a] This may only apply to shoulder months

### *Recommendations for Ontario*

For the IMO's Emergency Demand Response Program, the current baseline calculation method is relatively simple and consistent with PJM's emergency demand response program, and can be retained.

For dispatchable loads and any new demand response programs, the IMO could:

- Use average for estimation method provided the slight performance advantage of a weather model over adjusted average does not outweigh extra cost and complexity of the weather model (particularly considering the target customer group that would participate in any new IMO demand response programs in the short-term). This approach is also easy for customers to understand and calculate their baseline before making curtailment decision.

- Use either top 5 of 10 or the last 10 days as data selection criteria. The top 5 of 10 provides the lowest bias for summer accounts and is consistent with NYISO and PJM demand response measurement methodologies. Note that the top 5 of 10 may increase positive bias in non-summer accounts. The last 10 days is consistent with New England, but can underestimate load without an adjustment.

- Use an additive or scalar adjustment to two hours before curtailment where appropriate. The additive approach reduces bias and variability and is consistent with New England, but does allow the potential for gaming. Hence this approach may not be suitable where gaming is a major concern. Note that customers who curtail quickly/early will be penalized by reduced baseline using an additive adjustment. Also, legitimate pre-cooling would increase the customer's baseline. For these reasons, the IMO should consider providing customers with an option to use other adjustment methods if additive or scalar adjustment to two hours before curtailment are not appropriate.

- Additive or scalar adjustment to hours 3 and 4 before curtailment represents the next best performance and is consistent with NYISO's optional adjustment. This approach is not as susceptible to the problems of two hours before (eg, gaming, pre-cooling and early start effects).

- Consider the option of a THI adjustment to two hours before curtailment. This approach is slightly worse than additive/scalar adjustment to hours 3 and 4 at reducing bias and variability, but is not susceptible to gaming or other load-related problems of other methods and is consistent with PJM's optional adjustment.

- Provide participants with options to use something other than the default methodology – some baseline calculations are better for certain types of loads than others.

### *Load Sampling Techniques for Non-Interval Metered Loads*

The measurement approaches described above are suitable for individual customers with interval meters. For demand response programs involving direct load control of large groups of non-interval metered customers (such as load control of water heaters), load sampling approaches should be considered and would help to minimize the cost of re-activating these resources. Using these approaches only a small, representative sample of participating customers would need to be interval metered and the results from this sample would be extrapolated to all participating customers. This approach could incorporate elements of the data selection, estimation and adjustment mechanisms as appropriate.

The NYISO and CAISO have pilots in this area, and other ISOs are planning demand response programs based on load sampling techniques.

# APPENDIX C: GLOSSARY OF TERMS

| | |
|---|---|
| A/C | Air Conditioning |
| Aggregators | Entities that contract with customers for demand response and then offer the aggregated total demand response to the market. |
| ALM | Active Load Management – a program offered in the PJM market for load serving entities and other ALM providers to receive capacity credits for providing interruptible load. |
| Bill 210 | The Bill that became the *Electricity Pricing, Conservation and Supply Act, 2002*, outlining the Ontario Government's new policies regarding the electricity market. The most notable policy change was the introduction of a rate freeze for low volume and designated customers. |
| CA | California |
| CAISO | California Independent System Operator. |
| CEC | California Energy Commission |
| CPA | California Power Authority |
| CPP | Critical Peak Pricing – a variant on time-of-use pricing with a very high (critical) price for specific time periods. The timing of these critical peak periods is dynamic, but generally there are no more than 20 periods in a year. |
| CPP-F | Critical Peak Pricing-Fixed |
| CPP-V | Critical Peak Pricing-Variable |
| CPUC | California Public Utilities Commission |
| CSP | Curtailment Service Provider |
| DADRP | New York ISO's Day Ahead Demand Response Program |
| Direct Load Control | The customer's service provider, through some form of dispatch signal, controls a customer's consumption. Typically, a few appliances, such as water heaters or air conditioners would be controlled. |

| | |
|---|---|
| DR | Demand Response |
| DSM | Demand Side Management |
| Dx | Distribution |
| Economic Demand Response | In contrast to demand response based strictly on market price signals (ie, customers decide not to consume at certain price points), economic demand response involves some form of payment for customers not to consume. |
| EDA | Electricity Distributors Association |
| EdF | Electricite de France |
| EDRP | Emergency Demand Response Program |
| Elasticity | The percent increase in consumption divided by the increase in price |
| Emergency Demand Response | Typically, demand response that is utilized strictly for reliability purposes, just prior to implementing more drastic measures such as rolling blackouts. |
| FERC | United States Federal Energy Regulatory Commission |
| HOEP | Hourly Ontario Energy Price |
| HVAC | Heating, Ventilating, Air Conditioning |
| ICAP | Installed Capacity – the resource adequacy portion of New York's market. Participants are paid a credit for having available installed capacity. |
| ICAP SCR | Installed Capacity Special Case Resources – resources that are signed up under New York's ICAP SCR program that can provide demand response when called upon. |
| IMO | Independent Electricity Market Operator |
| IOU | Investor Owned Utility |
| ISO | Independent System Operator |
| LDC | Local Distribution Company |
| LMP | Locational Marginal Price |

| | |
|---|---|
| LSE | Load-Serving Entity |
| MCP | Market Clearing Price |
| MDC | Market Design Committee |
| MEU | Municipal Electric Utility |
| MPMA | Market Power Mitigation Agreement |
| NEPOOL | New England Power Pool |
| NSLS | Net System Load Shape – the general consumption pattern for customers served by a particular LDC. This pattern is applied to each (non-interval metered) customer's monthly consumption to develop hourly loads for that month for billing purposes. |
| NY | New York |
| NYISO | New York Independent System Operator |
| OEB | Ontario Energy Board |
| OEFC | Ontario Electricity Finance Corporation |
| OPG | Ontario Power Generation |
| OR | Operating Reserve |
| PG&E | Pacific Gas and Electric |
| PJM | Pennsylvania Jersey Maryland Interconnection Ltd |
| PPL | Pennsylvania Power and Light |
| Profiling Demand Response | Demand response that is measured through the use of load profiling rather than interval metering. |
| PSE | Puget Sound Energy |
| PUC | Public Utilities Commission |
| RIP | Resource Interface Party |
| RTP | Real-time pricing – typically offered in non-competitive markets to simulate the fluctuating price that would occur in a competitive market. The real-time price is often based on marginal supply costs. |

| | |
|---|---|
| SMD | Standard Market Design – an initiative by FERC to provide a standard framework for the design of competitive electricity markets. |
| SPP | State-wide Pricing Pilot |
| T&D | Transmission and Distribution? |
| THESL | Toronto Hydro Electric System Limited |
| TOU | Time-of-Use rates – typically with two or three pricing periods per day. For example, price during the off-peak period from 11 pm to 7 am might be 4 cents/kWh, whereas price during peak period from 7 am to 11 pm might be 7 cents/kWh. |
| TRC | Total Resource Costs |
| TRO | Transitional Rate Offering – provided by OPG under regulation to customers that previously participated in one or more of Ontario Hydro's incentive rates (eg, Real Time Pricing ("RTP") RTP I, RTP II, surplus load and load retention rates). |
| UCAP | Unforced Capacity – part of reliability and resource adequacy markets in U.S. markets such as PJM and NY. Installed capacity rated at summer conditions that is not on average experiencing a forced outage or forced. |
| UDC | Utility Distribution Companies (analogous to local distribution companies in Ontario) |
| Vertically Integrated Utility | A utility that provides generation, transmission and distribution services, along with all other services associated with the supply of electricity. |
| WMSC | Wholesale Market Service Charge |